Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

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Tab Number		Request
1	(1)	The utility's internal financial reports for the following periods: a. For the first and last month of the test year; b. For the entire test year; and c. For the 12 months or 5 quarters prior to the test year;
2	(2)	Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;
3	(3)	Federal income tax reconciliation for the test year;
4	(4)	A detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;
5	(5)	A detailed list of charitable contributions charged in the test year showing done and the amount according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all contributions shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all contributions of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all contributions of $2,500 and more shall be reported; and d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all contributions of $5,000 and more shall be reported; and e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution;
6	(6)	A list of advertising charged in the test year above the line showing expenditure by media and by subject matter according to the following guidelines: a. If the utility's annual gross revenues are less than $100,000, all expenditures shall be reported; b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all expenditures of $1,000 and more shall be reported; c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all expenditures of $2,500 and more shall be reported; and d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all expenditures of $5,000 and more shall be reported;

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16	(16)	A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows: a. For utilities with less than $100,000 in annual gross revenues, a list of all payments in excess of $1,000; and b. For utilities with annual gross revenues of $100,000 or between $100,000 and $10,000,000, a list of all payments in excess of $10,000; c. For utilities with annual gross revenues of $10,000,000 or between $10,000,000 and $100,000,000, a list of all payments in excess of $50,000; d. For utilities with annual gross revenues of $100,000,000 or in excess of $100,000,000, a list of all payments in excess of $100,000; and e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular entity shall be on a cumulative basis, indicating the number of items comprising the total amount of expenditure;
17	(17)	For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations;
18	(18)	Balance sheets and income statements for the previous 3 years;
19	(19)	Quarterly income statements for the previous 5 years;
20	(20)	Quarterly sales volumes for the previous 5 years, itemized for residential and other classifications of service;
21	(21)	A description of the utility's projected need for external capital for the 2 year period immediately following the test year;
22	(22)	The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately subsequent to the test year;
23	(23)	The provisions of any sinking funds associated with senior capital and a description of the rate at which any respective issues of senior capital will be retired, consistent with such sinking fund(s);
24	(24)	If the short-term debt component of total invested capital is volatile, the amount outstanding, on a monthly basis, during the test year, for each short-term indebtedness;

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25	(25.01)	If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below; The utility's internal financial reports for the following periods: a. For the first and last month of the test year; b. For the entire test year; and c. For the 12 months or 5 quarters prior to the test year;
26	(25.02)	Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;
27	(25.03)	Federal income tax reconciliation for the test year;
28	(25.04)	Detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;
29	(25.05)	Detailed list of charitable contributions charged in the test year showing donee and amount;
30	(25.06)	List of advertising charged in the test year above the line showing expenditure by media and by subject matter;
31	(25.07)	The utility's most recent cost of service study;
32	(25.08)	The utility's most recent construction budget;
33	(25.09)	The utility's chart of accounts, if different from the uniform system of accounts established by the commission as part of Puc 300, Puc 400, Puc 500, Puc 600 and Puc 700;
34	(25.10)	The utility's Securities and Exchange Commission 10K forms and 10Q forms, for the most recent 2 years;
35	(25.11)	Detailed list of all membership fees, dues, donations, for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount;
36	(25.12)	A list of any management audit and depreciation studies performed within the last 5 years, specifying whether same are on file with the commission;

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(1) The utility's internal financial reports for the following periods:

a. For the first and last month of the test year;

b. For the entire test year; and

c. For the 12 months or 5 quarters prior to the test year;

Please find attached internal financial reports (balance sheets and income statements) for the above requested periods.

Line	Account	Acct. No.	Jan 2012	Dec 2012	Test Year 2012
1	Organization		$ 24,808	$ 24,808	$ 24,808
2	*Software*		0	0	0
3	Other Intangible assets		0	0	0
4	**Total Intangible Plant**		$ 24,808	$ 24,808	$ 24,808
5					
6	Distribution Plant				
7	Land and land rights	360	$ 1,525,395	$ 1,627,441	$ 1,627,441
8	Structures and improvements	361	369,982	369,982	369,982
9	Station equipment	362	17,302,419	17,362,914	17,362,914
10	Poles, towers and fixtures	364	25,695,053	25,627,618	25,627,618
11	Overhead conductors, devices	365	34,663,994	34,849,460	34,849,460
12	Underground conduit	366	4,597,917	4,577,090	4,577,090
13	Underground conductors, device	367	9,678,486	9,726,252	9,726,252
14	Line transformers	368	16,576,326	16,659,915	16,659,915
15	Services	369	7,467,863	7,552,255	7,552,255
16	Meters	370	4,404,921	4,558,214	4,558,214
17	Leased Prop on Customers' Prem	372	1,145,189	1,170,298	1,170,298
18	*Street lighting, signal system*	373	4,284,784	4,225,154	4,225,154
19	Other	374	28,493	244,285	244,285
20	**Total Distribution Plant**		$ 127,740,821	$ 128,550,877	$ 128,550,877
21					
22	General / Common Plant				
23	*General plant*		$ 5,939,716	$ 5,939,716	$ 5,939,716
24	**Common plant**		15,000	0	0
25	Total General / Common Plant		$ 5,954,716	$ 5,939,716	$ 5,939,716
26	**Total Plant in Service**		$ 133,720,345	$ 134,515,402	$ 134,515,402
27					
28	Accumulated Depreciation & Amortization				
29	Intangible Assets		$ -	$ -	$ -
30	Transmission Plant		0	0	0
31	Land Rights, Substations, Structures		5,874,565	0	0
32	Poles, Towers, Fixtures		16,179,219	0	0
33	Overhead Conductors		10,330,489	0	0
34	Underground Conduits & Conductors		3,058,166	0	0
35	Line Transformers		9,383,329	0	0
36	Services		3,967,022	0	0
37	Meters		1,609,866	0	0
38	Lighting		2,999,122	0	0
39	*Other*		1,322,669	0	0
40	General / Common Plant		1,271,012	55,447,764	55,447,764
41	**Total Accum. Depr. & Amort.**		$ 55,995,458	$ 55,447,764	$ 55,447,764

Line	Account	Acct. No.	Jan 2012	Dec 2012	Test Year 2012
42					
43	Other Rate Base Items				
44	Materials and Supplies	154	$ 633,092	$ 415,932	$ 415,932
45	Prepayments	165	48,498	1,929,380	1,929,380
46	Cash Working Capital		0	0	0
47	CWIP	107	2,372,994	9,379,107	9,379,107
48	Deferred Tax Debit	183	12,870	231,612	231,612
49	Accumulated Deferred FIT	190	4,669,763	0	0
50	Other Deferred Credits	253	(5,908,367)	(21,042,739)	(21,042,739)
51	Deferred Tax Credit	282	(22,922,570)	0	0
52	*Other Rate Base Items*	182	5,438,045	28,064,224	28,064,224
53	**Customer Deposits**		(667,381)	(667,231)	(667,231)
	Total Other Rate Base Items		$ (16,323,057)	$ 18,310,284	$ 18,310,284
	Total Rate Base		$ 61,401,830	$ 97,377,922	$ 97,377,922

Line	Account	Acct. No.	Jan 2012	Dec 2012	Test Year 2012
1	**Purchased Power**	555	$ 4,796,085	$ 3,936,648	$ 36,839,918
2					
3	Transmission- Open Access	565	$ 911,648	$ 1,557,135	$ 15,301,182
4	Transmission- Other	560	8,538	4,392	(4,783)
5	**Transmission Expenses-O&M**		$ 920,186	$ 1,561,527	$ 15,296,399
6					
7	**Distribution O&M**				
8	Supervision & Eng	580	$ (10,789)	$ 187,745	$ 151,349
9	Load Dispatching	581	5,297	403,425	807,602
10	Substations	582	46,919	824	214,244
11	Overhead Lines	583	28,178	(907,795)	(291,326)
12	Underground Lines	584	10,414	(4,485)	89,470
13	Outdoor Lighting	585	1,209	-	14,049
14	Electric Meters	586	17,024	2,744	135,685
15	Customer Installation	587	5,358	-	64,515
16	Misc Expenses	588	69,825	8,773	575,211
17	Rents	589	222	-	2,161
18	Supervision & Eng	590	(16)	-	64
19	Structures	591	318	-	5,882
20	Substations	592	2,412	-	53,340
21	Substations-Trouble	592.1	5,464	-	12,712
22	Overhead Lines	593	150,026	224,490	1,805,277
23	OH Lines-Trouble	593.1	4,035	52,782	433,509
24	OH Lines-Veg Mgmt	593.2	126,107	241,032	1,072,504
25	Underground Lines	594	(4,886)	(680)	55,493
26	Line Transformers	595	5,106	-	39,761
27	Outdoor Lighting	596	9,299	-	75,627
28	Misc Distr Plant	597	8	-	2,537
29	*Total Distribution O&M*		$ 471,531	$ 208,854	$ 5,319,666
30					
31	**Customer Accounting**				
32	Supervision	901	$ 1,229	$ 9,137	$ 9,724
33	Meter Reading	902	13,360	165,487	529,994
34	Customer Records & Collection	903	64,078	33	448,716
35	Uncollectible Accounts	904	55,000	109,877	326,926
36	Uncollectible Accounts- Commodity	904	-	-	-
37	Misc Expenses	905	560	-	7,467
38	*Total Customer Accounting*		$ 134,227	$ 284,534	$ 1,322,827
39					

Line	Account	Acct. No.	Jan 2012	Dec 2012	Test Year 2012
40	**Customer Service & Information**				
41	Cust Service-Supervision	907	$ -	$ (12,213.33)	$ 37.25
42	Cust Assistance Expenses	908	5,603	(14,502)	84,858
43	Cust Service-Misc Expenses	910	1,359	12,511	90,006
44	*Total Customer Service & Info.*		$ 6,962	$ (14,205)	$ 174,901
45	*Total Customer Accounts*		$ 141,189	$ 270,329	$ 1,497,728
46					
47	**Administrative & General**				
48	A&G-Salaries	920	$ 118,324	$ 431,089	$ 2,196,920
49	A&G-Office Supplies	921	55,886	91,526	1,136,866
50	A&G-Outside Services Employed	923	76,012	120,365	3,595,737
51	Property Insurance	924	182,709	176,802	2,145,707
52	Injuries & Damages Insurance	925	60,265	61,701	427,811
53	Employee Pensions & Benefits	926	175,729	56,969	2,017,840
54	Regulatory Comm Expenses	928	34,384	35,349	535,251
55	A&G-Institutional/Goodwill Adv	930	4,019	-	18,211
56	A&G-Misc Expenses	930	3,126	-	83,566
57	A&G-Rents	931	11,122	5,907	94,492
58	A&G Maint-General Plant-Elec	935	2,163	-	14,578
59	*Total Administrative & General*		$ 723,738	$ 979,709	$ 12,266,980
60	*Total O&M Expense*		$ 7,052,729	$ 6,957,068	$ 71,220,691
61					
62	**Depreciation Expense**				
63	Intangible assets		$ -	$ -	$ -
64	Land Rights, Substations, Structures		47,006	-	282,609
65	Poles, Towers, Fixtures		93,011	-	560,890
66	Overhead Conductors		92,716	-	558,067
67	Underground Conduits & Conductors		28,452	-	171,180
68	Line Transformers		60,071	-	361,624
69	Services		27,017	-	163,501
70	Meters		15,972	-	97,744
71	Lighting		19,101	-	114,725
72	Other		20,946	394,945	2,556,835
73	*Total Depreciation Expense*		$ 404,293	$ 394,945	$ 4,867,174
74					
75	**General Taxes**				
76	Municipal tax		$ 250,038	$ 52,741	$ 2,778,746
77	Payroll tax		28,757	40,857	387,295
78	Other tax		-	-	-
79	Total General taxes		$ 278,795	$ 93,598	$ 3,166,041
80					

Line	Account	Acct. No.	Jan 2012	Dec 2012	Test Year 2012
81	**Income Taxes**				
82	FIT Expense		$ 191,416	$ -	$ (357,780)
83	SIT Expense		40,855	-	(416,629)
84	Total Income Tax		$ 232,270	$ -	$ (774,408)
85					
86	**Revenue Taxes**		-	-	-
87					
88	**Interest on Customer Deposits**		$ 21,026	$ -	$ 36,499
89					
90	**Total Expenses**		$ 7,989,114	$ 7,445,611	$ 78,515,996
91					
92	**Operating Revenue**				
93	Distribution	456Dx	$ 2,073,899	$ 2,064,254	$ 23,869,650
94	Commodity	440	4,919,866	3,690,301	36,665,612
95	Wholesale Transmission	456Tx	1,169,673	1,399,954	15,218,970
96	Forfeited discounts	450	9,642	12,165	117,251
97	Misc. service revenue	451	17,339	15,783	235,743
98	Rent from Electric property	454	6,569	25,931	283,642
99	Other revenue	456	85,684	112,732	1,033,380
100	Border/Fairpoint		-	37,151	165,571
101	Miscellaneous revenue		158,765	119,082	166,926
102			$ 8,441,437	$ 7,477,353	$ 77,756,745
103					
104	**Net operating income**		$ 452,323	$ 31,742	**$ (759,251)**
105					

	Description		**Calendar Year Ending Dec. 31, 2011**
	Assets		
Line	Utility plant	$	153,972,280
1	Depreciation reserve		(56,701,087)
2	CWIP		2,226,663
3	Net Utility plant	$	99,497,856
4			
5	Other property & investments	$	1,172,973
6			
7	Current assets		
8	Cash	$	3,907,944
9	Accounts receivable		10,771,158
10	Due from affiliates		2,554,671
11	Matls and supplies, Prepayments		2,961,896
12	Accrued revenues and other		1,237,436
13	Total Current assets	$	21,433,105
14			
15	Deferred debits	$	11,886,806
16	Goodwill		20,421,000
17	Total Other assets	$	32,307,806
18			
19	**Total Assets**	**$**	**154,411,740**

	Description		Calendar Year Ending Dec. 31, 2011
21			
22	**Capitalization & Liabilities**		
23	Capitalization		
24	Common stock	$	6,040,000
25	Preferred stock		-
26	Other Paid-in capital		40,053,584
27	Retained Earnings		33,302,155
28	Retained Earnings adjustments		(5,962,261)
29	Total Proprietary capital	$	73,433,478
30			
31	Long-term debt	$	15,000,000
32	Total Capitalization	$	88,433,478
33			
34	Current & accrued liabilities		
35	Notes payable		-
36	Accounts payable	$	7,693,449
37	Due to affiliates		878,656
38	Customer deposits		653,995
39	Accrued expenses		4,676,703
40	Total Current & accrued liabilities	$	13,902,803
41			
42	Deferred credits	$	8,421,906
43	Other Non-current liabilities		961,414
44	Customer advances for construction		-
45	Deferred income taxes		22,271,139
46	**Total Capitalization & Liabilities**	**$**	**133,990,740**

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
OPERATING REVENUE													
Residential	$ 2,127,263.05	$ 1,963,804.24	$ 1,862,029.68	$ 1,680,956.85	$ 1,366,981.83	$ 1,526,742.86	$ 1,784,966.07	$ 1,850,805.54	$ 1,599,988.25	$ 1,372,126.91	$ 1,563,732.06	$ 1,911,793.74	$ 20,611,191.08
Commercial & Industrial	$ 2,087,075.11	$ 2,000,303.88	$ 1,858,314.31	$ 1,780,626.73	$ 1,642,267.81	$ 1,812,470.30	$ 1,718,755.68	$ 2,038,139.74	$ 1,914,280.83	$ 1,673,029.78	$ 1,596,697.64	$ 1,754,476.47	$ 21,876,438.28
Street Lighting	$ 5,339.45	$ 5,055.49	$ 4,721.14	$ 5,216.15	$ 4,027.54	$ 4,581.08	$ 4,617.50	$ 4,324.58	$ 4,293.66	$ 4,232.52	$ 5,241.02	$ 5,059.80	$ 56,709.93
Refund Provision	$ 180,749.49	$ (26,748.94)	$ (199,629.88)	$ (247,336.52)	$ (36,778.01)	$ 381,582.82	$ 49,767.15	$ 915,127.47	$ 579,674.05	$ (41,778.31)	$ (458,566.91)	$ 441,627.32	$ 1,537,689.73
Sales of Electric Energy	$ 4,400,427.10	$ 3,942,414.67	$ 3,525,435.25	$ 3,219,463.21	$ 2,976,499.17	$ 3,725,377.06	$ 3,558,106.40	$ 4,808,397.33	$ 4,098,236.79	$ 3,007,610.90	$ 2,707,103.81	$ 4,112,957.33	$ 44,082,029.02
Gas Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Revenues													
Forfeited Discounts-Electric	$ 11,687.11	$ 17,741.26	$ (1,590.10)	$ 10,309.12	$ 9,823.38	$ 8,127.09	$ 9,448.83	$ 9,439.02	$ 14,476.78	$ 12,517.67	$ 8,546.99	$ 7,403.78	$ 117,930.93
Misc Service Revenue-Electric	$ 17,030.74	$ 17,150.30	$ 17,795.57	$ 22,346.65	$ 18,932.94	$ 19,060.91	$ 17,845.05	$ 18,479.35	$ 18,177.02	$ 18,640.15	$ 19,226.92	$ 35,428.40	$ 240,114.00
Open Access Rev-DSM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,453.00	$ 19,453.00
Open Access Rev-Cust Charge	$ 222,367.35	$ 219,397.66	$ 220,060.64	$ 220,548.90	$ 220,333.38	$ 219,176.55	$ 220,874.97	$ 220,974.04	$ 220,564.11	$ 222,638.81	$ 219,572.75	$ 220,433.69	$ 2,646,942.85
Rent From Electric Property	$ 6,281.04	$ 6,281.04	$ 96,425.05	$ 28,694.43	$ 23,120.75	$ 22,997.46	$ 22,997.46	$ 23,483.96	$ 25,029.48	$ 22,998.03	$ 22,619.23	$ 23,007.94	$ 323,935.87
Open Access Rev-Access Charge	$ 37,472.20	$ 15,670.96	$ 14,718.59	$ 14,199.92	$ 13,362.38	$ 15,015.54	$ 16,549.34	$ 18,058.66	$ 15,786.63	$ 14,460.91	$ 13,849.17	$ 14,420.57	$ 203,564.87
Open Access Rev-Transmission	$ 1,132,547.11	$ 1,149,167.50	$ 1,153,850.98	$ 1,053,106.02	$ 1,362,793.47	$ 1,524,611.99	$ 1,454,223.02	$ 1,313,474.44	$ 936,954.12	$ 964,725.74	$ 1,155,982.37	$ 1,400,523.21	$ 14,601,959.97
Open Access Rev-Distribution	$ 1,980,560.75	$ 1,704,840.37	$ 1,855,590.53	$ 1,621,056.40	$ 1,579,505.19	$ 1,804,576.65	$ 2,124,537.95	$ 1,647,635.28	$ 1,612,043.87	$ 1,503,887.98	$ 1,644,232.19	$ 1,732,371.18	$ 20,810,838.34
Other Elec Rev-Misc	$ 5,572.13	$ 5,349.46	$ (186.83)	$ 22,405.89	$ 6,221.96	$ 49,488.20	$ 51,295.76	$ 4,285.24	$ 17,387.00	$ 1,303.52	$ 28,758.78	$ 5,072.81	$ 196,953.92
Other Operating Revenue	$ 3,413,518.43	$ 3,135,598.55	$ 3,356,664.43	$ 2,992,667.33	$ 3,234,093.45	$ 3,663,054.39	$ 3,917,772.38	$ 3,255,829.99	$ 2,860,419.01	$ 2,761,172.81	$ 3,112,788.40	$ 3,458,114.58	$ 39,161,693.75
Other Gas Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Other Revenues	$ 3,413,518.43	$ 3,135,598.55	$ 3,356,664.43	$ 2,992,667.33	$ 3,234,093.45	$ 3,663,054.39	$ 3,917,772.38	$ 3,255,829.99	$ 2,860,419.01	$ 2,761,172.81	$ 3,112,788.40	$ 3,458,114.58	$ 39,161,693.75
TOTAL OPERATING REVENUE	**$ 7,813,945.53**	**$ 7,078,013.22**	**$ 6,882,099.68**	**$ 6,212,130.54**	**$ 6,210,592.62**	**$ 7,388,431.45**	**$ 7,475,878.78**	**$ 8,064,227.32**	**$ 6,958,655.80**	**$ 5,768,783.71**	**$ 5,819,892.21**	**$ 7,571,071.91**	**$ 83,243,722.77**
OPERATING EXPENSES													
Purchased Power-Variable	$ -	$ -	$ (164,530.00)	$ -	$ -	$ (141,871.75)	$ -	$ -	$ 795,615.57	$ -	$ -	$ 194,963.15	$ 684,176.97
Purchased Power-Fixed & SO	$ 4,210,146.46	$ 3,626,634.23	$ 3,395,073.54	$ 3,151,224.25	$ 3,212,955.28	$ 3,627,360.76	$ 4,043,785.16	$ 3,974,823.11	$ 3,488,585.78	$ 2,750,308.37	$ 3,286,413.06	$ 4,146,845.70	$ 42,914,155.70
PP-NEP-Access Charge-Elim	$ 37,472.20	$ 15,670.99	$ 14,809.70	$ 14,199.92	$ 13,362.38	$ 15,015.54	$ 16,549.34	$ 18,058.66	$ 15,786.63	$ 14,460.91	$ 13,849.17	$ 14,420.57	$ 203,656.01
Purchased Energy	$ 4,247,618.66	$ 3,642,305.22	$ 3,245,353.24	$ 3,165,424.17	$ 3,226,317.66	$ 3,500,504.55	$ 4,060,334.50	$ 3,992,881.77	$ 4,299,987.98	$ 2,764,769.28	$ 3,300,262.23	$ 4,356,229.42	$ 43,801,988.68
Fuel for Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Expenses													
Steam Power Generation Expenses-O&M													
Operate Steam Power Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maint Steam Power Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Steam Power Generation Expenses-O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Generation Expenses-O&M													
Operate Other Power Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maint Other Power Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Power Supply Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Other Power Generation Expenses-O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Hydro Power Generation Expenses-O&M													
Operate Hydro Power Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maint Hydro Power Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Hydro Power Generation Expenses-O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses-O&M													
Trans Oper-Supervision & Eng	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,226.53	$ 1,044.47	$ -	$ -	$ -	$ 3,271.00
Trans Oper-Load Dispatching	$ (3.04)	$ -	$ -	$ 42.90	$ -	$ 0.78	$ 14.23	$ -	$ -	$ -	$ -	$ -	$ 54.87
Schd, Sys Cntrl & Dispatch Srv	$ 38,100.29	$ 70,039.37	$ 52,104.89	$ 40,131.49	$ 34,172.67	$ 33,900.58	$ 41,152.78	$ 41,914.96	$ 63,586.21	$ 50,629.44	$ 40,298.21	$ 38,510.92	$ 544,541.81
Trans Oper-Substations	$ 1,337.86	$ 3,069.95	$ 2,306.15	$ 2,320.52	$ 1,376.92	$ 2,294.25	$ 2,238.33	$ (554.43)	$ 1,477.02	$ 5,259.56	$ 3,546.25	$ 2,316.20	$ 26,988.58
Trans Oper-Overhead Lines	$ 1,402.40	$ -	$ -	$ -	$ -	$ 87.93	$ -	$ -	$ -	$ -	$ -	$ 65.64	$ 1,555.97
Trans Oper-Wheeling	$ 796,019.58	$ 797,664.52	$ 804,196.86	$ 708,891.13	$ 1,050,202.23	$ 1,061,591.34	$ 1,105,992.69	$ 986,399.18	$ 594,765.34	$ 598,698.06	$ 830,710.09	$ 896,742.77	$ 10,231,873.79
Elec Rev Wheeling-Elim	$ 303,667.49	$ 271,361.01	$ 327,633.23	$ 260,643.00	$ 302,654.77	$ 454,314.77	$ 281,087.05	$ 254,280.50	$ 380,160.37	$ 139,891.04	$ 480,017.77	$ 316,645.02	$ 3,772,356.02
Sale for Resale-Tran CR-Elim	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (2,082.16)	$ (24,985.92)
Trans Oper-Misc Expenses	$ 66.55	$ 5,810.46	$ 2,112.91	$ 454.19	$ (49.61)	$ 371.20	$ 131.96	$ 348.84	$ 249.12	$ 369.23	$ 964.03	$ 10,434.47	$ 21,263.35
Oper Transmission Facilities	$ 1,138,508.97	$ 1,145,863.15	$ 1,186,271.88	$ 1,010,401.07	$ 1,386,274.82	$ 1,550,478.69	$ 1,428,534.88	$ 1,282,533.42	$ 1,039,200.37	$ 792,765.17	$ 1,353,454.19	$ 1,262,632.86	$ 14,576,919.47

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Trans Maint-Supervision & Eng	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 468.24	$ 468.24
Trans Maint-Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24.01	$ -	$ -	$ 24.01
Trans Maint-Substations	$ -	$ 341.41	$ 12,973.02	$ 936.65	$ (121.44)	$ (116.95)	$ -	$ 8.60	$ (5.50)	$ -	$ -	$ 2,620.33	$ 16,636.12
Trans Maint-Substation-Trouble	$ -	$ -	$ -	$ -	$ -	$ 84.20	$ 39.50	$ 117.31	$ -	$ -	$ -	$ 159.91	$ 400.92
Trans Maint-Overhead Lines	$ (668.45)	$ (421.16)	$ (410.26)	$ (674.48)	$ (757.06)	$ (403.78)	$ (861.74)	$ (861.08)	$ (851.74)	$ (158.76)	$ (163.85)	$ (1,111.65)	$ (7,344.01)
Trans Maint-Switch-Unplanned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,062.49	$ (9,062.49)	$ -	$ -	$ -	$ -
Maint Transmission Facilities	$ (668.45)	$ (79.75)	$ 12,562.76	$ 262.17	$ (878.50)	$ (436.53)	$ (822.24)	$ 8,327.32	$ (9,919.73)	$ (134.75)	$ (163.85)	$ 2,136.83	$ 10,185.28
Subtotal Transmission Expenses-O&M	$ 1,137,840.52	$ 1,145,783.40	$ 1,198,834.64	$ 1,010,663.24	$ 1,385,396.32	$ 1,550,042.16	$ 1,427,712.64	$ 1,290,860.74	$ 1,029,280.64	$ 792,630.42	$ 1,353,290.34	$ 1,264,769.69	$ 14,587,104.75
Distribution Expenses-O&M													
Dist Oper-Supervision & Eng	$ (9,609.42)	$ 6,935.92	$ 74,996.30	$ 2,563.67	$ (31,131.95)	$ (75,026.94)	$ 43,092.58	$ (11,931.07)	$ 26,233.94	$ 33.56	$ 76,360.04	$ (40,629.87)	$ 61,886.76
Dist Oper-Load Dispatching	$ 14,050.66	$ 8,628.69	$ 9,435.02	$ 7,850.97	$ 5,723.53	$ 5,174.73	$ 4,139.58	$ 3,861.40	$ 3,995.90	$ 5,064.78	$ 5,237.41	$ 4,909.73	$ 78,072.40
Dist Oper-Substations	$ 20,544.84	$ 37,538.21	$ 68,991.35	$ 62,900.28	$ 4,432.20	$ 9,977.30	$ 10,016.54	$ 8,265.39	$ 27,160.86	$ 82,411.73	$ 18,347.35	$ 25,013.26	$ 375,599.31
Dist Oper-Overhead Lines	$ 17,193.93	$ 17,859.41	$ 54,457.86	$ 32,214.86	$ 34,013.34	$ 31,559.54	$ 23,741.82	$ 31,649.64	$ 31,619.82	$ 38,042.53	$ 28,642.60	$ 36,572.68	$ 377,568.03
Dist Oper-Underground Lines	$ 6,683.14	$ 8,160.73	$ 3,205.36	$ 1,147.62	$ 9,936.08	$ 19,346.43	$ 8,169.83	$ 9,971.87	$ 11,455.49	$ 11,885.58	$ 15,917.20	$ 7,280.92	$ 113,160.25
Dist Oper-Outdoor Lighting	$ 2,736.08	$ 2,598.83	$ 4,236.75	$ 2,422.50	$ 3,047.62	$ 1,182.85	$ 1,437.06	$ 1,864.77	$ 1,694.17	$ 2,753.07	$ 1,411.08	$ 2,138.69	$ 27,523.47
Dist Oper-Electric Meters	$ 25,822.76	$ 22,057.45	$ 26,898.66	$ 22,025.80	$ 22,087.90	$ 25,158.72	$ 19,130.50	$ 20,289.07	$ 21,773.68	$ 24,563.87	$ 19,736.15	$ 24,182.34	$ 273,726.90
Dist Oper-CustomerInstallation	$ 9,919.85	$ 10,385.77	$ 25,025.12	$ 10,153.32	$ 13,870.51	$ 22,978.96	$ 13,499.28	$ 14,002.16	$ 11,773.39	$ 11,897.72	$ 10,395.93	$ 13,827.53	$ 167,729.54
Dist Oper-Misc Expenses	$ 55,164.10	$ 70,503.11	$ 179,508.80	$ 135,223.62	$ 72,717.83	$ 73,081.67	$ 64,782.61	$ 53,518.01	$ 91,056.11	$ 62,519.34	$ 104,188.25	$ 93,486.63	$ 1,055,750.08
Dist Oper-Rents	$ 75.00	$ 650.00	$ 60.00	$ 40.00	$ -	$ 60.00	$ -	$ -	$ -	$ 60.00	$ -	$ -	$ 945.00
Rents-Building-Dist-Elim	$ 337.25	$ 337.25	$ 337.25	$ 222.29	$ 222.29	$ 222.29	$ 222.29	$ 222.29	$ 222.29	$ 222.29	$ 222.29	$ 222.29	$ 3,012.36
Operate Dist Facilities	$ 142,918.19	$ 185,655.37	$ 447,152.47	$ 276,764.93	$ 134,919.35	$ 113,715.55	$ 188,232.09	$ 131,713.53	$ 226,985.65	$ 239,454.47	$ 280,458.30	$ 167,004.20	$ 2,534,974.10
Dist Maint-Supervision & Eng	$ 27.02	$ 28.42	$ 70.13	$ 26.46	$ 23.78	$ 15.95	$ 19.62	$ 28.86	$ 16.94	$ 533.09	$ 52.40	$ 41.80	$ 884.47
Dist Maint-Structures	$ 786.63	$ 2,250.28	$ 2,205.65	$ 590.37	$ 644.79	$ 390.47	$ -	$ 730.04	$ 397.50	$ 690.59	$ 103.54	$ 751.96	$ 9,541.82
Dist Maint-Substations	$ 2,353.97	$ 12,918.76	$ 34,959.70	$ 18,478.57	$ 7,914.86	$ 17,031.44	$ 13,583.26	$ 10,017.46	$ 2,878.56	$ 17,439.22	$ 7,118.83	$ 6,776.02	$ 151,470.65
Dist Maint-Substations-Trouble	$ (553.60)	$ 5,024.28	$ 3,940.94	$ 3,705.18	$ 479.27	$ 18,056.26	$ 1,548.59	$ 302.04	$ 2,650.42	$ 6,123.85	$ 11,948.55	$ 524.98	$ 53,750.76
Dist Maint-Overhead Lines	$ 159,905.62	$ 122,010.21	$ (92,960.84)	$ 248,750.43	$ (106,906.38)	$ 88,719.24	$ 48,871.60	$ 209,557.30	$ 117,137.95	$ 222,818.34	$ (326,439.28)	$ 29,155.88	$ 720,620.07
Dist Maint-OH Lines-Trouble	$ 2,736.51	$ 177.56	$ 4,300.37	$ 766.65	$ 2,593.02	$ 2,393.72	$ 2,317.66	$ 6,559.09	$ 2,596.74	$ 3,787.64	$ 4,430.10	$ 3,381.74	$ 36,040.80
Dist Maint-OH Lines-Veg Mgmt	$ 91,404.18	$ 53,396.90	$ 1,199,242.55	$ (1,517.97)	$ (40,773.78)	$ 168,917.28	$ 219,633.65	$ 522.65	$ 180,830.21	$ (35,105.44)	$ 112,601.72	$ 187,524.55	$ 2,136,676.50
Dist Maint-Underground Lines	$ (8,668.03)	$ (216.62)	$ (1,558.35)	$ 2,201.52	$ 799.35	$ 1,636.41	$ 1,105.06	$ (4,362.42)	$ 790.36	$ 4,917.89	$ 2,941.77	$ 6,565.13	$ 6,152.07
Dist Maint-Line Transformers	$ 1,239.45	$ 784.27	$ 1,708.66	$ 10,093.19	$ 9,474.84	$ 6,914.84	$ 2,962.56	$ 4,425.46	$ 4,464.44	$ 8,736.72	$ 9,716.42	$ 11,233.74	$ 71,754.59
Dist Maint-Outdoor Lighting	$ 7,579.13	$ 4,083.69	$ (31,674.12)	$ 6,732.72	$ 10,559.84	$ 7,549.31	$ 5,870.64	$ 760.30	$ 4,107.13	$ 23,027.99	$ 13,679.99	$ 27,902.61	$ 80,179.23
Dist Maint-Electric Meters	$ (564.52)	$ 382.43	$ 173.71	$ 201.18	$ 3,411.14	$ 252.50	$ 457.72	$ 124.14	$ 555.98	$ 96.66	$ 1,741.39	$ 7,183.47	$ 14,015.80
Dist Maint-Misc Distr Plant	$ 12.99	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.99
Maint Distribution Facilities	$ 256,259.35	$ 200,840.18	$ 1,120,408.40	$ 290,028.30	$ (111,779.27)	$ 311,877.42	$ 296,370.36	$ 228,664.92	$ 316,426.23	$ 253,066.55	$ (162,104.57)	$ 281,041.88	$ 3,281,099.75
Subtotal Distribution Expenses-O&M	$ 399,177.54	$ 386,495.55	$ 1,567,560.87	$ 566,793.23	$ 23,140.08	$ 425,592.97	$ 484,602.45	$ 360,378.45	$ 543,411.88	$ 492,521.02	$ 118,353.73	$ 448,046.08	$ 5,816,073.85
Gas Expenses-O&M													
Production Expenses-Gas	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operate Gas Facilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Maintain Gas Facilities	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal Gas Expenses-O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Expenses-O&M													
Cust Acct-Supervision	$ 4,578.09	$ 4,807.64	$ 2,354.33	$ 3,390.53	$ 3,110.21	$ 3,014.51	$ 1,176.42	$ 1,649.36	$ 1,374.44	$ 1,565.87	$ 1,429.74	$ 1,402.16	$ 29,853.30
Cust Acct-Meter Reading Exp	$ 19,415.41	$ 20,373.21	$ 18,149.26	$ 12,922.32	$ 17,954.19	$ 18,027.72	$ 16,031.32	$ 15,114.21	$ 20,088.78	$ 16,246.79	$ 15,256.45	$ 21,854.19	$ 211,433.85
Cust Records & Collection	$ 85,445.68	$ 51,686.83	$ 55,491.81	$ 84,289.00	$ 80,875.69	$ 95,495.09	$ 76,447.57	$ 77,359.15	$ 85,690.88	$ 72,442.58	$ 77,729.71	$ 75,604.40	$ 918,558.39
Uncollectible Accounts	$ 38,800.00	$ 3,000.00	$ 92,618.20	$ 32,000.00	$ 32,000.00	$ 32,000.00	$ 32,000.00	$ 32,000.00	$ 92,045.03	$ 55,000.00	$ 55,000.00	$ 66,941.63	$ 563,404.86
Cust Acct-Misc Expenses	$ (1,786.94)	$ 534.80	$ 922.54	$ 647.33	$ 527.60	$ 452.39	$ 582.39	$ 710.92	$ 515.41	$ 722.12	$ 291.72	$ 400.30	$ 4,520.58
Customer Accts Oper Exp-Elec	$ 146,452.24	$ 80,402.48	$ 169,536.14	$ 133,249.18	$ 134,467.69	$ 148,989.71	$ 126,237.70	$ 126,833.64	$ 199,714.54	$ 145,977.36	$ 149,707.62	$ 166,202.68	$ 1,727,770.98
Cust Service-Supervision	$ -	$ -	$ -	$ -	$ -	$ 475.92	$ -	$ -	$ 273.14	$ -	$ 113.32	$ -	$ 862.38
Cust Assistance Expenses	$ 4,949.87	$ 5,415.70	$ 19,972.24	$ 4,290.68	$ 2,892.13	$ 1,629.26	$ 3,471.88	$ 665.99	$ 5,013.91	$ 11,183.94	$ 9,848.10	$ 668.76	$ 70,002.46
Info&Instruct Advertising Exp	$ -	$ 400.00	$ (15,975.53)	$ 871.90	$ 1,828.72	$ 445.55	$ 92.92	$ 3,613.45	$ 220.04	$ 525.99	$ 347.74	$ 7,874.88	$ 245.66
Cust Service-Misc Expenses	$ 10,367.54	$ 15,603.34	$ 25,143.25	$ 14,955.58	$ 3,591.88	$ 13,363.11	$ 9,295.43	$ 6,855.24	$ (16,166.57)	$ 9,162.60	$ 3,106.62	$ 17,026.50	$ 112,304.52
Sales Expense-Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.46	$ -	$ 18.22	$ 17.47	$ 14.58	$ 62.73
Demo & Selling Expenses	$ -	$ 2,076.57	$ 78,216.13	$ 656.17	$ 3,346.53	$ 1,657.01	$ 1,552.26	$ 1,195.99	$ 7,437.87	$ 1,662.56	$ 3,888.30	$ 4,978.02	$ 106,667.41
Sales-Misc Expenses	$ 4.69	$ 3.75	$ 2.81	$ 12.19	$ 2.81	$ 5.62	$ 1.87	$ 1.87	$ 12.18	$ 0.94	$ 4.69	$ 22.50	$ 75.92
Cust Service & Info Expenses	$ 15,322.10	$ 23,499.36	$ 107,358.90	$ 20,786.52	$ 11,662.07	$ 17,576.47	$ 14,414.36	$ 12,345.00	$ (3,209.43)	$ 22,554.25	$ 17,326.24	$ 30,585.24	$ 290,221.08

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Administration Expenses-O&M													
A&G-Salaries	$ 44,952.25	$ 200,923.52	$ 200,185.27	$ 95,999.06	$ 199,352.03	$ 163,051.97	$ 128,704.03	$ 212,972.39	$ 17,365.64	$ 185,194.39	$ 321,466.69	$ 80,945.04	$ 1,851,112.28
A&G-Office Supplies	$ 68,833.09	$ 128,794.61	$ 155,932.21	$ 6,928.69	$ 75,482.60	$ 98,012.20	$ 66,075.99	$ 80,648.29	$ 78,376.83	$ 33,332.63	$ 48,749.23	$ 56,576.48	$ 897,742.85
A&G Srv Co Deprec Exp PAM	$ -	$ 1,629.37	$ 813.22	$ 780.30	$ 780.30	$ 780.30	$ 833.38	$ 782.00	$ 4,327.10	$ 1,140.77	$ 1,224.51	$ 2,216.59	$ 15,307.84
A&G Srv Co Amort Ltd Elec Plnt	$ -	$ 41,160.07	$ 18,426.66	$ 12,442.38	$ 12,961.98	$ (21,462.74)	$ 13,767.62	$ 11,229.70	$ 2,120.47	$ 26,199.33	$ 11,112.79	$ 11,514.62	$ 139,472.88
A&G Srv Co Deprec Exp LAB	$ -	$ 614.41	$ 307.21	$ 307.21	$ 307.21	$ 307.21	$ 307.21	$ 307.21	$ 307.21	$ 307.21	$ 307.21	$ 306.39	$ 3,685.69
A&G Srv Co AFUDC Credit	$ -	$ (6,856.49)	$ (3,717.49)	$ (2,684.61)	$ (2,664.19)	$ (2,975.71)	$ (3,452.34)	$ (3,130.05)	$ (1,098.63)	$ (2,221.59)	$ (2,590.09)	$ (3,074.18)	$ (34,465.37)
A&G-Outside Services Employed	$ 30,900.51	$ 40,238.53	$ 19,334.58	$ 51,512.60	$ 27,552.68	$ 28,750.54	$ 24,050.28	$ 58,911.59	$ 29,653.23	$ 138,431.37	$ 43,587.18	$ 76,263.81	$ 569,186.90
Property Insurance	$ 41,726.27	$ 40,000.00	$ 36,828.40	$ 41,705.09	$ 36,647.16	$ 41,784.39	$ 41,655.82	$ 46,537.41	$ 42,437.85	$ 42,618.02	$ 37,699.00	$ 40,045.50	$ 489,684.91
Injuries & Damages Insurance	$ 92,550.43	$ 21,650.31	$ 320,194.89	$ (74,553.78)	$ 88,451.72	$ 16,896.73	$ 26,339.84	$ 24,025.75	$ (4,941.86)	$ 15,184.52	$ 23,136.38	$ 36,769.95	$ 585,704.88
Employee Pensions & Benefits	$ 261,584.29	$ 141,167.56	$ 483,916.20	$ 133,765.61	$ 118,013.07	$ 103,980.23	$ 148,323.61	$ 183,145.90	$ 99,490.40	$ 120,700.93	$ 178,349.59	$ 117,718.97	$ 2,090,156.36
Regulatory Comm Expenses	$ 36,758.28	$ (183,872.18)	$ 122,985.61	$ 42,318.79	$ 30,096.33	$ 32,507.43	$ (8,230.88)	$ 63,880.42	$ 15,176.17	$ 36,979.98	$ 32,932.01	$ 33,458.72	$ 254,990.68
A&G-Institutional/Goodwill Adv	$ 3.46	$ 98.84	$ 871.40	$ 39.66	$ 6.08	$ 1,105.64	$ 81.99	$ 1,206.85	$ 1,451.58	$ 164.79	$ 2,879.16	$ 7,410.97	$ 15,320.42
A&G-Misc Expenses	$ 5,985.84	$ 4,287.38	$ 3,148.11	$ 2,144.52	$ 1,724.21	$ 1,862.03	$ 2,058.03	$ 1,294.36	$ 1,153.46	$ 2,253.18	$ 2,934.73	$ 5,022.70	$ 33,868.55
A&G-Research & Development	$ -	$ 5,101.05	$ 5,498.81	$ -	$ -	$ -	$ -	$ -	$ -	$ 168.21	$ 4.35	$ -	$ 10,772.42
A&G-Rents	$ 7,663.38	$ 6,500.54	$ 29,802.54	$ 10,864.37	$ 2,419.83	$ 64,383.90	$ 10,827.96	$ 10,808.24	$ 11,280.29	$ 12,587.40	$ 8,668.64	$ 10,831.21	$ 186,638.30
Airplane Rent Expense-Elim	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 244.80	$ 2,937.60
NE Share CSS Costs-Elim	$ 51.78	$ 51.67	$ 51.58	$ 51.48	$ 51.38	$ 51.28	$ 51.18	$ 51.08	$ 50.98	$ 50.88	$ 50.78	$ 50.68	$ 614.75
Administrative Oper Exp-Elec	$ 591,254.38	$ 441,733.99	$ 1,394,824.00	$ 321,866.17	$ 591,427.19	$ 529,280.20	$ 451,638.52	$ 692,915.94	$ 297,395.52	$ 613,336.82	$ 710,756.96	$ 476,302.25	$ 7,112,731.94
A&G Maint-General Plant-Elec	$ 4,455.00	$ 4,718.18	$ 2,140.28	$ 1,677.05	$ 1,116.09	$ 2,079.08	$ 1,177.34	$ 2,269.22	$ 7,925.35	$ 1,897.69	$ 2,931.37	$ 3,480.91	$ 35,867.56
Administrative Maint Expenses	$ 4,455.00	$ 4,718.18	$ 2,140.28	$ 1,677.05	$ 1,116.09	$ 2,079.08	$ 1,177.34	$ 2,269.22	$ 7,925.35	$ 1,897.69	$ 2,931.37	$ 3,480.91	$ 35,867.56
Subtotal Administration Expenses-O&M	$ 595,709.38	$ 446,452.17	$ 1,396,964.28	$ 323,543.22	$ 592,543.28	$ 531,359.28	$ 452,815.86	$ 695,185.16	$ 305,320.87	$ 615,234.51	$ 713,688.33	$ 479,783.16	$ 7,148,599.50
Total Operation Expenses	$ 2,034,455.88	$ 1,877,154.35	$ 3,305,143.39	$ 1,763,067.87	$ 2,258,751.12	$ 2,360,040.62	$ 2,209,057.55	$ 2,246,341.53	$ 1,760,086.65	$ 1,814,088.07	$ 2,511,703.31	$ 2,102,727.23	$ 26,242,617.57
Total Maintenance Expenses	$ 260,045.90	$ 205,478.61	$ 1,135,111.44	$ 291,967.52	$ (111,541.68)	$ 313,519.97	$ 296,725.46	$ 239,261.46	$ 314,431.85	$ 254,829.49	$ (159,337.05)	$ 286,659.62	$ 3,327,152.59
O&M Expenses	$ 2,294,501.78	$ 2,082,632.96	$ 4,440,254.83	$ 2,055,035.39	$ 2,147,209.44	$ 2,673,560.59	$ 2,505,783.01	$ 2,485,602.99	$ 2,074,518.50	$ 2,068,917.56	$ 2,352,366.26	$ 2,389,386.85	$ 29,569,770.16
Depreciation & Amortization													
Depreciation Expense	$ -	$ -	$ 5,701.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,701.00
Depr Exp-Asset/Held/Sale	$ 289,855.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 289,855.16
Depreciation Expense - LAB	$ 3,453.48	$ 3,453.48	$ 3,390.99	$ 3,453.48	$ 3,453.48	$ 3,395.79	$ 3,453.48	$ 3,453.48	$ 3,395.79	$ 3,461.03	$ 3,468.58	$ 3,410.89	$ 41,243.95
Depreciation Expense - PAM	$ 388,012.54	$ 389,240.76	$ 390,927.07	$ 392,279.28	$ 394,790.33	$ 396,651.27	$ 397,059.84	$ 397,717.10	$ 398,119.39	$ 398,329.22	$ 398,791.31	$ 399,898.80	$ 4,741,816.91
Depreciation Expense-AR Costs	$ -	$ -	$ 62.49	$ -	$ -	$ 57.69	$ -	$ -	$ 57.69	$ -	$ -	$ 57.69	$ 235.56
Depreciation	$ 681,321.18	$ 392,694.24	$ 400,081.55	$ 395,732.76	$ 398,243.81	$ 400,104.75	$ 400,513.32	$ 401,170.58	$ 401,572.87	$ 401,790.25	$ 402,259.89	$ 403,367.38	$ 5,078,852.58
Amortization-Regulatory Debits	$ 21,208.58	$ 21,208.58	$ 7,834.28	$ 21,026.00	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 239,486.48
Amortization	$ 21,208.58	$ 21,208.58	$ 7,834.28	$ 21,026.00	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 21,026.13	$ 239,486.48
Depreciation & Amortization	$ 702,529.76	$ 413,902.82	$ 407,915.83	$ 416,758.76	$ 419,269.94	$ 421,130.88	$ 421,539.45	$ 422,196.71	$ 422,599.00	$ 422,816.38	$ 423,286.02	$ 424,393.51	$ 5,318,339.06
Taxes Other than Income Taxes													
Tx Oth Inc Tx-Fed Unempl Comp	$ 1,665.94	$ 195.45	$ (6,909.88)	$ -	$ 16.39	$ 77.19	$ 22.06	$ 24.20	$ 19.78	$ -	$ 28.17	$ (362.53)	$ (5,223.23)
Federal Unemployment	$ 1,665.94	$ 195.45	$ (6,909.88)	$ -	$ 16.39	$ 77.19	$ 22.06	$ 24.20	$ 19.78	$ -	$ 28.17	$ (362.53)	$ (5,223.23)
Tx Oth Inc Tx-FICA Co Portion	$ 20,847.88	$ 11,550.64	$ 112,978.29	$ (24,657.17)	$ 51,770.29	$ 33,932.31	$ 18,045.30	$ 14,622.30	$ 30,500.85	$ 25,629.71	$ 40,774.16	$ 34,333.62	$ 370,328.18
Company FICA	$ 20,847.88	$ 11,550.64	$ 112,978.29	$ (24,657.17)	$ 51,770.29	$ 33,932.31	$ 18,045.30	$ 14,622.30	$ 30,500.85	$ 25,629.71	$ 40,774.16	$ 34,333.62	$ 370,328.18
Tx Oth Inc Tx-St Unempl Tax	$ 2,651.57	$ 1,530.28	$ 196.98	$ -	$ -	$ 152.55	$ 38.91	$ 33.28	$ 58.53	$ 24.65	$ 39.72	$ 209.93	$ 4,936.40
State Unemployment	$ 2,651.57	$ 1,530.28	$ 196.98	$ -	$ -	$ 152.55	$ 38.91	$ 33.28	$ 58.53	$ 24.65	$ 39.72	$ 209.93	$ 4,936.40
Tx Oth Inc Tx-Mun Op Prop	$ 221,160.66	$ 220,833.11	$ 220,833.11	$ 220,833.10	$ 220,833.11	$ 220,833.10	$ 220,833.11	$ 220,888.90	$ 220,833.10	$ 220,833.10	$ 220,833.11	$ 483,680.57	$ 2,913,228.08
Municipal Property Tax	$ 221,160.66	$ 220,833.11	$ 220,833.11	$ 220,833.10	$ 220,833.11	$ 220,833.10	$ 220,833.11	$ 220,888.90	$ 220,833.10	$ 220,833.10	$ 220,833.11	$ 483,680.57	$ 2,913,228.08
Franchise Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Taxes Other than Income Taxes	$ 246,326.05	$ 234,109.48	$ 327,098.50	$ 196,175.93	$ 272,619.79	$ 254,995.15	$ 238,939.38	$ 235,568.68	$ 251,412.26	$ 246,487.46	$ 261,675.16	$ 517,861.59	$ 3,283,269.43
Tx Oth Inc Tx-NH Bus Profit Tx	$ -	$ -	$ 573,742.24	$ 70,524.45	$ 70,524.38	$ (2,712.25)	$ 47,344.51	$ (180,338.85)	$ (8,191.28)	$ 1,807.83	$ 1,807.84	$ (6,074.08)	$ 568,434.79
Inc Tx-St Fran MA	$ 2,105.02	$ 375,158.85	$ (390,644.32)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (13,380.45)
Inc Tx-St Fran-Prior Year	$ -	$ -	$ (41,313.00)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (41,313.00)
Current State Income Taxes	$ 2,105.02	$ 375,158.85	$ 141,784.92	$ 70,524.45	$ 70,524.38	$ (2,712.25)	$ 47,344.51	$ (180,338.85)	$ (8,191.28)	$ 1,807.83	$ 1,807.84	$ (6,074.08)	$ 513,741.34
Def SIT Expense-Debit	$ (13,014.61)	$ 12,291.07	$ 249,377.73	$ 43,841.77	$ 5,804.40	$ 95,712.18	$ 45,023.43	$ 96,823.68	$ (14,991.86)	$ 81,374.97	$ 51,815.97	$ 63,323.50	$ 717,382.23
Def SIT Expense-Prior Year	$ -	$ -	$ 17,577.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,577.00
Deferred State Income Taxes-DR	$ (13,014.61)	$ 12,291.07	$ 266,954.73	$ 43,841.77	$ 5,804.40	$ 95,712.18	$ 45,023.43	$ 96,823.68	$ (14,991.86)	$ 81,374.97	$ 51,815.97	$ 63,323.50	$ 734,959.23
Def SIT Expense-Credit	$ (13,236.36)	$ (17,402.78)	$ (296,003.88)	$ (37,747.65)	$ 2,511.89	$ 24,151.83	$ 5,739.69	$ 1,121.38	$ (91,686.27)	$ (7,018.60)	$ (5,363.15)	$ (10,031.48)	$ (444,965.38)
Deferred State Income Taxes-CR	$ (13,236.36)	$ (17,402.78)	$ (296,003.88)	$ (37,747.65)	$ 2,511.89	$ 24,151.83	$ 5,739.69	$ 1,121.38	$ (91,686.27)	$ (7,018.60)	$ (5,363.15)	$ (10,031.48)	$ (444,965.38)
Fed Inc Tx-Current Year	$ -	$ -	$ 11,732.01	$ -	$ -	$ (13,928.71)	$ -	$ -	$ 3,194.51	$ -	$ -	$ (29,696.21)	$ (28,698.40)
Fed Inc Tx-Utility Operations	$ 123,568.50	$ 46,886.94	$ (811,790.71)	$ (3,917.07)	$ (98,306.39)	$ (378,901.55)	$ (226,873.99)	$ (132,684.12)	$ 507,325.68	$ (292,069.69)	$ (451,828.65)	$ (313,011.83)	$ (2,031,602.88)
Fed Inc Tx-Prior Years	$ -	$ -	$ (1,697,868.89)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,393,965.10	$ (303,903.79)
Current Federal Income Taxes	$ 123,568.50	$ 46,886.94	$ (2,497,927.59)	$ (3,917.07)	$ (98,306.39)	$ (392,830.26)	$ (226,873.99)	$ (132,684.12)	$ 510,520.19	$ (292,069.69)	$ (451,828.65)	$ 1,051,257.06	$ (2,364,205.07)
Def FIT Expense-Debit	$ 16,668.45	$ 113,469.56	$ 901,796.44	$ 237,798.25	$ 80,917.71	$ 449,999.47	$ 242,225.21	$ 482,430.97	$ (188,637.11)	$ 383,728.24	$ 262,014.72	$ 307,405.05	$ 3,289,816.96
Def FIT Expense-Prior Year	$ 5,414.00	$ -	$ 1,691,717.89	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,396,266.40)	$ 300,865.49
Deferred Fed Income Taxes-DR	$ 22,082.45	$ 113,469.56	$ 2,593,514.33	$ 237,798.25	$ 80,917.71	$ 449,999.47	$ 242,225.21	$ 482,430.97	$ (188,637.11)	$ 383,728.24	$ 262,014.72	$ (1,088,861.35)	$ 3,590,682.45

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Def FIT Expense-Credit	$ (54,502.64)	$ (71,658.53)	$ (713,304.71)	$ (155,431.49)	$ 9,821.42	$ 61,011.96	$ 8,154.41	$ (29,663.41)	$ (340,085.72)	$ (54,924.89)	$ (47,412.29)	$ (57,405.44)	$ (1,445,401.33)
Deferred Fed Income Taxes-CR	$ (54,502.64)	$ (71,658.53)	$ (713,304.71)	$ (155,431.49)	$ 9,821.42	$ 61,011.96	$ 8,154.41	$ (29,663.41)	$ (340,085.72)	$ (54,924.89)	$ (47,412.29)	$ (57,405.44)	$ (1,445,401.33)
ITC Adjustment-Amort	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,121.00)	$ (2,863.00)	$ (37,854.00)
Investment Tax Credit Adj	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,187.00)	$ (3,121.00)	$ (2,863.00)	$ (37,854.00)
Current Tax-Exceptional Items	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Tax-Exceptional Items	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gain/Loss Dispos of Util Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ARO-Accretion Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OPERATING EXPENSES	**$ 7,554,791.61**	**$ 6,828,508.59**	**$ 7,912,453.20**	**$ 5,985,275.51**	**$ 6,133,503.24**	**$ 7,082,337.10**	**$ 7,345,022.60**	**$ 7,370,752.80**	**$ 6,912,258.69**	**$ 5,612,701.54**	**$ 6,145,503.11**	**$ 7,637,216.58**	**$ 82,520,324.57**
NET OPERATING INCOME	**$ 259,153.92**	**$ 249,504.63**	**$ (1,030,353.52)**	**$ 226,855.03**	**$ 77,089.38**	**$ 306,094.35**	**$ 130,856.18**	**$ 693,474.52**	**$ 46,397.11**	**$ 156,082.17**	**$ (325,610.90)**	**$ (66,144.67)**	**$ 723,398.20**
OTHER INCOME AND DEDUCTIONS													
Allow Oth Funds Used Dur Cons	$ 8,940.58	$ 8,055.08	$ 8,091.05	$ 10,025.41	$ 8,204.61	$ (10,882.50)	$ 8,049.90	$ 8,433.62	$ 9,016.06	$ 7,682.07	$ 10,262.21	$ 9,039.39	$ 84,917.48
Allow Oth Funds Used Dur Cons	$ 8,940.58	$ 8,055.08	$ 8,091.05	$ 10,025.41	$ 8,204.61	$ (10,882.50)	$ 8,049.90	$ 8,433.62	$ 9,016.06	$ 7,682.07	$ 10,262.21	$ 9,039.39	$ 84,917.48
Equity in Earnings of Subs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Income & Deductions													
Income Taxes													
Fed Inc Tx-Nonutility Oper	$ -	$ -	$ 11,732.01	$ -	$ -	$ (13,928.71)	$ -	$ -	$ 3,194.51	$ -	$ -	$ (29,696.21)	$ (28,698.40)
Current Federal	$ -	$ -	$ 11,732.01	$ -	$ -	$ (13,928.71)	$ -	$ -	$ 3,194.51	$ -	$ -	$ (29,696.21)	$ (28,698.40)
Def FIT Exp-Other Oper-Debit	$ -	$ -	$ (8,923.45)	$ -	$ -	$ 13,506.27	$ -	$ -	$ 1,168.55	$ -	$ -	$ 27,481.18	$ 33,232.55
Deferred Federal	$ -	$ -	$ (8,923.45)	$ -	$ -	$ 13,506.27	$ -	$ -	$ 1,168.55	$ -	$ -	$ 27,481.18	$ 33,232.55
St Inc Tx-Nonutility Oper	$ -	$ -	$ 5,608.18	$ -	$ -	$ (3,696.93)	$ -	$ -	$ 847.89	$ -	$ -	$ (7,881.91)	$ (5,122.77)
Current State	$ -	$ -	$ 5,608.18	$ -	$ -	$ (3,696.93)	$ -	$ -	$ 847.89	$ -	$ -	$ (7,881.91)	$ (5,122.77)
Def SIT Exp-Other Oper-Debit	$ -	$ -	$ (1,570.94)	$ -	$ -	$ 3,584.81	$ -	$ -	$ 310.14	$ -	$ -	$ 7,294.00	$ 9,618.01
Deferred State	$ -	$ -	$ (1,570.94)	$ -	$ -	$ 3,584.81	$ -	$ -	$ 310.14	$ -	$ -	$ 7,294.00	$ 9,618.01
Income Taxes	$ -	$ -	$ 6,845.80	$ -	$ -	$ (534.56)	$ -	$ -	$ 5,521.09	$ -	$ -	$ (2,802.94)	$ 9,029.39
NGT Share Awards	$ (16,000.00)	$ -	$ (4,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (146,000.00)
Nonutility Operations	$ (16,000.00)	$ -	$ (4,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (14,000.00)	$ (146,000.00)
Non-Operating Rental Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Municipal & Other Taxes	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rabbi Dividends	$ 493.23	$ 970.97	$ 611.29	$ 597.65	$ 1,048.38	$ 605.12	$ 460.89	$ 952.19	$ 757.40	$ 598.64	$ 943.35	$ 883.50	$ 8,922.61
Dividends	$ 493.23	$ 970.97	$ 611.29	$ 597.65	$ 1,048.38	$ 605.12	$ 460.89	$ 952.19	$ 757.40	$ 598.64	$ 943.35	$ 883.50	$ 8,922.61
Int&Div Inc-Temp Cash Invest	$ 465.36	$ 379.55	$ 404.23	$ 315.88	$ 264.41	$ 241.60	$ 178.34	$ 174.87	$ 204.40	$ 302.64	$ 379.86	$ 394.16	$ 3,705.30
Temp Cash Investments	$ 465.36	$ 379.55	$ 404.23	$ 315.88	$ 264.41	$ 241.60	$ 178.34	$ 174.87	$ 204.40	$ 302.64	$ 379.86	$ 394.16	$ 3,705.30
Interest & Dividend Income	$ 745.98	$ 600.68	$ 723.79	$ 516.31	$ 436.87	$ 503.94	$ 286.76	$ 441.84	$ 503.21	$ 313.00	$ 277.31	$ 320.50	$ 5,670.19
M Pool Int Inc-Assoc Co	$ 348.59	$ 362.34	$ 395.54	$ 709.53	$ 371.41	$ 234.56	$ 208.63	$ 210.06	$ 177.20	$ 211.24	$ 244.57	$ 383.99	$ 3,857.66
Money Pool Interest Income	$ 1,094.57	$ 963.02	$ 1,119.33	$ 1,225.84	$ 808.28	$ 738.50	$ 495.39	$ 651.90	$ 680.41	$ 524.24	$ 521.88	$ 704.49	$ 9,527.85
Interest Income	$ 8,558.50	$ 8,473.36	$ (50,979.80)	$ 15,533.81	$ 12,551.39	$ 12,412.46	$ 12,662.74	$ 12,765.76	$ 13,510.69	$ 13,292.39	$ 22,270.43	$ 19,245.70	$ 100,297.43
Int&Div Inc-Rabbi Trust	$ 2,430.19	$ 2,218.98	$ 3,570.66	$ 1,765.76	$ 2,607.76	$ 2,408.43	$ 2,056.13	$ 3,137.45	$ 2,159.73	$ 2,445.12	$ 2,086.61	$ 2,119.47	$ 29,006.29
Other Int Inc-Refunds	$ (9.75)	$ (9.03)	$ (9.97)	$ (9.38)	$ (8.77)	$ (7.66)	$ (8.14)	$ (8.28)	$ (10.27)	$ (12.16)	$ (13.46)	$ (16.93)	$ (123.80)
Other Interest Income	$ 10,978.94	$ 10,683.31	$ (47,419.11)	$ 17,290.19	$ 15,150.38	$ 14,813.23	$ 14,710.73	$ 15,894.93	$ 15,660.15	$ 15,725.35	$ 24,343.58	$ 21,348.24	$ 129,179.92
Investment Tax Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Discontinued Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Misc Non-Operating Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Group Tax Relief Adj Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Exchange Gains & Losses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Realized Gn/Ls on Dfd Comp Inv	$ 3,158.15	$ (1,579.07)	$ (556.81)	$ 3,298.00	$ (472.56)	$ 6,895.95	$ (402.15)	$ (610.42)	$ (1,621.87)	$ 3,111.43	$ 792.03	$ 115.92	$ 12,128.60
Realized Gn/Ls on Def Comp Inv	$ 3,158.15	$ (1,579.07)	$ (556.81)	$ 3,298.00	$ (472.56)	$ 6,895.95	$ (402.15)	$ (610.42)	$ (1,621.87)	$ 3,111.43	$ 792.03	$ 115.92	$ 12,128.60
Gain on Disp of Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Loss on Disp of Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Impairment of Assets-Oper	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Miscellaneous Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
Other Income Deductions													
Dividend Income-Parent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Donations	$ (1,146.60)	$ (1,160.99)	$ 893.39	$ (137.43)	$ (882.24)	$ (168.08)	$ (1,276.31)	$ (5,173.81)	$ (144.33)	$ (1,299.16)	$ (398.34)	$ (18.90)	$ (10,912.80)
Donations	$ (1,146.60)	$ (1,160.99)	$ 893.39	$ (137.43)	$ (882.24)	$ (168.08)	$ (1,276.31)	$ (5,173.81)	$ (144.33)	$ (1,299.16)	$ (398.34)	$ (18.90)	$ (10,912.80)
Civic & Political Activity	$ (6,283.51)	$ (8,320.01)	$ (61,211.41)	$ (7,311.99)	$ (11,219.57)	$ (8,904.86)	$ (8,373.00)	$ (18,786.31)	$ (10,419.40)	$ (10,295.11)	$ (3,672.55)	$ (3,694.85)	$ (158,492.57)
Civic & Political Activity	$ (6,283.51)	$ (8,320.01)	$ (61,211.41)	$ (7,311.99)	$ (11,219.57)	$ (8,904.86)	$ (8,373.00)	$ (18,786.31)	$ (10,419.40)	$ (10,295.11)	$ (3,672.55)	$ (3,694.85)	$ (158,492.57)
Def Comp Inv-Life Ins	$ (4,472.76)	$ (8,712.35)	$ 23,528.75	$ (2,669.75)	$ (5,664.44)	$ (1,561.32)	$ 1,049.19	$ (434.62)	$ (1,803.14)	$ 2,485.29	$ (6,986.58)	$ (1,155.59)	$ (6,397.32)
Other Deductions	$ -	$ -	$ (23.31)	$ -	$ (5.40)	$ (55.34)	$ (14.85)	$ (12.82)	$ (1,808.65)	$ (189.34)	$ (13.05)	$ (7,167.10)	$ (9,289.86)
Other Deductions	$ (4,472.76)	$ (8,712.35)	$ 23,505.44	$ (2,669.75)	$ (5,669.84)	$ (1,616.66)	$ 1,034.34	$ (447.44)	$ (3,611.79)	$ 2,295.95	$ (6,999.63)	$ (8,322.69)	$ (15,687.18)
Service Co Net Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Income Deductions	$ (11,902.87)	$ (18,193.35)	$ (36,812.58)	$ (10,119.17)	$ (17,771.65)	$ (10,689.60)	$ (8,614.97)	$ (24,407.56)	$ (14,175.52)	$ (9,298.32)	$ (11,070.52)	$ (12,036.44)	$ (185,092.55)
Other Income & Deductions	$ (11,712.62)	$ (6,775.57)	$ (79,807.85)	$ (1,391.61)	$ (14,972.76)	$ (1,929.76)	$ (7,171.77)	$ (21,344.09)	$ (6,973.94)	$ (3,036.02)	$ 1,910.18	$ (5,393.07)	$ (158,598.88)
Equity in Minority Interest	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OTHER INCOME AND DEDUCTIONS	**$ (2,772.04)**	**$ 1,279.51**	**$ (71,716.80)**	**$ 8,633.80**	**$ (6,768.15)**	**$ (12,812.26)**	**$ 878.13**	**$ (12,910.47)**	**$ 2,042.12**	**$ 4,646.05**	**$ 12,172.39**	**$ 3,646.32**	**$ (73,681.40)**
INCOME BEFORE INTEREST CHARGES	**$ 256,381.88**	**$ 250,784.14**	**$ (1,102,070.32)**	**$ 235,488.83**	**$ 70,321.23**	**$ 293,282.09**	**$ 131,734.31**	**$ 680,564.05**	**$ 48,439.23**	**$ 160,728.22**	**$ (313,438.51)**	**$ (62,498.35)**	**$ 649,716.80**
INTEREST CHARGES													
Interest on LTD	$ 94,208.33	$ 94,208.27	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 1,130,499.90
Interest on Long Term Debt	$ 94,208.33	$ 94,208.27	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 94,208.33	$ 1,130,499.90
Amort Debt Disc & Exp	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 2,619.12
Amort of Bond Discount & Exp	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 218.26	$ 2,619.12
Amort of Bond Premium	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amort of Gain/Loss Reacq Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Int Debt to Assoc-MP-Exp	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61.27	$ -	$ -	$ -	$ -	$ 61.27
Interest on Debt to Assoc Cos	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61.27	$ -	$ -	$ -	$ -	$ 61.27
Other Interest Expense	$ 4,503.38	$ 4,459.93	$ (3,511.44)	$ 6,020.23	$ 5,516.56	$ 6,266.35	$ 6,482.58	$ 6,607.46	$ 6,800.61	$ 6,780.82	$ 6,774.41	$ 9,041.70	$ 65,742.59
Oth Int Exp-Tax	$ 7,417.00	$ 7,417.00	$ (26,551.64)	$ 5,890.00	$ 5,890.00	$ 5,853.00	$ 6,208.00	$ 6,208.00	$ 2,578.00	$ 6,261.00	$ 6,261.00	$ 6,261.00	$ 39,692.36
Other Interest Expenses	$ 11,920.38	$ 11,876.93	$ (30,063.08)	$ 11,910.23	$ 11,406.56	$ 12,119.35	$ 12,690.58	$ 12,815.46	$ 9,378.61	$ 13,041.82	$ 13,035.41	$ 15,302.70	$ 105,434.95
Allow Brwd Funds Dur Const-CR	$ (1,777.34)	$ (1,603.90)	$ 3,870.01	$ (1,993.95)	$ (1,631.55)	$ 2,161.76	$ (1,572.47)	$ (1,647.36)	$ (1,760.97)	$ (1,502.37)	$ (2,002.69)	$ (1,086.71)	$ (10,547.54)
Allow Brwd Funds Dur Con-CR	$ (1,777.34)	$ (1,603.90)	$ 3,870.01	$ (1,993.95)	$ (1,631.55)	$ 2,161.76	$ (1,572.47)	$ (1,647.36)	$ (1,760.97)	$ (1,502.37)	$ (2,002.69)	$ (1,086.71)	$ (10,547.54)
TOTAL INTEREST CHARGES	**$ 104,569.63**	**$ 104,699.56**	**$ 68,233.52**	**$ 104,342.87**	**$ 104,201.60**	**$ 108,707.70**	**$ 105,544.70**	**$ 105,655.96**	**$ 102,044.23**	**$ 105,966.04**	**$ 105,459.31**	**$ 108,642.58**	**$ 1,228,067.70**
NET INCOME / (LOSS)	**$ 151,812.25**	**$ 146,084.58**	**$ (1,170,303.84)**	**$ 131,145.96**	**$ (33,880.37)**	**$ 184,574.39**	**$ 26,189.61**	**$ 574,908.09**	**$ (53,605.00)**	**$ 54,762.18**	**$ (418,897.82)**	**$ (171,140.93)**	**$ (578,350.90)**
Preferred Dividends	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Preferred Dividends of Subs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(Gain)/Loss on Preferred Stock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Extraordinary Items	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NET INCOME AVAILABLE FOR COMMON	**$ 151,812.25**	**$ 146,084.58**	**$ (1,170,303.84)**	**$ 131,145.96**	**$ (33,880.37)**	**$ 184,574.39**	**$ 26,189.61**	**$ 574,908.09**	**$ (53,605.00)**	**$ 54,762.18**	**$ (418,897.82)**	**$ (171,140.93)**	**$ (578,350.90)**

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(2) Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;

Please see Company's response to 1604.01(a) (25.02) for Algonquin Power & Utilities Corp. Annual Reports to Shareholders for the years 2010 and 2011.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(3) Federal income tax reconciliation for the test year;

Please see the attached federal income tax reconciliation for Granite State Electric Company for the test year.

Granite State Electric Company
Federal Income Tax Gross-up Factor for Revenue Requirement
For Test Year 2012

Line	Description	Reference	Rate	Factor
1	Federal income tax rate		35.00%	
2				
3				
4	Gross-up for Income Tax	1 / (1- Line 1)		1.5385

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(4) A detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;

Please refer to the attached Computation of Gross-Up Factor for Revenue Requirement.

Granite State Electric Company
Computation of Gross-up Factor for Revenue Requirement
For Test Year 2012

Line	Description	Reference	Rate	Factor
1	Federal income tax rate		35.00%	
2	New Hampshire state income tax rate		8.50%	
3	Combined income tax rate	Line 1 + Line 2 - (Line 1 X Line 2)	40.53%	
4	Gross-up for Income Tax	1 / (1- Line 3)		1.6815

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(5) A detailed list of charitable contributions charged in the test year showing donee and the amount according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all contributions shall be reported;

b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all contributions of $1,000 and more shall be reported;

c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all contributions of $2,500 and more shall be reported; and

d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all contributions of $5,000 and more shall be reported; and

e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular charity shall be on a cumulative basis, indicating the number of items comprising the total amount of contribution.

There are no charitable contributions charged in this category that reach the $2,500 threshold which applies to Granite State Electric Company.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(6) A list of advertising charged in the test year above the line showing expenditure by media and by subject matter according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all expenditures shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all expenditures of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all expenditures of $2,500 and more shall be reported; and
d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all expenditures of $5,000 and more shall be reported;

There are no expenses in this category that reach the $2,500 threshold which applies to Granite State Electric Company.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(7) The utility's most recent cost of service study;

The Company cost of service study is attached to the testimony of Howard S. Gorman, Schedule-HSG-3, Attachment 2 - Marginal Cost Study.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(8) The utility's most recent construction budget;

See attached Granite State Electric Company's construction budget for 2013.

LU Capex Category	Project_Description	2013 Rate Category	Sum of LU FY2013 Budget Request Feb 2013
Mandated	01642 6L4 LEBANON ST UG - DARTMOUTH	Base Rates	$5,000
	01659 Granite St Meter Purchases	Base Rates	$185,000
	01660 Granite St Transformer Purchases	Base Rates	$333,000
	01663 GS Storm Program Proj	Base Rates	$190,000
	01665 GSE-Dist-3rd Party Attach Blanket	Base Rates	$116,000
	01668 GSE-Dist-Genl Equip Blanket	Base Rates	$144,000
	01669 GSE-Dist-Land/Land Rights Blanket	Base Rates	$138,000
	01671 GSE-Dist-Meter Blanket	Base Rates	$99,000
	01674 GSE-Dist-Public Require Blanket	Base Rates	$242,000
	01676 GSE-Dist-St Light Blanket	Base Rates	$62,000
	01677 GSE-Dist-Telecomm Blanket	Base Rates	$11,000
	01679 GSE-Dist-Water Heater Blanket	Base Rates	$44,000
	01737 GSE-Dist-Subs Blanket	Base Rates	$211,000
	04462 US Rt 4A DOT Project	Base Rates	$10,000
	11351 NHDOT#13933E Exit 2 Pelham RD in Salem NH	Base Rates	$50,000
	15001 NHOS Broadband Fiber Project	Base Rates	$200,000
	Dartmouth College OH to UGD	Base Rates	$200,000
	Pleasant St. Ext. Rebuild in Salem	Base Rates	$100,000
	Reserve for Public Requirements Unidentified Specifics & Schedule Changes	Base Rates	$110,000
	Pelham Double Rotary NH DOT	Base Rates	$325,000
Mandated Total			$2,775,000
Integrity	01652 NN D-Line Work Found by Insp.	Base Rates	$200,000
	01666 GSE-Dist-Asset Replace Blanket	Base Rates	$213,000
	01667 GSE-Dist-Damage&Failure Blanket	Base Rates	$510,000
	01688 IE - NN UG Structures and Equipment	Base Rates	$25,000
	01691 IE-NN URD Cable Replacement	Future Rate Recovery	$0
	01741 NH ARP Batts/Chargers Repl Prog	Future Rate Recovery	$0
	01748 NH ARP Relay & related	Future Rate Recovery	$0
	01755 NH Small Capital	Base Rates	$50,000
	09282 Hayes Hill URD	Base Rates	$225,000
	09286 Barron Ave- Upgrade 10L4 Tran & Reg	Future Rate Recovery	$0
	09288 Salem Depot#9 Repl 23/13kV Trans	Future Rate Recovery	$0
	11814 Charlestown 32 Dline	Future Rate Recovery	$0
	11815 Charlestown DSub	Future Rate Recovery	$0
	Reserve for Asset Replacement Unidentified Specifics & Schedule Changes (substation)	Future Rate Recovery	$0
	Reserve for Damage/Failure Unidentified Specifics & Schedule Changes	Base Rates	$160,000
	1L4 Replcement Regs.	Post Test Year Plant	$250,000
Integrity Total			$1,633,000
Reliability	01670 GSE-Dist-Load Relief Blanket	Base Rates	$25,000
	01675 GSE-Dist-Reliability Blanket	Base Rates	$133,000
	01682 IE - NN Cutout Replacements	Special Rate Mechanism	$5,000
	01683 IE - NN Dist Transformer Upgrades	Base Rates	$50,000
	01686 IE - NN Recloser Installations	Special Rate Mechanism	$230,000
	01759 PS&I Activity - New Hampshire	Base Rates	$5,000
	01766 Slaton Hill Sub- Add new Cap Bank	Base Rates	$250,000
	04368 Mt Support-New 16L3 Feeder	Base Rates	$20,000
	04377 Pelham-New 14L4 Fdr	Future Rate Recovery	$0
	04381 Michael Ave Substation	Post Test Year Plant	$2,900,000
	04383 Craft HIllSub- New 11L1 Regs	Post Test Year Plant	$255,000
	04384 Hanover Sub-New 6L2 Regs	Post Test Year Plant	$350,000
	04385 Mt Support Sub- New LP Fdr Pos	Base Rates	$50,000
	04386 NEN-NH Electric Fence FY10	Base Rates	$35,000
	04387 Pelham Sub-Add 2nd Xfmr and Fdr Pos	Base Rates	$30,000
	11255 Michael Ave Getaway	Post Test Year Plant	$950,000
	11484 Enfield Supply	Post Test Year Plant	$1,200,000
	12791 Lebanon Study	Future Rate Recovery	$0
	12886 Spicket River Feeder Reclosers	Base Rates	$140,000
	12887 Sherburne Rd, Pelham 3 Phase Extension	Future Rate Recovery	$0
	7L1 Line Regulator Upgrade - Canaan	Post Test Year Plant	$175,000
	Install 23kV Supply Capacitors - Salem	Base Rates	$50,000
	Reserve for Load Relief Unidentified Specifics & Schedule Changes	Future Rate Recovery	-$100,000
	Reserve for Load Relief Unidentified Specifics & Schedule Changes (substation)	Future Rate Recovery	-$150,000
	Reserve for Reliability Unidentified Specifics & Schedule Changes	Future Rate Recovery	-$50,000
	Bare Conductor Replacement	Special Rate Mechanism	$410,000

	01684 IE - NN ERR/Pockets of Poor Perf	Special Rate Mechanism	$100,000
	12792 Salem Area Study	Future Rate Recovery	$0
Reliability Total			$7,063,000
Growth	01672 GSE-Dist-New Bus-Comm Blanket	Growth	$472,000
	01673 GSE-Dist-New Bus-Resid Blanket	Growth	$539,000
	01705 Pine Tree Cemetary Devl. OH & UG	Growth	$10,000
	11890 Sky View URD - Salem, NH	Growth	$0
	Reserve for New Business Commercial Unidentified Specifics & Schedule Changes	Growth	$110,000
	Whelan Engineering	Growth	$50,000
Growth Total			$1,181,000
Non-Infrastructure	Customer Walk In Centers (Salem & Lebanon)	Post Test Year Plant	$0
	Misc Capital Improvements GSE (Estimated)(4)	Post Test Year Plant	$400,000
	Refreshing Existing Buildings GSE(Capital Aspect)(3)	Post Test Year Plant	$400,000
	Security Conversion GSE	Post Test Year Plant	$82,500
	Purchase Londonderry - GSE Allocation	Future Rate Recovery	$577,500
	Upfit Londonderry - GSE Allocation	Future Rate Recovery	$479,655
	9 Lowell Rd. Salem Build Out	Post Test Year Plant	$500,000
	IT	Future Rate Recovery	$2,424,383
	Vehicle Purchases - BR	Base Rates	$830,500
	Vehicle Purchases - PTYP	Post Test Year Plant	$1,714,500
Non-Infrastructure Total			$7,409,038
Grand Total			$20,061,038

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(9) The utility's chart of accounts, if different from the uniform system of accounts established by the commission as part of Puc 300, Puc 400, Puc 500, Puc 600 and Puc 700;

Granite State Electric Company uses the FERC Uniform System of Accounts, pursuant to Puc 307.04.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(10) The utility's Securities and Exchange Commission 10K forms and 10Q forms, for the most recent 2 years;

Please see Puc 1604.01(a) (25.10) for Algonquin Power & Utilities Corp.'s Form 40-F to the United States Securities and Exchange Commission for the years ended December 31, 2010 and 2011.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(11) A detailed list of all membership fees, dues, and donations for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount according to the following guidelines:

a. If the utility's annual gross revenues are less than $100,000, all membership fees, dues and donations shall be reported;
b. If the utility's annual gross revenues are $100,000 or are between $100,000 and $10,000,000, all membership fees, dues and donations of $1,000 and more shall be reported;
c. If the utility's annual gross revenues are $10,000,000 or are between $10,000,000 and $100,000,000, all membership fees, dues and donations of $2,500 and more shall be reported; and
d. If the utility's annual gross revenues are $100,000,000 or are in excess of $100,000,000, all membership fees, dues and donations of $5,000 and more shall be reported;

There are no membership fees, dues and donations charged in this category that reach the $2,500 threshold which applies to Granite State Electric Company.

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Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(12) A list of any management audit and depreciation studies performed within the last 5 years, specifying whether same are on file with the commission;

See Granite State Electric Company's witness Dane A. Watson's pre-filed direct testimony for the Company's depreciation study dated December 31, 2011 (Attachment DAW-2). There have been no management audits in the past 5 years.

(13) Copies of any audits or studies referred to in (12) above which the utility has not submitted to the commission;

See 1604.01(a) (12).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(14) A list of officers and directors of the utility and their compensation for the last 2 years;

Please see attached for a list of officers and directors of Granite State Electric Company and their compensation for the last 2 years.

Granite State Electric Company was purchased by Liberty Energy Utilities (New Hampshire) Corp. ("Liberty Energy NH") on July 3, 2012. The following table lists the total annual compensation for the officers and directors of Granite State Electric Company for calendar years 2012 and 2013 under Liberty Energy NH's ownership.

Granite State Electric Company
Officers as of 07/03/12 and 01/22/13
Compensation as of 07/03/12 and 2013

REDACTED

		2012				
Name	Title	Base Salary as of July 3, 2012	Appointment Date	Resignation Date	Annual Award Paid June 2012	Total Direct Compensation
Ian E. Robertson	Chairman of the Board	$419,425.00	3-Jul-12		$349,508.00	$768,933.00
Gregory S. Sorensen	Director	Redacted	3-Jul-12		Redacted	Redacted
Victor Del Vecchio	President	Redacted	3-Jul-12		$0.00	Redacted
David Bronicheski	Secretary/Treasurer	$267,500.00	3-Jul-12		$280,488.00	$547,988.00

		2013				
Name	Title	Base Salary	Appointment Date	Resignation Date	Annual Award Paid	Total Direct Compensation
Ian E. Robertson	Chief Executive Officer and Chairman of the Board	Redacted	22-Jan-13		$0.00	Redacted
Gregory S. Sorensen	Director	Redacted	22-Jan-13		$0.00	Redacted
Victor Del Vecchio	President	Redacted	22-Jan-13		$0.00	Redacted
David Bronicheski	Secretary/Treasurer	Redacted	22-Jan-13		$0.00	Redacted
Christopher Jaratt	Vice President	Redacted	22-Jan-13		$0.00	Redacted

Note: Liberty Energy Utilities (New Hampshire) Corp. acquired Granite State on July 3, 2012
Note: Victor Del Vecchio joined the company in Jan 2012, therefore was not eligible for a 2011 performance bonus paid in 2012
Note: Bonuses for 2012 have not yet been paid out, expected in June 2013

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(15) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;
b. Owned by the spouse or minor child of an officer or director; or
c. Controlled by the officer or director directly or indirectly;

All of the stock of Grate State Electric Company is owned by Liberty Energy Utilities (New Hampshire) Corp. ("Liberty Energy NH"), and thus there is no voting stock owned by any of the Company's officers and directors.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(16) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $100,000 in annual gross revenues, a list of all payments in excess of $1,000; and

b. For utilities with annual gross revenues of $100,000 or between $100,000 and $10,000,000, a list of all payments in excess of $10,000;

c. For utilities with annual gross revenues of $10,000,000 or between $10,000,000 and $100,000,000, a list of all payments in excess of $50,000;

d. For utilities with annual gross revenues of $100,000,000 or in excess of $100,000,000, a list of all payments in excess of $100,000; and

e. For utilities in categories b., c. and d. above, the reporting thresholds for a particular entity shall be on a cumulative basis, indicating the number of items comprising the total amount of expenditure.

Please see attached schedule of contractual payments paid by Granite State Electric Company in excess of $50,000 during the test year.

Granite State Electric Company
List of Contractual Services
For Test Year 2012

	Vendor Name	Description	Payment Amount	Qty of Invoices
1	Balance Staffing	Staffing Support	$68,871.54	3
2	Algonquin Power & Utilities Corp.	Corporate Support Services	$93,175.91	3
3	National Grid	Transition Service Agreement	$968,929.56	5

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(17) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations;

There are no non-utility assets or related costs allocated for Granite State Electric Company.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(18) Balance sheets and income statements for the previous 3 years;

Please see attached balance sheets and income statements for Granite State Electric Company for 2009, 2010 and 2011.

- Attachment 1 – 2009
- Attachment 2 – 2010
- Attachment 3 – 2011

Granite State Electric Company
Comparative Balance Sheet & Income Statement
2009/Q4

Puc 1604.01(a) (18)
Attachment 1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2010	End of 2009/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	142,254,266	138,315,082
3	Construction Work in Progress (107)	200-201	2,923,186	1,304,340
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		145,177,452	139,619,422
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	50,688,590	47,886,061
6	Net Utility Plant (Enter Total of line 4 less 5)		94,488,862	91,733,361
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		94,488,862	91,733,361
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		32,086	32,086
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		27,045	27,905
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		995,861	805,440
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,054,992	865,431
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		217,338	510,726
36	Special Deposits (132-134)		3,070,049	70,049
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		8,536,282	11,599,773
41	Other Accounts Receivable (143)		555,774	383,569
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		597,427	352,196
43	Notes Receivable from Associated Companies (145)		0	5,225,000
44	Accounts Receivable from Assoc. Companies (146)		2,158,678	1,138,700
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	447,265	311,120
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2010	End of 2009/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	-51,017	-13,244
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		8,639,386	1,815,294
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		152	6,334
60	Rents Receivable (172)		264	10
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		16,098	11,995
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		22,992,842	20,707,130
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		37,256	39,875
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	3,316,288	1,961,892
73	Prelim. Survey and Investigation Charges (Electric) (183)		105,268	160,113
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-54,039	-59,890
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	7,618	869,064
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		0	0
82	Accumulated Deferred Income Taxes (190)	234	8,125,509	6,187,581
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		11,537,900	9,158,635
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		130,074,596	122,464,557

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	6,040,000	6,040,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	40,053,584	40,053,584
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	32,569,604	33,184,258
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-7,983,597	-5,436,718
16	Total Proprietary Capital (lines 2 through 15)		70,679,591	73,841,124
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	15,000,000	15,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		15,000,000	15,000,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		0	0
29	Accumulated Provision for Pensions and Benefits (228.3)		0	0
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		95,095	93,005
35	Total Other Noncurrent Liabilities (lines 26 through 34)		95,095	93,005
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		6,616,943	7,546,382
39	Notes Payable to Associated Companies (233)		1,275,000	0
40	Accounts Payable to Associated Companies (234)		842,802	713,938
41	Customer Deposits (235)		348,347	335,228
42	Taxes Accrued (236)	262-263	6,185	439,966
43	Interest Accrued (237)		306,041	294,977
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		50,124	39,144
48	Miscellaneous Current and Accrued Liabilities (242)		1,125,217	1,122,535
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		10,570,659	10,492,170
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	215,082	261,310
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	8,298,979	4,994,928
60	Other Regulatory Liabilities (254)	278	2,591,310	2,504,746
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		19,666,645	12,732,296
64	Accum. Deferred Income Taxes-Other (283)		2,957,235	2,544,978
65	Total Deferred Credits (lines 56 through 64)		33,729,251	23,038,258
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		130,074,596	122,464,557

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2010	End of 2009/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	83,885,903	103,787,059		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	71,848,912	89,212,128		
5	Maintenance Expenses (402)	320-323	3,373,362	3,242,927		
6	Depreciation Expense (403)	336-337	4,288,958	4,139,587		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	173	185		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		262,591	262,591		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	2,588,569	2,699,198		
15	Income Taxes - Federal (409.1)	262-263	-7,433,243	-1,578,974		
16	- Other (409.1)	262-263	-170,943	184,936		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	10,379,597	6,703,271		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	2,756,233	3,207,159		
19	Investment Tax Credit Adj. - Net (411.4)	266	-46,228	-53,915		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)			-9,118		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		82,335,515	101,595,657		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,550,388	2,191,402		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2010	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
83,885,903	103,787,059					2
						3
71,848,912	89,212,128					4
3,373,362	3,242,927					5
4,288,958	4,139,587					6
173	185					7
						8
						9
						10
						11
262,591	262,591					12
						13
2,588,569	2,699,198					14
-7,433,243	-1,578,974					15
-170,943	184,936					16
10,379,597	6,703,271					17
2,756,233	3,207,159					18
-46,228	-53,915					19
						20
						21
						22
						23
	-9,118					24
82,335,515	101,595,657					25
1,550,388	2,191,402					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2010	End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,550,388	2,191,402		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		370,500	310,131		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		59,614	280,368		
38	Allowance for Other Funds Used During Construction (419.1)		125,145	76,951		
39	Miscellaneous Nonoperating Income (421)		-27,871	-27,812		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		-213,612	19,376		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		10,564	52,022		
46	Life Insurance (426.2)		13,979	-53,621		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		135,730	196,435		
49	Other Deductions (426.5)			27		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		160,273	194,863		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	-123,200	-47,100		
54	Income Taxes-Other (409.2)	262-263	-29,700	-9,400		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277		-600		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-152,900	-57,100		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-220,985	-118,387		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		84			
68	Other Interest Expense (431)		100,934	243,377		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		23,937	15,573		
70	Net Interest Charges (Total of lines 62 thru 69)		1,210,200	1,360,923		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		119,203	712,092		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		119,203	712,092		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) ☐ An Original (2) ☒ A Resubmission	09/16/2011	End of 2010/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	149,833,746	142,254,266
3	Construction Work in Progress (107)	200-201	1,156,626	2,923,186
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		150,990,372	145,177,452
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	53,698,759	50,688,590
6	Net Utility Plant (Enter Total of line 4 less 5)		97,291,613	94,488,862
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		97,291,613	94,488,862
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		32,086	32,086
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		31,153	27,045
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,079,518	995,861
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,142,757	1,054,992
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		78,866	217,338
36	Special Deposits (132-134)		3,276,112	3,070,049
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		8,660,919	8,536,282
41	Other Accounts Receivable (143)		1,058,591	555,774
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		575,626	597,427
43	Notes Receivable from Associated Companies (145)		5,500,000	0
44	Accounts Receivable from Assoc. Companies (146)		841,897	2,158,678
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	507,521	447,265
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	-13,806	-51,017
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		751,797	8,639,386
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		2,602	152
60	Rents Receivable (172)		64,355	264
61	Accrued Utility Revenues (173)		1,233,000	0
62	Miscellaneous Current and Accrued Assets (174)		28,288	16,098
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		21,414,516	22,992,842
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		34,637	37,256
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	1,868,171	3,316,288
73	Prelim. Survey and Investigation Charges (Electric) (183)		177,081	105,268
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		121,884	-54,039
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	8,556	7,618
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		0	0
82	Accumulated Deferred Income Taxes (190)	234	7,747,982	8,125,509
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		9,958,311	11,537,900
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		129,807,197	130,074,596

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Granite State Electric Company	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	end of 2010/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	6,040,000	6,040,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	40,053,584	40,053,584
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	33,543,272	32,569,604
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-7,310,579	-7,983,597
16	Total Proprietary Capital (lines 2 through 15)		72,326,277	70,679,591
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	15,000,000	15,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		15,000,000	15,000,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		500,000	0
29	Accumulated Provision for Pensions and Benefits (228.3)		0	0
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		111,410	95,095
35	Total Other Noncurrent Liabilities (lines 26 through 34)		611,410	95,095
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		6,617,384	6,616,943
39	Notes Payable to Associated Companies (233)		0	1,275,000
40	Accounts Payable to Associated Companies (234)		964,549	842,802
41	Customer Deposits (235)		326,425	348,347
42	Taxes Accrued (236)	262-263	517,917	6,185
43	Interest Accrued (237)		307,117	306,041
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		39,298	50,124
48	Miscellaneous Current and Accrued Liabilities (242)		2,449,000	1,125,217
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		11,221,690	10,570,659
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	172,595	215,082
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	7,948,637	8,298,979
60	Other Regulatory Liabilities (254)	278	2,387,202	2,591,310
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		18,724,944	19,666,645
64	Accum. Deferred Income Taxes-Other (283)		1,414,442	2,957,235
65	Total Deferred Credits (lines 56 through 64)		30,647,820	33,729,251
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		129,807,197	130,074,596

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	82,898,549	83,885,903		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	69,565,983	71,848,912		
5	Maintenance Expenses (402)	320-323	1,553,221	3,373,362		
6	Depreciation Expense (403)	336-337	4,539,499	4,288,958		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	230	173		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		254,503	262,591		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	2,934,455	2,588,569		
15	Income Taxes - Federal (409.1)	262-263	1,305,655	-7,433,243		
16	- Other (409.1)	262-263	307,136	-170,943		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	846,860	10,379,597		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	560,677	2,756,233		
19	Investment Tax Credit Adj. - Net (411.4)	266	-42,487	-46,228		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		80,704,378	82,335,515		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,194,171	1,550,388		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
82,898,549	83,885,903					2
						3
69,565,983	71,848,912					4
1,553,221	3,373,362					5
4,539,499	4,288,958					6
230	173					7
						8
						9
						10
						11
254,503	262,591					12
						13
2,934,455	2,588,569					14
1,305,655	-7,433,243					15
307,136	-170,943					16
846,860	10,379,597					17
560,677	2,756,233					18
-42,487	-46,228					19
						20
						21
						22
						23
						24
80,704,378	82,335,515					25
2,194,171	1,550,388					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		2,194,171	1,550,388		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		163,000	370,500		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		202,855	59,614		
38	Allowance for Other Funds Used During Construction (419.1)		47,172	125,145		
39	Miscellaneous Nonoperating Income (421)		11,071	-27,871		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		98,098	-213,612		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		23,715	10,564		
46	Life Insurance (426.2)		-23,374	13,979		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		38,748	135,730		
49	Other Deductions (426.5)					
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		39,089	160,273		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	42,600	-123,200		
54	Income Taxes-Other (409.2)	262-263	14,500	-29,700		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-61,170			
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,070	-152,900		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		63,079	-220,985		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		521	84		
68	Other Interest Expense (431)		19,361	100,934		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,556	23,937		
70	Net Interest Charges (Total of lines 62 thru 69)		1,143,445	1,210,200		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,113,805	119,203		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		1,113,805	119,203		

Granite State Electric Company
Comparative Balance Sheet & Income Statement
2011/Q4

Puc 1604.01(a) (18)
Attachment 3

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	153,972,280	149,833,746
3	Construction Work in Progress (107)	200-201	2,226,663	1,156,626
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		156,198,943	150,990,372
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	56,701,087	53,698,759
6	Net Utility Plant (Enter Total of line 4 less 5)		99,497,856	97,291,613
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		99,497,856	97,291,613
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		32,086	32,086
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		36,445	31,153
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		1,104,442	1,079,518
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		1,172,973	1,142,757
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		636,637	78,866
36	Special Deposits (132-134)		3,271,307	3,276,112
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		10,345,549	8,660,919
41	Other Accounts Receivable (143)		1,082,613	1,058,591
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		657,004	575,626
43	Notes Receivable from Associated Companies (145)		2,425,000	5,500,000
44	Accounts Receivable from Assoc. Companies (146)		129,671	841,897
45	Fuel Stock (151)	227	0	0
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	617,980	507,521
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	-10,076	-13,806
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		2,353,992	751,797
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		705	2,602
60	Rents Receivable (172)		231,364	64,355
61	Accrued Utility Revenues (173)		999,000	1,233,000
62	Miscellaneous Current and Accrued Assets (174)		6,367	28,288
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		21,433,105	21,414,516
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		32,018	34,637
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	5,452,728	1,868,171
73	Prelim. Survey and Investigation Charges (Electric) (183)		21,363	177,081
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		-146,119	121,884
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	2,567	8,556
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		0	0
82	Accumulated Deferred Income Taxes (190)	234	6,524,249	7,747,982
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		11,886,806	9,958,311
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		133,990,740	129,807,197

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2011/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	6,040,000	6,040,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	40,053,584	40,053,584
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	33,302,155	33,543,272
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-5,962,261	-7,310,579
16	Total Proprietary Capital (lines 2 through 15)		73,433,478	72,326,277
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	15,000,000	15,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		15,000,000	15,000,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		850,000	500,000
29	Accumulated Provision for Pensions and Benefits (228.3)		0	0
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		111,414	111,410
35	Total Other Noncurrent Liabilities (lines 26 through 34)		961,414	611,410
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		7,693,449	6,617,384
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		878,656	964,549
41	Customer Deposits (235)		653,995	326,425
42	Taxes Accrued (236)	262-263	665,414	517,917
43	Interest Accrued (237)		158,793	307,117
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2011/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		48,485	39,298
48	Miscellaneous Current and Accrued Liabilities (242)		3,804,011	2,449,000
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		13,902,803	11,221,690
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	134,741	172,595
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	6,115,756	7,948,637
60	Other Regulatory Liabilities (254)	278	2,171,409	2,387,202
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		17,466,714	18,724,944
64	Accum. Deferred Income Taxes-Other (283)		4,804,425	1,414,442
65	Total Deferred Credits (lines 56 through 64)		30,693,045	30,647,820
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		133,990,740	129,807,197

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	83,243,723	82,898,549		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	70,044,606	69,565,983		
5	Maintenance Expenses (402)	320-323	3,327,153	1,553,221		
6	Depreciation Expense (403)	336-337	4,788,762	4,539,499		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	236	230		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		239,487	254,503		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	3,283,269	2,934,455		
15	Income Taxes - Federal (409.1)	262-263	-2,294,977	1,305,655		
16	- Other (409.1)	262-263	257,568	307,136		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	4,347,745	846,860		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,772,903	560,677		
19	Investment Tax Credit Adj. - Net (411.4)	266	-37,854	-42,487		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		82,183,092	80,704,378		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,060,631	2,194,171		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
83,243,723	82,898,549					2
						3
70,044,606	69,565,983					4
3,327,153	1,553,221					5
4,788,762	4,539,499					6
236	230					7
						8
						9
						10
						11
239,487	254,503					12
						13
3,283,269	2,934,455					14
-2,294,977	1,305,655					15
257,568	307,136					16
4,347,745	846,860					17
1,772,903	560,677					18
-37,854	-42,487					19
						20
						21
						22
						23
						24
82,183,092	80,704,378					25
1,060,631	2,194,171					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,060,631	2,194,171		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		146,000	163,000		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		151,336	202,855		
38	Allowance for Other Funds Used During Construction (419.1)		84,917	47,172		
39	Miscellaneous Nonoperating Income (421)		12,129	11,071		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		102,382	98,098		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		10,913	23,715		
46	Life Insurance (426.2)		6,397	-23,374		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		158,493	38,748		
49	Other Deductions (426.5)		9,290			
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		185,093	39,089		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	28,698	42,600		
54	Income Taxes-Other (409.2)	262-263	5,123	14,500		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-42,851	-61,170		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-9,030	-4,070		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-73,681	63,079		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		61	521		
68	Other Interest Expense (431)		105,435	19,361		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,548	9,556		
70	Net Interest Charges (Total of lines 62 thru 69)		1,228,067	1,143,445		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		-241,117	1,113,805		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		-241,117	1,113,805		

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(19) Quarterly income statements for the previous 5 years;

Please find attached for Granite State Electric Company, quarterly income statements for the previous five years.

- Attachment 1 – 2007
- Attachment 2 – 2008
- Attachment 3 – 2009
- Attachment 4 – 2010
- Attachment 5 – 2011

Granite State Electric Company
Quarterly Income Statement
2007/Q4

Puc 1604.01(a) (19)
Attachment 1

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	95,949,395	89,013,926		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	79,287,899	71,368,553		
5	Maintenance Expenses (402)	320-323	4,269,999	2,883,669		
6	Depreciation Expense (403)	336-337	3,901,395	3,634,064		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	252	216		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		44,888			
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	1,925,876	2,028,417		
15	Income Taxes - Federal (409.1)	262-263	968,681	2,170,617		
16	- Other (409.1)	262-263	-237,625	-2,328,780		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	4,292,144	5,485,761		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	3,832,009	3,838,838		
19	Investment Tax Credit Adj. - Net (411.4)	266	-52,813	-54,461		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		5,216	3,901		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		90,573,903	81,353,119		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		5,375,492	7,660,807		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/28/2008	End of 2007/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
95,949,395	89,013,926					2
						3
79,287,899	71,368,553					4
4,269,999	2,883,669					5
3,901,395	3,634,064					6
252	216					7
						8
						9
						10
						11
44,888						12
						13
1,925,876	2,028,417					14
968,681	2,170,617					15
-237,625	-2,328,780					16
4,292,144	5,485,761					17
3,832,009	3,838,838					18
-52,813	-54,461					19
						20
						21
						22
						23
5,216	3,901					24
90,573,903	81,353,119					25
5,375,492	7,660,807					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	03/28/2008	End of 2007/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		5,375,492	7,660,807		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		153,905	116,124		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		746,543	857,110		
38	Allowance for Other Funds Used During Construction (419.1)		63,140	72,567		
39	Miscellaneous Nonoperating Income (421)		4,403	8,818		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		660,181	822,371		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			2,668		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	47,719	37,651		
46	Life Insurance (426.2)		17,335	238,861		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		69,785	117,989		
49	Other Deductions (426.5)			5,855		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		134,839	403,024		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	167,400	175,100		
54	Income Taxes-Other (409.2)	262-263	46,800	46,900		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	16,900	76,500		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		231,100	298,500		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		294,242	120,847		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340				
68	Other Interest Expense (431)	340	144,889	25,775		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		13,080	17,420		
70	Net Interest Charges (Total of lines 62 thru 69)		1,264,928	1,141,474		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		4,404,806	6,640,180		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		4,404,806	6,640,180		

Granite State Electric Company
Quarterly Income Statement
2008/Q4

Puc 1604.01(a) (19)
Attachment 2

STATEMENT OF INCOME

Quarterly

1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	103,787,059	95,949,395		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	89,212,128	79,287,899		
5	Maintenance Expenses (402)	320-323	3,242,927	4,269,999		
6	Depreciation Expense (403)	336-337	4,139,587	3,901,395		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	185	252		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		262,591	44,888		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	2,699,198	1,925,876		
15	Income Taxes - Federal (409.1)	262-263	-1,578,974	968,681		
16	- Other (409.1)	262-263	184,936	-237,625		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	6,703,271	4,292,144		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	3,207,159	3,832,009		
19	Investment Tax Credit Adj. - Net (411.4)	266	-53,915	-52,813		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		-9,118	5,216		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		101,595,657	90,573,903		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,191,402	5,375,492		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
103,787,059	95,949,395					2
						3
89,212,128	79,287,899					4
3,242,927	4,269,999					5
4,139,587	3,901,395					6
185	252					7
						8
						9
						10
						11
262,591	44,888					12
						13
2,699,198	1,925,876					14
-1,578,974	968,681					15
184,936	-237,625					16
6,703,271	4,292,144					17
3,207,159	3,832,009					18
-53,915	-52,813					19
						20
						21
						22
						23
-9,118	5,216					24
101,595,657	90,573,903					25
2,191,402	5,375,492					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2009	End of 2008/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		2,191,402	5,375,492		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		310,131	153,905		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		280,368	746,543		
38	Allowance for Other Funds Used During Construction (419.1)		76,951	63,140		
39	Miscellaneous Nonoperating Income (421)		-27,812	4,403		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		19,376	660,181		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	52,022	47,719		
46	Life Insurance (426.2)		-53,621	17,335		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		196,435	69,785		
49	Other Deductions (426.5)		27			
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		194,863	134,839		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	-47,100	167,400		
54	Income Taxes-Other (409.2)	262-263	-9,400	46,800		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-600	16,900		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-57,100	231,100		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-118,387	294,242		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340				
68	Other Interest Expense (431)	340	243,377	144,889		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		15,573	13,080		
70	Net Interest Charges (Total of lines 62 thru 69)		1,360,923	1,264,928		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		712,092	4,404,806		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		712,092	4,404,806		

Granite State Electric Company
Quarterly Income Statement
2009/Q4

Puc 1604.01(a) (19)
Attachment 3

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2010	End of 2009/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	83,885,903	103,787,059		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	71,848,912	89,212,128		
5	Maintenance Expenses (402)	320-323	3,373,362	3,242,927		
6	Depreciation Expense (403)	336-337	4,288,958	4,139,587		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	173	185		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		262,591	262,591		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	2,588,569	2,699,198		
15	Income Taxes - Federal (409.1)	262-263	-7,433,243	-1,578,974		
16	- Other (409.1)	262-263	-170,943	184,936		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	10,379,597	6,703,271		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	2,756,233	3,207,159		
19	Investment Tax Credit Adj. - Net (411.4)	266	-46,228	-53,915		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)			-9,118		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		82,335,515	101,595,657		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,550,388	2,191,402		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
83,885,903	103,787,059					2
						3
71,848,912	89,212,128					4
3,373,362	3,242,927					5
4,288,958	4,139,587					6
173	185					7
						8
						9
						10
						11
262,591	262,591					12
						13
2,588,569	2,699,198					14
-7,433,243	-1,578,974					15
-170,943	184,936					16
10,379,597	6,703,271					17
2,756,233	3,207,159					18
-46,228	-53,915					19
						20
						21
						22
						23
	-9,118					24
82,335,515	101,595,657					25
1,550,388	2,191,402					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,550,388	2,191,402		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		370,500	310,131		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		59,614	280,368		
38	Allowance for Other Funds Used During Construction (419.1)		125,145	76,951		
39	Miscellaneous Nonoperating Income (421)		-27,871	-27,812		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		-213,612	19,376		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		10,564	52,022		
46	Life Insurance (426.2)		13,979	-53,621		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		135,730	196,435		
49	Other Deductions (426.5)			27		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		160,273	194,863		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	-123,200	-47,100		
54	Income Taxes-Other (409.2)	262-263	-29,700	-9,400		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277		-600		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-152,900	-57,100		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-220,985	-118,387		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		84			
68	Other Interest Expense (431)		100,934	243,377		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		23,937	15,573		
70	Net Interest Charges (Total of lines 62 thru 69)		1,210,200	1,360,923		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		119,203	712,092		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		119,203	712,092		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	82,898,549	83,885,903		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	69,565,983	71,848,912		
5	Maintenance Expenses (402)	320-323	1,553,221	3,373,362		
6	Depreciation Expense (403)	336-337	4,539,499	4,288,958		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	230	173		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		254,503	262,591		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	2,934,455	2,588,569		
15	Income Taxes - Federal (409.1)	262-263	1,305,655	-7,433,243		
16	- Other (409.1)	262-263	307,136	-170,943		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	846,860	10,379,597		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	560,677	2,756,233		
19	Investment Tax Credit Adj. - Net (411.4)	266	-42,487	-46,228		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		80,704,378	82,335,515		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		2,194,171	1,550,388		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [ ] An Original (2) [X] A Resubmission	09/16/2011	End of 2010/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
82,898,549	83,885,903					2
						3
69,565,983	71,848,912					4
1,553,221	3,373,362					5
4,539,499	4,288,958					6
230	173					7
						8
						9
						10
						11
254,503	262,591					12
						13
2,934,455	2,588,569					14
1,305,655	-7,433,243					15
307,136	-170,943					16
846,860	10,379,597					17
560,677	2,756,233					18
-42,487	-46,228					19
						20
						21
						22
						23
						24
80,704,378	82,335,515					25
2,194,171	1,550,388					26

Name of Respondent Granite State Electric Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/16/2011	Year/Period of Report End of 2010/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		2,194,171	1,550,388		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		163,000	370,500		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		202,855	59,614		
38	Allowance for Other Funds Used During Construction (419.1)		47,172	125,145		
39	Miscellaneous Nonoperating Income (421)		11,071	-27,871		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		98,098	-213,612		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		23,715	10,564		
46	Life Insurance (426.2)		-23,374	13,979		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		38,748	135,730		
49	Other Deductions (426.5)					
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		39,089	160,273		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	42,600	-123,200		
54	Income Taxes-Other (409.2)	262-263	14,500	-29,700		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-61,170			
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,070	-152,900		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		63,079	-220,985		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		521	84		
68	Other Interest Expense (431)		19,361	100,934		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		9,556	23,937		
70	Net Interest Charges (Total of lines 62 thru 69)		1,143,445	1,210,200		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,113,805	119,203		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		1,113,805	119,203		

Granite State Electric Company
Quarterly Income Statement
2011/Q4

Puc 1604.01(a) (19)
Attachment 5

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Granite State Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	83,243,723	82,898,549		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	70,044,606	69,565,983		
5	Maintenance Expenses (402)	320-323	3,327,153	1,553,221		
6	Depreciation Expense (403)	336-337	4,788,762	4,539,499		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	236	230		
8	Amort. & Depl. of Utility Plant (404-405)	336-337				
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		239,487	254,503		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	3,283,269	2,934,455		
15	Income Taxes - Federal (409.1)	262-263	-2,294,977	1,305,655		
16	- Other (409.1)	262-263	257,568	307,136		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	4,347,745	846,860		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,772,903	560,677		
19	Investment Tax Credit Adj. - Net (411.4)	266	-37,854	-42,487		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		82,183,092	80,704,378		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,060,631	2,194,171		

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
83,243,723	82,898,549					2
						3
70,044,606	69,565,983					4
3,327,153	1,553,221					5
4,788,762	4,539,499					6
236	230					7
						8
						9
						10
						11
239,487	254,503					12
						13
3,283,269	2,934,455					14
-2,294,977	1,305,655					15
257,568	307,136					16
4,347,745	846,860					17
1,772,903	560,677					18
-37,854	-42,487					19
						20
						21
						22
						23
						24
82,183,092	80,704,378					25
1,060,631	2,194,171					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,060,631	2,194,171		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		146,000	163,000		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		151,336	202,855		
38	Allowance for Other Funds Used During Construction (419.1)		84,917	47,172		
39	Miscellaneous Nonoperating Income (421)		12,129	11,071		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		102,382	98,098		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		10,913	23,715		
46	Life Insurance (426.2)		6,397	-23,374		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		158,493	38,748		
49	Other Deductions (426.5)		9,290			
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		185,093	39,089		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	28,698	42,600		
54	Income Taxes-Other (409.2)	262-263	5,123	14,500		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-42,851	-61,170		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-9,030	-4,070		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-73,681	63,079		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		1,130,500	1,130,500		
63	Amort. of Debt Disc. and Expense (428)		2,619	2,619		
64	Amortization of Loss on Reaquired Debt (428.1)					
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		61	521		
68	Other Interest Expense (431)		105,435	19,361		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,548	9,556		
70	Net Interest Charges (Total of lines 62 thru 69)		1,228,067	1,143,445		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		-241,117	1,113,805		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		-241,117	1,113,805		

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(20) Quarterly sales volumes for the previous 5 years, itemized for residential and other classifications of service;

See the attached schedule which shows the quarterly sales volumes for the previous 5 years, itemized for residential and other classifications of service.

Granite State Electric Company
Quarterly Sales Volumes (MWh)
Previous 5 Years - 2008 to 2012

Rate	Q1 Mar-08	Q2 Jun-08	Q3 Sep-08	Q4 Dec-08	TOTAL 2008
D	71,420	59,801	68,612	60,148	259,981
D10	2,066	1,323	1,176	1,324	5,888
G1	60,407	93,663	105,012	80,428	339,510
G2	41,566	38,728	44,092	36,888	161,274
G3	24,597	22,416	25,374	22,043	94,429
M	1,305	1,210	1,225	1,278	5,018
T	8,225	5,011	4,077	5,241	22,554
V	109	77	97	64	348
	209,696	222,229	249,664	207,413	889,002

Rate	Q1 Mar-09	Q2 Jun-09	Q3 Sep-09	Q4 Dec-09	TOTAL 2009
D	74,552	57,546	67,139	61,455	260,693
D10	2,072	1,269	1,135	1,274	5,751
G1	76,422	84,091	87,848	82,690	331,051
G2	38,917	37,169	40,509	36,839	153,434
G3	25,306	21,633	23,569	20,936	91,443
M	1,286	1,243	1,230	1,218	4,977
T	8,339	4,489	3,826	4,965	21,619
V	113	71	84	64	332
	227,007	207,511	225,340	209,441	869,299

Rate	Q1 Mar-10	Q2 Jun-10	Q3 Sep-10	Q4 Dec-10	TOTAL 2010
D	72,733	59,057	77,166	62,516	271,472
D10	2,030	1,163	1,207	1,268	5,668
G1	75,719	84,793	94,399	77,968	332,879
G2	39,238	37,264	44,639	37,335	158,477
G3	23,912	21,310	25,683	21,080	91,985
M	1,282	1,239	1,228	1,211	4,959
T	7,483	4,113	3,907	4,677	20,179
V	115	69	97	66	347
	222,510	209,009	248,327	206,121	885,967

Rate	Q1 Mar-11	Q2 Jun-11	Q3 Sep-11	Q4 Dec-11	TOTAL 2011
D	76,042	61,636	74,224	62,589	274,491
D10	2,080	1,259	1,127	1,182	5,648
G1	82,564	84,174	103,091	84,897	354,726
G2	39,507	38,373	43,894	38,015	159,789
G3	24,487	21,825	24,733	21,474	92,519
M	1,235	1,192	1,163	1,165	4,756
T	7,420	4,357	3,654	4,256	19,687
V	104	71	76	57	308
	233,439	212,886	251,962	213,635	911,923

Rate	Q1 Mar-12	Q2 Jun-12	Q3 Sep-12	Q4 Dec-12	TOTAL 2012
D	73,096	59,430	78,075	62,934	273,535
D10	1,858	1,145	1,226	1,246	5,475
G1	80,945	85,798	109,983	85,420	362,145
G2	38,200	37,236	42,760	35,961	154,157
G3	23,783	21,736	25,485	21,051	92,055
M	1,185	1,162	1,191	1,116	4,654
T	6,549	3,861	3,718	4,334	18,462
V	90	60	80	61	290
	225,705	210,429	262,518	212,122	910,773

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(21) A description of the utility's projected need for external capital for the 2 year period immediately following the test year;

See the attached schedule which shows the utility's projected need for external capital for the 2 year period immediately following the test year.

Projected Sources and Uses of Funds

Line	Description	Note	Year 2013	Year 2014
1	**Sources of Funds**			
2	Cash Flow from Operating Activities:			
3	Net operating income (loss) at current rates		($2,825,260)	
4	Net operating income (loss) at proposed rates			$5,555,684
5	Depreciation expense		5,483,215.98	5,483,215.98
6	Amortization expense	In Accout 924	1,723,648	1,723,648
7	Temporary increase, Net operating income	7/1/13 - 7/1/14	$ 2,725,403	$ 52,439
8	Step increase, Net operating income	Return on rate base		733,734
9	All other Working capital, net		0	0
10	Cash Provided by Operating Activities		**$ 7,107,007**	**$ 13,548,720**
11				
12	Cash Flow from Parent			
13	Long-term debt		$ 5,829,314	$ 621,215
14	Equity		7,124,717	759,263
15	Cash Provided by Financing Activities		**$ 12,954,031**	**$ 1,380,478**
16				
17	**Total Sources of Funds**		**20,061,038**	**14,929,198**
18				
19	**Uses of Funds**			
20	Construction Budget:			
21	Distribution substations		$ 4,471,000	$ 2,921,000
22	Distribution lines		4,327,000	5,719,000
23	Structures and Other		8,718,038	5,240,464
24	Vehicles		2,545,000	315,000
25			$ 20,061,038	$ 14,195,464
26				
27	**Total Uses of Funds**		**$ 20,061,038**	**$ 14,195,464**

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(22) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately subsequent to the test year;

External cash will be required during 2013 in the amount of $12.9 million and during 2014 in the amount of $1.4 million.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(23) The provisions of any sinking funds associated with senior capital and a description of the rate at which any respective issues of senior capital will be retired, consistent with such sinking fund(s);

There are no sinking funds associated with senior capital for Granite State Electric Company.

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(24) If the short-term debt component of total invested capital is volatile, the amount outstanding, on a monthly basis, during the test year, for each short-term indebtedness;

Granite State Electric Company has no short-term debt.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.01) The utility's internal financial reports for the following periods:

a. For the first and last month of the test year;
b. For the entire test year; and
c. For the 12 months or 5 quarters prior to the test year;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.02) Annual reports to stockholders and statistical supplements, if any, for the most recent 5 years;

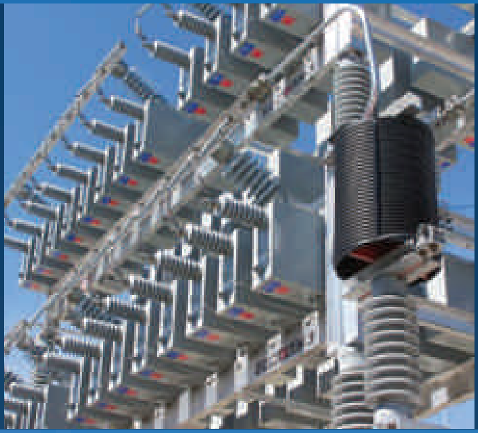
Please see the attached for copies of Algonquin Power & Utilities Corp. Annual Reports to Stockholders for the years 2010 and 2011. Annual reports for calendar years 1997 through 2011 are available at:

http://investors.algonquinpower.com/FinancialDocs.aspx?iid=4142273.

- Attachment 1 – 2010
- Attachment 2 – 2011

Algonquin Power & Utilities Corp.

Annual Financial Results



2010

Table of Contents

ALGONQUIN POWER & UTILITIES

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per share and convertible debenture amounts or where otherwise noted)

Management of Algonquin Power & Utilities Corp. ("APUC"), the corporation continuing the business of Algonquin Power Co. ("Algonquin"), formerly Algonquin Power Income Fund (the "Fund"), has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2010. This Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2010 and 2009. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 2, 2011.

Caution concerning forward-looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "adjusted net earnings" and "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") are used throughout this MD&A. The terms "adjusted net earnings" and Adjusted EBITDA are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). There is no standardized measure of "adjusted net earnings" and Adjusted EBITDA, consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings" and Adjusted EBITDA can be found throughout this MD&A.

Conversion to a Corporation

On October 27, 2009, Algonquin completed a transaction (the “Unit Exchange Offer”) which provided Algonquin’s unitholders the opportunity to exchange their trust units of Algonquin, on a one-for-one basis, for common shares of an existing corporation. This existing corporation, Hydrogenics Corporation, transferred all of its operations and existing shares to a new corporation pursuant to a Plan of Arrangement prior to completion of the Unit Exchange Offer. The name of Hydrogenics Corporation was changed to Algonquin Power & Utilities Corp. following closing of the transaction.

The transaction resulted in the unitholders of Algonquin becoming shareholders of APUC, with no changes to Algonquin’s underlying business operations. Under the continuity of interest method of accounting, APUC’s transfer of assets, liabilities and equity of Algonquin are recorded at their net book value in APUC’s financial statements as at October 27, 2009. As a result of this conversion, certain terms such as shareholder/unitholder and dividend/distribution may be used interchangeably throughout this MD&A. Prior to October 27, 2009, all distributions to unitholders were in the form of trust unit distributions. References to APUC shall mean Algonquin with respect to activities and results occurring prior to October 27, 2009 and shall mean APUC with respect to activities and results occurring on or after October 27, 2009.

Overview

APUC is incorporated under the Canada Business Corporations Act. APUC currently conducts its business primarily through two separate and autonomous subsidiaries: Algonquin Power Co. (“APCo”) owns and operates a diversified portfolio of renewable energy assets and Liberty Utilities Co. (“Liberty Utilities”) owns and operates a portfolio of North American utilities.

APCo generates and sells electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. As at December 31, 2010, APCo owns or has interests in 44 hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds debt securities in a 26 MW wind powered generating station recently completed in Saskatchewan. The renewable energy facilities generally sell their electrical output pursuant to long term power purchase agreements (“PPAs”) with major utilities and have a weighted average remaining contract life of 16 years. Similarly, the 12 thermal energy facilities that APCo has an ownership and interest in operate under PPAs and have a weighted average remaining contract life of 6 years with a combined generating capacity of approximately 210 MW[1].

Liberty Utilities provides utility services related to electricity, natural gas, water and wastewater services. Liberty Water Co. (“Liberty Water”), a subsidiary of Liberty Utilities, provides water and wastewater utility services to approximately 75,000 customers through 19 water distribution and wastewater collection and treatment utility systems located in four U.S. States (Arizona, Illinois, Missouri and Texas). These utilities operate under rate regulation, generally overseen by the public utility commissions of the States in which they operate.

Liberty Energy Utilities Co. (“Liberty Energy”), a subsidiary of Liberty Utilities, provides local electrical and natural gas utility services. On January 1, 2011, in partnership with Emera Inc. (“Emera”), Liberty Energy acquired a California-based electricity distribution utility and related generation assets, and now provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region (the “California Utility”). Liberty Energy has entered into agreements to acquire two additional utilities which currently provide electric and natural gas distribution services to approximately 125,000 customers in New Hampshire.

Business Strategy

APUC’s business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the power and utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through growth in dividends supported

[1] During the fourth quarter, APCo determined that the generating capacity reported for each of its facilities was more appropriately reported based on APCo’s effective percentage ownership interest in the facility, rather than the total installed capacity of the facility; as a result, the generating capacity values set out in respect of some of the facilities included in APCo’s generating portfolio have been reduced from prior periods

by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon APUC strives to deliver annualized per share earnings growth of 5% and to grow its dividend supported by growth in cash flows, earnings and investment prospects.

APUC understands the importance of the dividend to its shareholders. APUC currently pays quarterly cash dividends to shareholders of $0.06 per share or $0.24 per share per annum. On March 3, 2011, the Board of Directors of APUC (the "Board") approved an annual dividend increase of $0.02 per common share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per common share. The Board also declared a dividend of $0.065 per share payable on April 15, 2011 to the shareholders of record on March 31, 2011.

APUC believes this level of dividends will continue to allow for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Any increases in the level of dividends paid by APUC will be at the discretion of the Board and dividend levels shall be reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to the Company. APUC strives to achieve its results within a moderate risk profile consistent with top-quartile North American power and utility operations.

Independent Power: APCo develops, owns and operates a diversified portfolio of electrical energy generation facilities. Within this business there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates APCo's hydroelectric and wind power facilities. The Thermal Energy division operates co-generation, energy-from-waste, and steam production facilities. The Development division seeks to deliver continuing growth to APCo through development of APCo's greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within APCo's existing portfolio of renewable energy and thermal energy facilities.

Utilities: Liberty Utilities owns and operates utilities through its two wholly-owned subsidiaries, Liberty Energy and Liberty Water, in the electricity distribution, transmission and generation as well as natural gas distribution, water distribution and wastewater treatment sectors. These utilities share certain common infrastructure to generate economies of scale to support best-in-class customer care for its utility ratepayers. The underlying business strategy is to be a leading provider of safe, high quality and reliable utility services while providing stable and predictable earnings from its utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings by identifying acquisition opportunities which accretively expand its business portfolio.

Major Highlights

Liberty Water Rate Cases

During the year ended December 31, 2010, Liberty Water completed rate case proceedings at nine utilities in Arizona and Texas which on an annualized basis are expected to contribute an additional U.S. $10.2 million in revenue in Liberty Water. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. $1.1 million in annual revenue requirement is expected to be concluded by the first quarter of 2011.

California Utility Acquisition and Senior Debt Financing

On January 1, 2011, following receipt of all U.S. state and federal regulatory approvals, APUC announced that, in partnership with Emera, Liberty Energy had acquired the assets comprising the California Utility. Liberty Energy owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, California Pacific Electric Company ("Calpeco").

The acquisition of the California Utility was completed for a gross purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. Upon closing, Emera exchanged previously announced subscription receipts into 8.532 million APUC common shares at a purchase price of $3.25 per share. The proceeds of the subscription receipts were utilized to fund Liberty Energy's ownership share of the cost of acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility entered into on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

Granite State/EnergyNorth Acquisition

On December 9th, 2010 APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company ("Granite State"), a regulated electric distribution utility, and EnergyNorth Natural Gas, Inc. ("EnergyNorth"), a regulated natural gas distribution utility from National Grid USA ("National Grid") for total consideration of U.S. $285.0 million.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011. Financing of the acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Energy is targeting a capital structure with not more than 50% debt to total capital, consistent with investment grade utilities. In connection with these acquisitions, Emera has committed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. The issuance of these subscription receipts is subject to regulatory approval.

Red Lily Wind Project

On February 28, 2011 APUC announced that the 26.4 MW wind generation facility in southeastern Saskatchewan ("Red Lily I") commenced commercial operation under the PPA. APUC's commitment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011, such interest payments and fees are expected to be approximately $2.4 million. APUC has the option to formally exchange its debt investment for a 75% equity position in the facility in 2016. See *Renewable Energy - Divisional Outlook* for more discussion of this project.

New Wind Projects Under Development

75 MW Wind - Amherst Island: On February 25, 2011 APUC announced that the Ontario Power Authority ("OPA") awarded a contract to the wholly owned 75 MW Amherst Island Wind Project, located on Amherst Island in the village of Stella, approximately 25 kilometers southwest of Kingston, Ontario. The contract was awarded as part of the second round of the OPA's Feed-in Tariff ("FIT") program.

The project, which will be developed by APCo, is currently contemplated to use more efficient Class III wind turbine generator technology that is estimated to produce approximately 247 GW-hrs of power annually. Funding of the total capital costs, currently estimated to be $220 million, will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 months.

On December 21st, 2010 APUC announced that Hydro-Québec Distribution has accepted proposals for the purchase of energy from the 24 MW Saint-Damase and 24 MW Val-Éo wind power generating projects. The projects were submitted with support from APUC in response to the community based call for offers announced in the spring of 2009.

25MW Wind – Saint-Damase: The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APUC. The first 24 MW phase of the project is currently envisioned to consist of twelve 2 MW ENERCON Canada Inc. ("ENERCON") E-82 wind turbine generators, producing approximately

86,000 MWh annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

25 MW Wind - Val-Éo: The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APUC. The first 24 MW phase of the project is expected to be comprised of eight 3 MW ENERCON E-101 wind turbine generators, producing approximately 66,000 MW-hrs annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interests of APUC in the Saint-Damase and Val- Éo projects is subject to final negotiations with the partners in the projects but, in any event, will not be less than 50% and 25%, respectively. Final funding of the projects will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began for both projects in early 2011, with all major authorizations targeted for completion by the end of 2012.

Credit Facility Renewal

On January 14, 2011 APUC announced that it has received commitments with a syndicate of banks for a new Algonquin Power Co. $142 million senior secured revolving credit Facility ("Facility") with a three year term. The Facility syndicate is being led by National Bank of Canada. The other syndicate members are The Toronto-Dominion Bank, Bank of Montreal, and Canadian Imperial Bank of Commerce.

Liberty Water Senior Debt Financing

On December 22, 2010 Liberty Water entered into a U.S. $50 million private placement debt financing. The notes are senior unsecured with a 10 year term bearing interest at 5.6%. The notes are interest only until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. The funds were used to reduce outstanding indebtedness under APCo's senior credit Facility.

2010 Annual results from operations

Key Selected Annual Financial Information

	Year ended December 31 2010	2009	2008
Revenue	**$ 182,882**	$ 187,265	$ 213,796
Adjusted EBITDA [2]	**$ 75,107**	$ 79,368	90,028
Cash provided by Operating Activities	**45,180**	48,031	77,223
Net earnings	**19,639**	31,257	(19,038)
Adjusted net earnings [3]	**19,915**	30,503	18,788
Dividend/distributions to Shareholders/Unitholders [1]	**22,765**	19,322	57,755
Per share/trust unit			
Net earnings	**$ 0.21**	$ 0.39	(0.25)
Adjusted net earnings [3]	**$ 0.21**	$ 0.38	0.25
Diluted net earnings	**$ 0.21**	$ 0.39	(0.25)
Cash provided by Operating Activities	**$ 0.48**	$ 0.60	1.03
Dividends/distributions to Shareholders/Unitholders	**$ 0.24**	$ 0.24	0.75
Total Assets	**980,917**	1,013,413	978,515
Long Term Debt[4]	**257,429**	241,412	293,590

[1] Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into APCo trust units.
[2] APUC uses Adjusted EBITDA to enhance assessment and understanding of the operating performance of APUC without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted EBITDA is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[3] APUC uses Adjusted net earnings to enhance assessment and understanding of the performance of APUC without the effects of gains or losses on derivative financial instruments which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted net earnings is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[4] Includes the Airsource Senior Debt Financing which matures on October 31, 2011 and has been recorded as a current liability on the consolidated balance sheet.

For the year ended December 31, 2010, APUC reported total revenue of $182.9 million as compared to $187.3 million during the same period in 2009, a decrease of $4.4 million or 2.3%. The major factors resulting in the decrease in APUC revenue in the year ended December 31, 2010 as compared to the corresponding period in 2009, are set out as follows:

	Year ended December 31, 2010
Comparative Prior Period Revenue	$ 187,265
Significant Changes:	
Impact of the stronger Canadian dollar	(10,100)
Impact of shutdown at Energy-from-Waste facility	(5,300)
Effect of hydrology compared to prior year	(4,800)
Change in operating model at Windsor Locks	(3,800)
Closure of land fill gas facilities	(1,100)
Acquisition of Tinker Hydro in Q1 2010	17,800
Red Lily I – development, construction and supervision fees	2,100
Liberty Water revenue increases primarily due to rate case approvals	2,800
All Other	(1,983)
Current Period Revenue	$ 182,882

A more detailed discussion of these factors is presented within the business unit analysis.

For the year ended December 31, 2010, APUC experienced an average U.S. exchange rate of approximately $1.030 as compared to $1.142 in the same period in 2009. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the year ended December 31, 2010 totalled $75.1 million as compared to $79.4 million during the same period in 2009, a decrease of $4.3 million or 5.4%. The decrease in Adjusted EBITDA is in part due to lower earnings from operations primarily resulting from lower average hydrology and wind resources in the Renewable Energy division and the impact of the outage at the Energy-From-Waste ("EFW") facility, partially offset by the acquisition of 36.8 MW of electrical generating assets located in New Brunswick and Maine (the "Tinker Assets") and the completion of various rate case proceedings in Liberty Water as compared to the same period in 2009. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2010, net earnings totalled $19.6 million as compared to $31.3 million during the same period in 2009, a decrease of $11.6 million or 37.2%. Net earnings per share totalled $0.21 for the year ended December 31, 2010, as compared to net earnings per trust unit of $0.39 during the same period in 2009.

Net earnings for the year ended December 31, 2010 decreased by $4.2 million due to increased interest expense, $1.4 million in reduced interest dividend and other income primarily due to gains on the sale of excess land earned in 2009, $0.8 million due to lower earnings from operating facilities, $0.7 million due to lower non-cash gains on U.S. denominated liabilities resulting from the stronger Canadian dollar and $3.3 million due to increased management and administration expense as compared to the same period in 2009. These items were partially offset by an increase of $4.0 million related to lower write downs of property plant and equipment and note receivables, $1.8 million related to increased recoveries of future income tax expense primarily due to the reasons discussed in *Annual Corporate and Other Expenses – Income Taxes,* $2.3 million resulting from reduced minority interest expense at the St. Leon facility primarily due to the lower wind resource experienced in the year ended December 31, 2010 as compared to the same period in 2009. In the comparable period, APUC incurred expenses of $4.7 million related to management internalization and $3.5 million related to corporatization expenses which were not incurred in the current period.

The decrease in net earnings was impacted by a change in unrealized mark-to-market gains on derivative financial instruments which reduced earnings by $16.0 million in the year ended December 31, 2010 as compared to 2009, as a result of changes in the forward interest rate curve and the stronger Canadian dollar, in addition to an expense increase of $2.5 million related to realized losses on derivative financial instruments contracts settled in the period. A more detailed analysis of realized and unrealized mark-to-market gains and losses on foreign exchange contracts and interest swap contracts can be found later in this report under *Treasury Risk Management - Foreign currency risk*.

During the year ended December 31, 2010, cash provided by operating activities totalled $45.2 million or $0.48 per share as compared to cash provided by operating activities of $48.0 million, or $0.60 per share during the same period in 2009. Cash provided by operating activities exceeded dividends declared by 2.0 times during the year ended December 31, 2010 as compared to 2.5 times dividends/distributions declared during the same period in 2009. The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2010 is primarily due to increased realized losses from derivative instruments, increased interest expense and decreased cash flow from operating facilities as compared to the same period in 2009.

2010 Fourth quarter results from operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31 2010	2009
Revenue	**$ 48,874**	$ 43,441
Adjusted EBITDA [2]	**$ 20,693**	$ 18,027
Cash provided by Operating Activities	**18,299**	11,894
Net earnings	**16,888**	(1,366)
Adjusted net earnings[3]	**18,034**	11,504
Dividend/distributions to Shareholders/Unitholders [1]	**5,725**	4,998
Per share/trust unit		
Net earnings	**$ 0.18**	$ (0.03)
Adjusted net earnings[3]	**$ 0.19**	$ 0.14
Diluted net earnings	**$ 0.18**	$ (0.03)
Cash provided by Operating Activities	**$ 0.19**	$ 0.15
Dividends/distributions to Shareholders/Unitholders	**$ 0.06**	$ 0.06
Total Assets	**980,917**	1,013,413
Long Term Debt[4]	**257,429**	241,421

[1] Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into APCo trust units.
[2] APUC uses Adjusted EBITDA to enhance assessment and understanding of the operating performance of APUC without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted EBITDA is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[3] APUC uses Adjusted net earnings to enhance assessment and understanding of the performance of APUC without the effects of gains or losses on derivative financial instruments which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted net earnings is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[4] Includes the Airsource Senior Debt Financing which matures on October 31, 2011 and has been recorded as a current liability on the consolidated balance sheet.

For the three months ended December 31, 2010, APUC reported total revenue of $48.9 million as compared to $43.4 million during the same period in 2009, an increase of $5.4 million or 12.5%. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2010 as compared to the corresponding period in 2009 are set out as follows:

	Three months ended December 31, 2010
Comparative Prior Period Revenue	$ 43,441
Significant Changes:	
Acquisition of Tinker Hydro in Q1 2010	4,200
Liberty Water revenue increases primarily due to rate case approvals	1,400
Impact of shutdown at Energy-from-Waste facility	600
Effect of wind resource compared to prior year	600
Red Lily I – development, construction and supervision fees	600
Effect of hydrology compared to prior year	500
Change in operating model at Windsor Locks	(800)
Impact of the stronger Canadian dollar	(900)
Other	(767)
Current Period Revenue	$ 48,874

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended December 31, 2010, APUC experienced an average U.S. exchange rate of approximately $1.032 as compared to $1.057 in the same period in 2009. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended December 31, 2010 totalled $20.7 million as compared to $18.0 million during the same period in 2009, an increase of $2.7 million or 14.8%. The increase in Adjusted EBITDA is in part due to increased earnings from operations primarily resulting from the acquisition of the Tinker Assets and increased revenues from Liberty Water resulting from the completion of rate cases, partially offset by lower average hydrology in the Renewable Energy division and the impact of the stronger Canadian dollar as compared to the same period in 2009. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2010, net earnings totalled $16.9 million as compared to net loss of $1.4 million during the same period in 2009, an increase of $18.3 million. Net earnings per share totalled $0.18 for the three months ended December 31, 2010, as compared to net loss per share of $0.03 during the same period in 2009.

Net earnings for the three months ended December 31, 2010 increased by $5.4 million due to increased earnings from operating facilities, $4.9 million related to increased recoveries of income tax expense primarily due to the reasons discussed in *Annual Corporate and Other Expenses – Income Taxes*, and $4.0 million related to lower write downs of property plant and equipment and note receivables, as compared to the same period in 2009. These items were partially offset by increased expenses of $2.4 million due to increased management and administration expense, $1.1 million due to increased interest expense, $0.6 million due to increased amortization expense and $0.2 million due to lower non-cash gains on U.S. denominated liabilities resulting from the stronger Canadian dollar as compared to the same period in 2009. In the comparable period, APUC incurred expenses of $4.7 million related to management internalization, $3.5 related to corporatization expenses which were not incurred in the current period.

The change in unrealized mark-to-market losses/(gains) on derivative financial instruments resulting from changes in foreign exchange rates relate to contract periods which extend to fiscal 2013. Unrealized mark-to-market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. A more detailed analysis of realized and unrealized mark to market gains and losses on foreign exchange contracts and interest swap contracts can be found later in this report under *Treasury Risk Management - Foreign currency risk*.

During the three months ended December 31, 2010, cash provided by operating activities totalled $18.3 million or $0.19 per share as compared to cash provided by operating activities of $11.9 million, or $0.15 per trust unit during the same period in 2009. Cash provided by operating activities exceeded dividends declared by 3.2 times during the quarter ended December 31, 2010 as compared to 2.4 times distributions during the same period in 2009. The change in cash provided by operating activities after changes in working capital in the three months ended December 31, 2010, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2009.

Outlook

APCo

The APCo Renewable Energy division is expected to perform at long-term average resource conditions for hydrology and below average wind resources in the first quarter of 2011.

APCo's load supply and energy procurement contracts in northern Maine and the Independent System Operator New England ("ISO-NE") market (the "Energy Services Business") anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 30,000 MW-hrs of energy to its customers in the first quarter of 2011 and, based on long term average hydrology for this period, the Tinker Assets are anticipated to provide 40% of the energy required to service this load. Subsequent to December 31, 2010, the Energy Services Business entered into a three year contract with Maine Public Service Company, a regulated electric transmission and distribution utility serving approximately 36,000 electricity customer accounts in Northern Maine ("MPS") starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with the standard offer service is approximately 135,000 MW-hrs.

The capital upgrade at the EFW facility, completed in July 2010, is expected to result in higher throughput and lower operating costs at the facility in the first quarter of 2011 as compared to the same period in 2010 when the facility was temporarily shut down as a result of an unplanned outage experienced in January 2010. APCo Thermal Energy division's Sanger facility should meet APCo's expectations for the first quarter of 2011 and be in line with 2010 results. Hydro-mulch sales are expected to be similar to 2010 sales due to continuing low demand for hydro-mulch in the U.S.

APCo Thermal Energy division's Windsor Locks facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO-NE day-ahead market or to retail customers through the Energy Services Business. The facility did not commit any portion of its electrical capacity to the forward reserve market ("FRM") for the winter of 2011 due to unacceptably low auction prices. It is anticipated that performance during the first quarter of 2011 will be strong, resulting from moderate natural gas prices and a cold winter in the north-east U.S. that has resulted in high electricity prices. APCo has completed preliminary engineering for a repowering project at the Windsor Locks facility and is in negotiations with Ahlstrom regarding this project. For a more detailed description of the options and expected impact see *Development Division - Windsor Locks*.

Liberty Water

Liberty Water is forecasting modest customer growth in 2011 with the continuing economic recovery in the United States. Liberty Water provides water distribution and wastewater collection and treatment services, primarily in the southern and southwestern U.S. where communities have traditionally experienced long term growth and that provide continuing future opportunities for organic growth.

On December 11, 2010, the Arizona Corporate Commission ("ACC") approved an order authorizing a rate increase of U.S. $0.9 million for Rio Rico Utilities Inc., effective February 1, 2011. It is anticipated that the regulatory review of the proposed rates and tariffs for the Bella Vista, Northern Sunrise, and Southern Sunrise facilities will be completed in Q1 2011. Total revenue increases from rate cases completed in Arizona and Texas represent an additional U.S. $10.2 million in annualized revenue. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year.

Liberty Energy

In 2009, APUC announced plans to acquire the California Utility assets in partnership with Emera. The acquisition was approved by both the California Public Utilities Commission ("CPUC") and the Public Utilities Commission of Nevada in the fourth quarter of 2010. Subsequent to these approvals, the transaction was completed on January 1, 2011 for a purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. The acquisition was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility. Liberty Energy's ownership share of the cost of acquisition of the California Utility was primarily funded through the proceeds of subscription receipts held by Emera for 8.532 million APUC common shares at a price of $3.25 per share.

On December 9, 2010, Liberty Energy entered into agreements to acquire all issued and outstanding shares of Granite State and EnergyNorth from National Grid for total consideration of U.S. $285.0 million.

Liberty Energy is pursuing additional investments in electric distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best in-class-customer care for its subsidiary utility ratepayers.

APCo: Renewable Energy

	Three months ended December 31			Twelve months ended December 31		
	Long Term Average Resource	2010	2009	Long Term Average Resource	2010	2009
Performance (MW-hrs sold)						
Quebec Region	**72,575**	**84,125**	73,650	**276,825**	**275,850**	299,900
Ontario Region	**34,750**	**20,200**	30,350	**144,725**	**90,225**	134,800
Manitoba Region	**105,000**	**97,150**	89,625	**372,000**	**343,100**	364,500
New England Region	**15,425**	**13,380**	16,200	**65,275**	**47,900**	81,725
New York Region	**24,100**	**24,375**	24,750	**91,100**	**79,550**	95,000
Western Region	**13,400**	**10,450**	10,875	**67,250**	**59,100**	58,200
Maritime Region	**39,575**	**55,525**	2,425	**148,250**	**148,550**	7,025
Total	**304,825**	**305,205**	247,875	**1,165,425**	**1,044,275**	1,041,150
Revenue						
Energy sales		**$ 21,867**	$ 16,604		**$ 80,117**	$ 68,227
Less:						
Cost of Sales – Energy*		**(431)**	-		**(5,047)**	-
Net Energy Sales		**$ 21,436**	$ 16,604		**$ 75,070**	$ 68,227
Other Revenue		**563**	-		**2,122**	-
Total Net Revenue		**$ 21,999**	**$ 16,604**		**$ 77,192**	**$ 68,227**
Expenses						
Operating expenses		**(7,013)**	(6,619)		**(24,434)**	(22,279)
Interest and Other income		**151**	433		**783**	1,226
Division operating profit (including other income)		**$ 15,137**	$ 10,418		**$ 53,541**	$ 47,174

* Cost of Sales – Energy consists of energy purchases by the Energy Services Business, where this energy is sold to customers pursuant to fixed rate energy contracts.

As APCo's hydroelectric generating facilities in the New York and New England regions primarily sell their output at market rates, the average revenue earned per MW-hr sold can vary significantly from the same period in the prior period or year. APCo's hydroelectric generating facilities in the Maritime region primarily sell their output to the Energy Services Business which, in turn, sells this energy at fixed price contracts to local electric utilities and commercial buyers in Northern Maine. APCo's facilities in the other regions are subject to varying rates, by facility, as set out in each facility's individual PPA. As such, while most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

2010 Annual Operating Results

For the twelve months ended December 31, 2010 the Renewable Energy division produced 1,044,275 MW-hrs of electricity, as compared to 1,041,150 MW-hrs produced in the same period in 2009, an increase of 0.3%. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 58,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 575,000 tons of CO2 gas was prevented from entering the atmosphere in 2010.

For the year ended December 31, 2010, the division generated electricity equal to 90% of long-term projected average resources (wind and hydrology) as compared to 102% during the same period in 2009. Over 2010, the Maritime and Quebec regions experienced resources generally consistent with long-term averages. The Manitoba, New York and Western regions experienced resources within 15% of long-term averages. The Ontario region experienced resources approximately 40% below long-term averages and the New England region experienced resources approximately 25% below long-term averages. The lower wind resource in the Manitoba region in the first quarter and fourth quarters of 2010 was similar to lower wind resources experienced at other wind farms in North America.

For the year ended December 31, 2010, revenue from energy sales in the Renewable Energy division totalled $80.1 million, as compared to $68.2 million during the same period in 2009, an increase of $11.9 million or 17.4%. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the year ended December 31, 2010, net revenue from energy sales in the Renewable Energy division totalled $75.1 million, as compared to $68.2 million during the same period in 2009, an increase of $6.8 million or 10.0%.

Revenue from APCo's New England and New York region facilities increased $0.8 million due to an increase in weighted average energy rates of approximately 15.8% and decreased $2.4 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba region increased $1.0 million due to an increase in weighted average energy rates of approximately 5.9%, offset by a decrease of $1.2 million due to a weaker wind resource, as compared to the same period in 2009. The power purchase agreement associated with the St. Leon facility requires the facility to generate a minimum amount of dependable energy during the annual contract year ending April 30. Energy generated above the dependable amount earns revenue at lower, non-dependable rates. As a result of the lower production experienced in the first quarter of 2010, during the annual contract year ending April 30, 2010, the facility earned revenue primarily at the dependable rates as compared to the same period in 2009 when a greater proportion of revenue was earned at the non-dependable rates. Revenue generated by the Ontario, Quebec and Western regions increased by $1.9 million due to an increase in weighted average energy rates of approximately 6.3%, primarily the result of increased rates at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The increases in revenue at APCo's Ontario, Quebec and Western regions were offset by a decrease of $4.8 million due to lower energy production, primarily the result of lower production from reduced hydrologic resources available at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The Maritime region, in conjunction with the Energy Services Business, generated $17.7 million in revenue, before energy purchases. This revenue arose from electricity sales under sales agreements with local electric utilities and wholesale consumers in Northern Maine ($14.0 million) and New Brunswick ($1.9 million) and merchant sales of production in excess of customer demand ($1.7 million).

Other revenue for the year ended December 31, 2010 totalled $2.1 million, as compared to nil during the same period in 2009. Other revenue represents amounts earned related to the development and construction of the Red Lily I wind project.

The division reported decreased revenue of $0.6 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the year ended December 31, 2010, energy purchase costs of the Energy Services Business totalled U.S. $4.9 million. In 2010, the Energy Services Business purchased approximately 74,900 MW-hrs of energy at market and fixed rates averaging U.S. $65 per MW-hr. The Maritime region generated approximately 65% of the load required to service its customers as well as the Energy Services Business' customers in 2010. The energy purchases represent a combination of the load requirement of the Energy Services Business' customers and the timing of this demand as compared to the energy produced by the Tinker Assets and the timing of this production. The division reported increased energy costs of $0.1 million as a result of the Canadian dollar exchange rates.

For the year ended December 31, 2010, operating expenses excluding energy purchases totalled $24.4 million, as compared to $22.3 million during the same period in 2009, an increase of $2.2 million or 9.7%. Operating expenses were impacted by $1.5 million of increased expenses at the St. Leon facility, primarily resulting from scheduled payments under the extended warranty and operation and maintenance agreement with Vestas, $0.6 million of increased operating expenses at the U.S. hydroelectric facilities, and $2.9 million related to operating costs associated with the Tinker Assets and the Energy Services Business as compared to the same period in 2009. These increases were partially offset by $0.6 million in decreased operating costs at Canadian facilities, primarily due to lower variable operating costs tied to lower revenue and lower repair and maintenance projects commenced in 2010. Operating expenses include costs incurred in the period of $1.1 million associated with the pursuit of various growth and development activities, including operating expenses associated with the construction supervision work on the Red Lily I wind project, as compared to development costs incurred of $2.1 million in the same period in 2009. Operating expenses in 2010 were lower due to a reimbursement of $0.9 million related to costs previously expensed by APUC in connection with the development of the Red Lily I wind project. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the year ended December 31, 2010, Renewable Energy's operating profit totalled $53.5 million, as compared to $47.2 million during the same period of 2009, representing an increase of $6.4 million or 13.5%. Renewable Energy's operating profit did not meet APCo's expectations primarily due to a lower than expected wind resource in the Manitoba region in the first quarter of 2010 and lower hydrology in the second and third quarters of 2010.

2010 Fourth Quarter Operating Results

For the quarter ended December 31, 2010, the Renewable Energy division produced 305,205 MW-hrs of electricity, as compared to 247,875 MW-hrs produced in the same period in 2009, an increase of 23.1%. The increased generation is primarily due to the acquisition of the Tinker Hydro facility in January 2010 and therefore did not form part of the production in the comparable period in 2009. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 68,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 168,000 tons of CO2 gas was prevented from entering the atmosphere in the fourth quarter of 2010.

During the quarter ended December 31, 2010, the division generated electricity equal to long-term projected average resources (wind and hydrology) as compared to 93% during the same period in 2009. In the fourth quarter of 2010, the Maritimes and Quebec regions experienced resources significantly higher than long-term averages, producing approximately 40% and 15% above long-term average resources, respectively. The New York region experienced resources approximately equal to the long-term average, while the Manitoba and New England regions experienced resources of approximately 10% below long-term averages. The Ontario and Western regions experienced results significantly below long-term average resources.

For the quarter ended December 31, 2010, revenue from energy sales in the Renewable Energy division totalled $21.9 million, as compared to $16.6 million during the same period in 2009, an increase of $5.3 million or 31.7%. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2010, net revenue from energy sales in the Renewable Energy division totalled $21.4 million, as compared to $16.6 million during the same period in 2009, an increase of $4.8 million or 29.1%.

Revenue from APCo's New England and New York region facilities increased $0.2 million due to an increase in weighted average energy rates of approximately 15.5%, offset by $0.3 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba region increased $0.6 million primarily due to a stronger wind resource, as compared to the same period in 2009. Revenue generated by the Ontario, Quebec and Western regions increased by $0.2 million due to an increase in weighted average energy rates of approximately 2.0%, primarily the result of increased rates at the Long Sault facility in the Ontario region, and $0.2 million due to increased energy production, primarily the result of increased production in the Quebec region, as compared to the same period in 2009. The Maritime region, in conjunction with the Energy Services Business, generated $4.2 million in revenue, before energy purchases. This revenue consists of sales to local electric utilities and wholesale consumers in Northern Maine ($2.6 million) and New Brunswick ($0.6 million) and merchant sales of production in excess of customer demand and other revenue ($0.9 million).

Other revenue for the three months ended December 31, 2010 totalled $0.6 million, as compared to nil during the same period in 2009. Other revenue represents amounts earned related to the development and construction of the Red Lily I wind project.

For the quarter ended December 31, 2010, energy purchase costs by the Energy Services Business totalled U.S. $0.4 million. During the quarter, the Energy Services Business purchased approximately 9,500 MW-hrs of energy at market and fixed rates averaging $44 per MW-hr. The Maritime region generated approximately 95% of the load required to service its customers as well as the Energy Services Business' customers in the three months ended December 31, 2010. The energy purchases represent a combination of the load requirement of the Energy Services Business' customers and the timing of this demand as compared to the energy produced by the Tinker Assets and the timing of this production.

For the quarter ended December 31, 2010, operating expenses excluding energy purchases totalled $7.0 million, as compared to $6.6 million during the same period in 2009, an increase of $0.4 million or 6.0%. Operating expenses were impacted by $0.2 million of increased expenses at the St. Leon facility, primarily resulting from scheduled payments under the extended warranty and operation and maintenance agreement with Vestas and $1.0 million related to operating costs associated with the Tinker Assets and the Energy Services Business, as compared to the same period in 2009. These increases were partially offset by $0.4 million in decreased operating costs at Canadian facilities primarily due to lower variable operating costs. Operating expenses include costs incurred in the period of $0.8 million associated with the pursuit of various growth and development activities, including operating expenses associated with the construction supervision work on the Red Lily I wind project as compared to development costs incurred of $0.9 million in the same period in 2009. The division reported decreased expenses of $0.2 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended December 31, 2010, Renewable Energy's operating profit totalled $15.1 million, as compared to $10.4 million during the same period of 2009, representing an increase of $4.7 million or 45.3%. For the quarter ended December 31, 2010, Renewable Energy's operating profit met APCo's expectations primarily due to improved hydrology in the quarter in the Quebec and Maritime regions.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform at long-term average resource conditions for hydrology and below long-term average wind resources in the first quarter of 2011.

The construction phase of the Red Lily I project is now complete with commercial operation occurring under the SaskPower PPA in February 2011. The power purchase agreement with SaskPower is for 25 years and includes a 2% annual increase throughout the term of the agreement. APUC's investment of $19.6 million in the Red Lily I facility has been initially structured as senior and subordinated debt bearing a blended interest rate of 8.43%. The balance of the total expected project construction costs of $71.2 million have been financed by senior debt from third party lenders in the amount of $31.0 million and an equity contribution from an independent investor estimated to be $20.6 million. In addition to interest payments on its debt financing, APUC is entitled to certain supervisory fees, estimated at $1.3 million in the first full year of operation. Total interest and fee payments in 2011 are estimated to be approximately $2.4 million representing approximately 75% of net cash flows from the facility. APUC has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest, exercisable in February 2016.

The Energy Services Business anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 30,000 MW-hrs of energy to its customers in the first quarter of 2011. Based on historical long term average levels of hydroelectric energy generation for the first quarter of 2011, the Tinker Assets are anticipated to provide 40% of the energy required by the Energy Services Business to service its customers which provides a natural hedge on supply costs of the Energy Services Business. In respect of each customer delivery obligation, the Energy Services Business has in place fixed price financial energy contracts to operationally hedge the price of the customer supply obligation and to minimize the volatility of the energy price. These contracts in combination with the expected Tinker production are used to balance the monthly customer load.

Subsequent to December 31, 2010, the Energy Services Business entered into a three year contract with MPS starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with this bid is approximately 135,000 MW-hrs.

As a result of certain legislation passed in Quebec (Bill C93), APCo's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. As a result of the assessments and a preliminary evaluation of the associated remedial work, APCo currently estimates capital expenditures of approximately $17.1 million related to compliance with the legislation. The timing of when the actual capital costs need to be made is determined as part of the technical assessments.

APCo anticipates that these expenditures will be invested over a period of several years approximately as follows:

	Total	2011	2012	2013	2014	2015
Estimated Bill C-93 Capital Expenditures	**17,100**	800	5,000	5,500	3,000	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities. APCo does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. APCo continues to explore several alternatives to mitigate the capital costs of the modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

APCo: Thermal Energy Division

	Three months ended December 31		Twelve months ended December 31	
	2010	2009	2010	2009
Performance (MW-hrs sold)	**120,600**	147,482	**465,390**	571,505
Performance (tonnes of waste processed)	**43,535**	42,189	**90,690**	161,102
Revenue				
Energy sales	**$ 12,185**	$ 13,819	**$ 52,609**	$ 62,209
Less:				
Cost of Sales – Fuel *	**(5,492)**	(5,224)	**(22,348)**	(26,517)
Net Energy Sales Revenue	**$ 6,693**	$ 8,595	**$ 30,261**	$ 35,692
Waste disposal sales	**4,164**	3,786	**9,039**	14,468
Other revenue	**311**	545	**1,209**	3,848
Total net revenue	**$ 11,168**	$ 12,926	**$ 40,509**	$ 54,008
Expenses				
Operating expenses *	**(6,127)**	(7,121)	**(23,948)**	(30,782)
Interest and other income	**100**	140	**495**	821
Division operating profit (including interest and dividend income)	**$ 5,141**	$ 5,945	**$ 17,056**	$ 24,047

* Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities.

APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and in different regional hubs. As a result, the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other showing decreasing costs, as compared to the same period in the prior year. *'Cost of Sales – Fuel'* is calculated as the volume of natural gas consumed by a facility times the average landed cost of natural gas. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed cost for natural gas combined with a consumption of a higher volume of natural gas.

2010 Annual Operating Results

In 2010, the EFW facility processed 90,690 tonnes of municipal solid waste as compared to 161,102 tonnes processed in the same period of 2009, a decrease of 43.7%. The significantly reduced throughput was a result of the unplanned outage experienced in January 2010 which resulted in the facility being temporarily shut down. The major capital upgrades to the facility were completed at the end of the second quarter and the facility was restarted on July 14, 2010. The status of this facility is discussed in further detail in *Divisional Outlook – Thermal Energy*, below. This level of production resulted in the diversion of approximately 65,000 tonnes of waste from landfill sites in 2010.

For the year ended December 31, 2010, the Thermal Energy Division produced 465,390 MW-hrs of energy as compared to 571,505 MW-hrs of energy in the comparable period of 2009. During the year ended December 31, 2010, the business unit's performance decreased by 83,800 MW-hrs at the Windsor Locks facility, 23,000 MW-hrs at the land-fill gas ("LFG") facilities and 3,500 MW-hrs from EFW's steam turbine, partially offset by an increase of 3,900 MW-hrs at the Sanger facility, as compared to the same period in 2009.

The decrease in electrical generation at the Windsor Locks facility was the expected result of the expiry of the PPA with Connecticut Light & Power in April 2010 and the change in operating model for the facility to one where revenues are earned from payments under the continuing energy sales agreement with the co-located electricity and thermal energy host augmented by capacity and energy payments from the ISO-NE and associated markets. As a result, the facility will only generate additional energy beyond that needed to service the existing industrial customer when market conditions warrant, resulting in reduced energy production compared to the historic operating model. The decrease in electrical generation at the EFW facility was the result of the unplanned outage which occurred in January 2010.

For the year ended December 31, 2010, APCo ceased generating energy at the LFG facilities, initiated a process to close these facilities and sold the generating assets. See *APUC Annual Corporate and other Expenses* for additional details related to the write down in the carrying value of these assets.

For the year ended December 31, 2010, revenue in the Thermal Energy division totalled $62.9 million, as compared to $80.5 million during the same period in 2009, a decrease of $17.7 million or 21.9%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. During the year ended December 31, 2010, net energy sales revenue at the Thermal Energy division totalled $30.3 million, as compared to $35.7 million during the same period in 2009, a decrease of $5.4 million or 15.2%.

For the year ended December 31, 2010, energy sales revenue in the Thermal Energy division totalled $52.6 million, as compared to $62.2 million during the same period in 2009, a decrease of $9.6 million or 15.4%. The decrease in revenue from energy sales was primarily due to a decrease of $6.7 million at the Windsor Locks facility as a result of decreased production, partially offset by an increase of $3.0 million as a result of increased energy rates, in part due to a higher average landed price per mmbtu for natural gas and the change in operating model of the facility and a decrease of $1.3 million as a result of the closure of the LFG facilities, as compared to the same period in 2009. The decreases were partially offset by an increase in revenue from energy sales $0.4 million at the Sanger facility as a result of increased energy rates, in part due to higher average landed price per mmbtu for natural gas and $0.5 million at the Sanger facility as a result of increased production, as compared to the same period in 2009. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $5.4 million from operations as a result of the stronger Canadian dollar, as compared to the same period in 2009.

Revenue from waste disposal sales in 2010 totalled $9.0 million, as compared to $14.5 million during the same period in 2009, a decrease of $5.4 million or 37.6%. The EFW facility generated lower revenue in the period as it was temporarily shut down between January and July 2010 as a result of the unplanned outage.

Other revenue for the year ended December 31, 2010 totalled $1.2 million, as compared to $3.8 million during the same period in 2009, a decrease of $2.6 million or 68.6%. The decrease in other revenue was primarily due to a decrease of $1.6 million at the hydro-mulch facility due to reduced customer demand. In the comparable period in 2009, other revenue included $0.6 million from APCo's LFG facilities which were not operational in the current period. The division reported decreased other revenue of $0.5 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the year ended December 31, 2010, fuel costs at Sanger and Windsor Locks totalled U.S. $21.7 million, as compared to U.S. $23.0 million during the same period in 2009, a decrease of U.S. $1.3 million. The overall natural gas expense at the Windsor Locks facility decreased $1.8 million (10%), primarily the result of a 14% reduction in volume of natural gas consumed, partially offset by a 5% increase in the average landed cost of natural gas per mmbtu, as compared to the same period in 2009. The average landed cost of natural gas at the Windsor Locks facility was U.S. $4.84 per mmbtu. The reduction in natural gas expense was partially offset by an increase in the overall natural gas expense at Sanger of $0.5 million (12%), primarily the result of an 11% increase in the average landed cost of natural gas per mmbtu. The average landed cost of natural gas at the Sanger facility was U.S. $4.79 per mmbtu. The division reported decreased fuel costs of $2.9 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the year ended December 31, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $23.9 million, as compared to $30.8 million during the same period in 2009, a decrease of $6.8 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of

$5.1 million at the EFW facility resulting from the outage at the facility, reduced material costs of $0.9 million at the hydro-mulch facility resulting from lower production, and $1.7 million of lower costs due to the closing of the LFG facilities partially offset by increased natural gas expense of $1.3 million at the Brampton Cogeneration Inc. ("BCI") facility as a result of decreased steam production at EFW and increased steam production from BCI's auxiliary boiler as compared to the same period in 2009. Operating expenses included costs of $0.5 million associated with the pursuit of various growth and development activities, as compared to nil in the same period in 2009. The division reported decreased operating expenses of $1.4 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

Interest and other income for the year ended December 31, 2010 totalled $0.5 million, as compared to $0.8 million in the same period in 2009. During the year ended December 31, 2010, APUC determined that earnings from equity investments should be presented at the corporate level rather than at a divisional level. As a result, the comparable figures have been reclassified to conform to the presentation adopted in the current year.

For the year ended December 31, 2010, the Thermal Energy division's operating profit totalled $17.1 million, as compared to $24.0 million during the same period in 2009, representing a decrease of $7.0 million or 29%. Operating profit in the Thermal Energy division did not meet overall expectations for the year ended December 31, 2010, primarily due to the unplanned outage at the EFW facility, the change in operating model at Windsor Locks and lower demand for hydro-mulch resulting from the current economic slow down in the U.S.

2010 Fourth Quarter Operating Results

During the quarter ended December 31, 2010, the EFW facility processed 43,535 tonnes of municipal solid waste as compared to 42,189 tonnes processed in the same period of 2009, an increase of 3.2%. This level of production resulted in the diversion of approximately 32,000 tonnes of waste from municipal solid waste landfill sites in 2010.

During the quarter ended December 31, 2010, the business unit produced 120,600 MW-hrs of energy as compared to 147,482 MW-hrs of energy in the comparable period of 2009. During the quarter ended December 31, 2010, the business unit's performance decreased by 25,300 MW-hrs at the Windsor Locks facility and 5,600 MW-hrs at the LFG facilities, partially offset by an increase of 3,000 MW-hrs at the Sanger facility and 1,000 MW-hrs at the EFW facility, as compared to the same period in 2009. See the discussion of the annual operating results regarding the decrease in electrical generation at the Windsor Locks facility.

During the quarter ended December 31, 2010, APCo sold the generating assets at the LFG facilities. See *APUC Annual Corporate and other Expenses* for additional details related to the write-down in the carrying value of these assets.

For the quarter ended December 31, 2010, revenue in the Thermal Energy division totalled $16.7 million, as compared to $18.2 million during the same period in 2009, a decrease of $1.5 million, or 8.2%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended December 31, 2010, net energy sales revenue at the Thermal Energy division totalled $6.7 million, as compared to $8.6 million during the same period in 2009, a decrease of $1.9 million.

For the quarter ended December 31, 2010, energy sales revenue in the Thermal Energy division totalled $12.2 million, as compared to $13.8 million during the same period in 2009, a decrease of $1.6 million or 11.8%. The decrease in revenue from energy sales was primarily due to a decrease of $1.8 million at the Windsor Locks facility as a result of decreased production, partially offset by an increase of $1.0 million as a result of increased energy rates, in part due to a higher average landed price per mmbtu for natural gas and the change in operating model of the facility and a decrease of $0.3 million as a result of the closure of the LFG facilities, as compared to the same period in 2009. The decrease in revenue was partially offset by $0.1 million at the BCI facility as a result of increased price for steam, as compared to the same period in 2009. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $0.4 million from operations as a result of the stronger Canadian dollar, as compared to the same period in 2009.

Revenue from waste disposal sales for the quarter ended December 31, 2010 totalled $4.2 million, as compared to $3.8 million during the same period in 2009. The increase was a result of the EFW facility processing a higher throughput of municipal solid waste as compared to the same period in 2009.

Other revenue for the quarter ended December 31, 2010 totalled $0.3 million, as compared to $0.5 million during the same period in 2009. The decrease in other revenue was due to decreased revenue at the hydro-mulch facility due to reduced customer demand in the quarter.

For the quarter ended December 31, 2010, fuel costs at Sanger and Windsor Locks totalled U.S $5.4 million, as compared with U.S $4.9 million in the same period in 2009, an increase of U.S. $0.5 million. The overall natural gas expense at the Windsor Locks facility increased $0.5 million (14%), primarily the result a 45% increase in the average landed cost of natural gas per mmbtu, partially offset by a 21% reduction in volume of natural gas consumed, as compared to the same period in 2009. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $5.00 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of $0.1 million (4%), primarily the result of a 10% decrease in the average landed cost of natural gas per mmbtu, partially offset by a 7% increase in the volume of natural gas consumed as compared to the same period in 2009. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.40 per mmbtu. The division reported decreased fuel costs of $0.2 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended December 31, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $6.1 million, as compared to $7.1 million during the same period in 2009, a decrease of $1.0 million. The decrease in operating expenses for the quarter was primarily due to reduced material costs of $0.2 million at the hydro-mulch facility resulting from lower production, $0.1 million of reduced operating costs at BCI and $0.8 million of reduced operating costs at the LFG facilities partially offset by $0.3 million in increased operating costs at the Windsor Locks facility as compared to the same period in 2009.

Interest and other income for the three months ended December 31, 2010 totalled $0.1 million, consistent with the same period in 2009.

For the quarter ended December 31, 2010, the Thermal Energy division's operating profit totalled $5.1 million, as compared to $5.9 million during the same period in 2009, representing a decrease of $0.8 million or 13.5%. Operating profit in the Thermal Energy division did not meet overall expectations for the quarter ended December 31, 2010, primarily due to lower than expected earnings at the Windsor Locks facility as a result of decreased production volume.

Divisional Outlook – Thermal Energy

The capital upgrade completed at the EFW facility is expected to result in higher throughput and lower operating costs at the facility which should positively affect operating profit generated by the facility in 2011 as compared to the same period in 2010 when the facility was temporarily shut down as a result of an unplanned outage experienced in January 2010. APCo Thermal Energy division's Sanger facility should meet APCo's expectations for the first quarter of 2011 and be in line with 2010 results. Hydro-mulch sales are expected to be similar to 2010 sales due to continuing low demand for hydro-mulch in the U.S.

APCo Thermal Energy division's Windsor Locks facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO-NE day-ahead market or to industrial customers through the Energy Services Business. The facility did not commit any portion of its remaining capacity to the FRM for the winter of 2011 due to unacceptably low auction prices. It is anticipated that performance during the first quarter of 2011 will be strong, resulting from moderate gas prices and a cold winter in the north-east U.S. that have resulted in high electricity prices.

Algonquin has completed preliminary engineering for a repowering project at the Windsor Locks facility and is in negotiations with the steam host regarding this project. See *APCo Development Division – Windsor Locks* for further discussion on the potential repowering project.

APCo: Development Division

The Development division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. The Development division is led by six full time employees who have access to, and support from, all of APCo's available resources to assist it in the development of projects. Typically, the division draws upon the support of the finance, engineering, technical services, and environmental and regulatory compliance groups. It also utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The Development division believes that the prevailing economic climate has also created opportunities for APCo to acquire third party development projects on terms that require the experience and financial resources that APCo has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

Industry Outlook

Environmental concerns, increases in electricity demand and fossil fuel price volatility have combined to create the impetus for governments, regulatory bodies and utilities to diversify their mix of power generation. This diversification has largely been focused on developing a larger proportion of renewable power and high-efficiency gas generation. Consequently, a favourable policy environment has emerged for independent producers and developers of renewable and thermal power generation, particularly in the areas of wind, hydroelectric and natural gas generation. Additionally, there has been a general recognition that energy produced by independent producers which is priced in the context of market competition offer a lower cost means of production to utilities.

An increasing amount of attention has been paid to the environmental value of both renewable and efficient means of power production and the ability of the power industry to offset the ill-effects of production by higher polluting fossil fuels. To the extent that a renewable or efficient source of energy can offset a fossil fuelled generating source, it can, in some cases, generate a carbon credit which can then be sold to a third party. Despite the fact that there is no nationally recognized carbon reduction program in either the U.S. or Canada, there remain several regional organizations that have been established with targets to reduce carbon emissions. Globally, the value of the carbon market doubled for three consecutive years from U.S. $31.2 billion in 2006 to U.S. $138.9 billion in 2009. This should enhance the ability to develop future renewable sources of generation.

Divisional Outlook - Development

It is anticipated that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the U.S., continue to increase targets for renewable and other clean power generation projects. In May 2009, the Ontario government passed the Green Energy Act ("GEA"). Accordingly the OPA has issued standard pricing for electricity from renewable sources under a FIT program. Included within this legislation is the requirement for OPA to purchase power generated from green energy projects, and an obligation for all utilities to grant priority grid access to such projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.

Other jurisdictions have passed similar legislation. British Columbia has announced the Clean Energy Act and Nova Scotia is pursuing the 2010 Renewable Electricity Plan and will be establishing pricing for its ensuing Community FIT program in April of 2011. Both of these proposed pieces of legislation have set aggressive targets for the development of new, renewable power production. They also introduce the concept of fixed pricing based on a FIT for some categories of new renewable power projects. The combination of increased renewable production targets and appropriate fixed pricing will present investment opportunities for APCo to consider in the future.

Current Development Projects

Amherst Island

On February 25, 2011, APUC announced that the OPA has awarded a FIT contract to the wholly-owned 75 MW Amherst Island Wind Project, located on Amherst Island in the village of Stella, approximately 25 kilometers southwest of Kingston, Ontario. The contract has been awarded as part of the second round of the OPA's FIT program.

The project, which will be developed by APCo, is currently contemplated to use more efficient Class III wind turbine generator technology. While final turbine selection remains to be made, modelling the higher energy capture ratios of turbines, such as the Vestas V100 or Repower MM100, forecast that the available wind resource would produce approximately 247 GW hrs of power annually. Funding for the total capital costs currently estimated to be $220 million will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 months.

Quebec Community Wind Projects

In July 2010, APCo worked with Société en Commandite Val-Eo, a cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded contracts that stipulate the use of ENERCON turbines.

The quantum of the interests of APUC in the Saint-Damase and Val- Éo projects is subject to final negotiations with the partners in the projects but, in any event, will not be less than 50% and 25%, respectively. Final funding of the projects will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting will begin for both projects in early 2011, with all major authorizations targeted for completion by the end of 2012.

St. Damase

The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APUC. The first 24 MW phase of the project is currently envisioned to consist of twelve 2MW ENERCON E-82 wind turbine generators, producing approximately 86,000 MW-hrs annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

Val Eo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APUC. The first 24 MW phase of the project is expected to be comprised of eight 3MW ENERCON E-101 wind turbine generators, producing approximately 66,000 MW-hrs annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

Red Lily II

In addition to the now completed Red Lily I project, APCo has secured additional land options related to property around Red Lily I to facilitate a 106 MW expansion ("Red Lily II"). The viability of the expanded project will be conditional upon a review of the actual operating results from Red Lily I. During the first quarter of 2010, APCo responded to the request for quotations issued by SaskPower by submitting requested information pertaining to Red Lily II.

Successful development of wind projects is subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs and construction risk that the project is built without mechanical defects and is completed on time and within budget estimates.

Windsor Locks

The Windsor Locks facility is a 54 MW natural gas power generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom Windsor Locks, LLC (“Ahlstrom”), a leading paper and non-woven materials manufacturer, pursuant to an energy services agreement (“ESA”) which expires in 2017.

The balance of Windsor Locks’ electrical generating capacity is sold to customers through the ISO-NE electrical market. The facility currently participates in the ISO-NE Forward Capacity Market and the day-ahead energy market. Assuming acceptable auction pricing is available in April 2011, the additional electrical capacity of approximately 26 MW at the Windsor Locks facility will be made available into the summer 2011 Forward Reserve Market. In addition, APCo’s Energy Services Business will use the production from the Windsor Locks facility to support retail industrial electrical sales in the ISO-NE market.

APCo has completed preliminary engineering and environmental permitting work for the installation of a 14.2 MW combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of Ahlstrom. The total expected capital cost for this project is estimated at approximately U.S. $20 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million to offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to Windsor Locks of approximately $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO-NE market. APCo also believes that this project would qualify for a combined heat and power Investment Tax Credit (“ITC”) grant program sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant. APCo’s decision to make any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

During 2011, it is expected that APCo will continue to earn revenue from steam and electrical sales to Ahlstrom, steam and electrical capacity payments made by Ahlstrom, as well as energy and capacity payments through sales to ISO-NE. Under the expected NE-ISO operating protocol APCo will need to acquire approximately 0.9 million MMBTU of natural gas annually in addition to the amount of natural gas purchased to serve the needs of Ahlstrom (in respect of which APCo receives reimbursement from Ahlstrom under the ESA).

Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the U.S.

In addition to Red Lily II, APCo is currently collecting wind data on three sites in Saskatchewan and responded to Saskatchewan’s Request for Qualifications to procure up to 175 MW of wind power from one or more independent power producers. These sites have met the qualifications and APCo will likely submit project proposals into future RFPs.

Discussions with the OPA indicate that energy procurement initiatives have been positively influenced by the GEA. The GEA is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by APCo as positive for the development of renewable energy in Ontario. The Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the OPA in accordance with the GEA.

APCo had previously submitted applications for approximately 120 MW of on-shore wind energy projects in eastern Ontario under the GEA’s FIT program. The on-shore wind price set by the FIT program is $0.135 per KWh. In February 2011, APCo received notification that a power purchase agreement was awarded for its 75 MW Amherst Island wind project, approximately 25km from Kingston, Ontario. APCo has received confirmation from the OPA that the remaining 45 MW of applications submitted under the FIT program are now being reviewed under the Economic Connection Test.

APCo has applied to become applicant of record for three Crown land sites in Ontario under the Ministry of Natural Resources wind power site release program.

Each project being contemplated is subject to a significant level of due diligence and financial modeling to ensure it satisfies return and diversification objectives established for the Development division. Accordingly, the likelihood of proceeding with some or all of these projects depends on the outcome of due diligence, material contract negotiations, the structure of future calls for tender, and request for proposal programs. To maximize APCo's opportunities for development, new renewable and high efficiency thermal energy generating facilities are being pursued utilizing a variety of technologies and in diverse geographic locations.

Future Development Projects – Existing Facilities

APCo is exploring multiple options related to the St. Leon facility including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 85 MW. In the event these projects are developed, it is currently estimated to require an investment of approximately $250 million.

Future Development Projects – Other

APCo has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. APCo believes this project is an excellent fit for the Minister of Energy and Infrastructure's (the "Ministry") Directive to procure electricity from combined heat and power projects. The Ministry is currently taking registrations from interested parties that wish to participate in such a program.

LIBERTY WATER

	Twelve months ended December 31		Twelve months ended December 31	
	2010	**2009**	**2010**	**2009**
Number of				
Wastewater connections			**35,420**	34,679
Wastewater treated (millions of gallons)			**2,000**	1,925
Water distribution connections			**37,666**	36,919
Water sold (millions of gallons)			**5,500**	5,900
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,258**	147,581		
Revenue				
Wastewater treatment	**$ 19,979**	$ 17,983	**$ 20,704**	$ 20,601
Water distribution	**15,877**	14,996	**16,453**	17,179
Other Revenue	**603**	640	**629**	733
	$ 36,459	$ 33,619	**$ 37,786**	$ 38,513
Expenses				
Operating expenses	**(21,250)**	(20,055)	**(22,074)**	(23,158)
Other income	**82**	1,220	**85**	1,368
Business Unit operating profit (including other income)	**$ 15,291**	$ 14,784	**$ 15,797**	$ 16,723

Liberty Water is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Water has presented the division's results in both the reporting currency and its functional currency. Liberty Water believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Water's functional currency without the impact of foreign exchange.

Liberty Water reports total connections, inclusive of vacant connections rather than customers. Liberty Water had 35,420 wastewater connections as at December 31, 2010, as compared to 34,679 as at December 31, 2009, an increase of 741 in the period or 2.1%. Liberty Water had 37,666 water distribution connections as at December 31, 2010, as compared to 36,919 as at December 31, 2009, representing an increase of 747 in the period or 2.0%. Total connections include approximately 1,900 vacant wastewater connections and 1,400 vacant water distributions connections as at December 31, 2010. Bad debt expense in 2010 decreased by approximately $0.1 million compared to 2009. Liberty Water's change in water distribution and wastewater treatment customer base during the period is primarily due to the acquisition of a small utility in Texas during the first quarter of 2010 and modest growth at Liberty Water's other facilities.

Liberty Water has investments in regulatory assets of U.S. $155.3 million across four states as at December 31, 2010, as compared to U.S. $147.6 million as at December 31, 2009 and has substantially completed proceedings in Texas and Arizona to allow it to earn its full regulatory return on its investment in regulatory assets.

2010 Annual Operating Results

During the year ended December 31, 2010, Liberty Water provided approximately 5.5 billion U.S. gallons of water to its customers, treated approximately 2.0 billion U.S. gallons of wastewater and sold approximately 345 million U.S. gallons of treated effluent.

For the year ended December 31, 2010, Liberty Water's revenue totalled U.S. $36.5 million as compared to U.S. $33.6 million during the same period in 2009, an increase of U.S. $2.8 million or 8.4%.

Revenue from water distribution totalled U.S. $15.9 million as compared to U.S. $15.0 million during the same period in 2009, an increase of U.S. $0.9 million or 5.9%. The annual water distribution revenue was impacted by an increase of U.S. $0.6 million at the four Texas Silverleaf facilities primarily due to the implementation of rate increases, U.S. $0.3 million related to the acquisition of a facility in Galveston, Texas ("Galveston") and U.S. $0.1 million at the Litchfield Park Service Company ("LPSCo") facility due to a net increase in revenues from residential customers offset by decreased revenues from commercial customers in the first quarter of 2010, partially offset by decreased revenue of U.S. $0.1 million at the four facilities as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. $20.0 million, as compared to U.S. $18.0 million during the same period in 2009, an increase of U.S. $2.0 million or 11.1%. The annual wastewater treatment revenue was impacted by increased revenue, primarily due to the implementation of rate increases, of U.S. $1.0 million at the four Texas Silverleaf and Woodmark facilities. The Tall Timbers, LPSCo and Black Mountain facilities saw increased revenue of U.S. $1.0 million primarily due to the combination of the implementation of rate increases and higher residential customer demand. The annual wastewater treatment revenue was also impacted by increased revenue of U.S. $0.3 million related to the acquisition of Galveston as compared to the same period in 2009. These increases were partially offset by decreased wastewater treatment revenue of U.S. $0.1 million due to lower treated effluent revenue at the Gold Canyon facility as compared to the same period in 2009.

For the year ended December 31, 2010, operating expenses totalled U.S. $21.3 million, as compared to U.S. $20.1 million during the same period in 2009. Overall expenses increased U.S. $1.2 million or 6.0% as compared to the same period in 2009. Operating expenses increased U.S. $0.8 million as a result of increased wages, salary and other operating costs, $0.3 million related to rate case costs which, based on the rate case decisions, must be expensed, $0.2 million relating to legal expenses and U.S. $0.2 million as a result of increased equipment rental and transportation costs, partially offset by decreases of U.S. $0.1 million in reduced repair and maintenance expenses and $0.4 million in reduced contracted services expenses as compared to the same period in 2009.

During the year ended December 31, 2009, Liberty Water earned other income of U.S. $1.2 million on the disposition of excess land. During the year ended December 31, 2010, Liberty Water did not dispose of any significant land or other assets.

For the year ended December 31, 2010, Liberty Water's operating profit totalled U.S. $15.3 million as compared to U.S. $14.8 million in the same period in 2009, an increase of U.S. $0.5 million or 3.4%. Excluding other income, which includes a non-recurring gain on disposition of other assets (2009 - U.S. $1.2 million), operating profits increased by $1.6 million or 12.1%. Liberty Water's operating profit did not meet expectations for the year ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Measured in Canadian dollars, for the year ended December 31, 2010, Liberty Water's revenue totalled $37.8 million as compared to $38.5 million during the same period in 2009, a decrease of $0.7 million. Revenue from wastewater treatment totalled $20.7 million, as compared to $20.6 million during the same period in 2009, a decrease of $0.1 million. Revenue from water distribution totalled $16.5 million, as compared to $17.2 million during the same period in 2009, a decrease of $0.7 million. Liberty Water reported decreased revenue from operations of $3.6 million in 2010 as a result of the stronger Canadian dollar as compared to the same period in 2009.

Measured in Canadian dollars, for the year ended December 31, 2010, operating expenses totalled $22.1 million, as compared to $23.2 million during the same period in 2009. Liberty Water reported lower expenses from operations of $2.3 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the year ended December 31, 2010, Liberty Water's operating profit totalled $15.8 million as compared to $16.7 million in the same period in 2009, a decrease of $0.9 million or 5.5%. Excluding other income, which includes a non-recurring gain on disposition of other assets (2009 - $1.4 million), operating profits increased by $0.4 million or 2.3%. Liberty Water's operating profit did not meet expectations for the year ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

	Three months ended December 31		Three months ended December 31	
	2010	**2009**	**2010**	**2009**
Number of				
Wastewater connections			**35,420**	34,679
Wastewater treated (millions of gallons)			**500**	450
Water distribution connections			**37,666**	36,919
Water sold (millions of gallons)			**1,400**	1,400
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,258**	147,581		
Revenue				
Wastewater treatment	**5,334**	4,526	**5,436**	4,815
Water distribution	**4,096**	3,496	**4,174**	3,719
Other Revenue	**189**	142	**174**	153
	$ 9,619	$ 8,164	**$ 9,784**	$ 8,687
Expenses				
Operating expenses	**(5,143)**	(4,660)	**(5,245)**	(4,976)
Other income	**17**	(40)	**17**	(43)
Business Unit operating profit (including other income)	**$ 4,493**	$ 3,464	**$ 4,556**	$ 3,668

2010 Fourth Quarter Operating Results

During the quarter ended December 31, 2010, Liberty Water provided approximately 1.4 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 90 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2010, Liberty Water's revenue totalled U.S. $9.6 million as compared to U.S. $8.2 million during the same period in 2009, an increase of U.S. $1.4 million or 17.5%.

Revenue from water distribution totalled U.S. $4.1 million, as compared to U.S. $3.5 million during the same period in 2009, an increase of U.S. $0.6 million or 16.5%. The fourth quarter water distribution revenue was impacted by an increase of $0.1 million at the four Texas Silverleaf facilities primarily due to increased customer demand, U.S. $0.4 million at the LPSCo facility primarily due to the implementation of rate increases and U.S. $0.1 million related to the acquisition of Galveston as compared to the same period in 2009. In addition, the division experienced increased customer demand at four water distribution facilities as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. $5.3 million, as compared to U.S. $4.5 million during the same period in 2009, an increase of U.S. $0.8 million or 17.9%. The fourth quarter wastewater treatment revenue was impacted by increased revenue of U.S. $0.2 million at the four Texas Silverleaf and Tall Timbers facilities primarily due to increased customer demand, increased revenue of U.S. $0.6 at the Woodmark, Black Mountain and the LPSCo facilities, primarily due to the implementation of rate increases and U.S. $0.1 million related to the acquisition of Galveston as compared to the same period in 2009.

For the quarter ended December 31, 2010, operating expenses totalled U.S. $5.1 million, as compared to U.S. $4.7 million during the same period in 2009. Overall expenses increased U.S. $0.5 million or 10.4% as compared to the same period in 2009. Operating expenses increased due to increased legal, insurance and property taxes of U.S. $0.4 million, $0.3 million related to rate case costs which, based on the rate case decisions, must be expensed, partially offset by decreases of U.S. $0.1 million related to wages, salary and other operating costs and U.S. $0.1 million related to bad debt expense as compared to the same period in 2009. In the comparable period, the division capitalized U.S. $0.6 million related to rate case costs which were previously expensed due to the adoption of rate regulated accounting during the fourth quarter of 2009.

For the quarter ended December 31, 2010, Liberty Water's operating profit totalled U.S. $4.5 million as compared to U.S. $3.5 million in the same period in 2009, an increase of U.S. $1.0 million or 29.7%. Liberty Water's operating profit did not meet expectations for the three months ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Measured in Canadian dollars, for the quarter ended December 31, 2010, Liberty Water's revenue totalled $9.8 million, as compared to $8.7 million during the same period in 2009. Revenue from wastewater treatment totalled $5.4 million, as compared to $4.8 million during the same period in 2009, an increase of $0.6 million. Revenue from water distribution totalled $4.2 million, as compared to $3.7 million in the same period in 2009, an increase of $0.4 million. Liberty Water reported decreased revenue from operations of $0.3 million in the fourth quarter of 2010 as a result of the stronger Canadian dollar as compared to the same period in 2009.

Measured in Canadian dollars, for the quarter ended December 31, 2010, operating expenses totalled $5.2 million, as compared to $5.0 million during the same period in 2009. Liberty Water reported lower expenses from operations of $0.2 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the quarter ended December 31, 2010, Liberty Water's operating profit totalled $4.6 million as compared to $3.7 million in the same period in 2009, an increase of $0.9 million or 24.2%. Liberty Water's operating profit did not meet expectations for the three months ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Outlook – Liberty Water

Liberty Water expects continuing modest customer growth in 2011. Liberty Water provides water distribution and wastewater collection and treatment services, primarily in the southern and southwestern U.S. where communities have traditionally experienced long-term growth and that provide continuing future opportunities for organic growth.

Revenue increases from rate cases completed in Arizona and Texas on an annualized basis will contribute an additional U.S. $10.2 million in revenue in Liberty Water. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. $1.1 million in annual revenue requirement is expected to be concluded by the first quarter of 2011.

Liberty Water continues to work with key stakeholders, including regulators, to help manage issues related to the issuance of decisions in its rate cases in a timely manner.

Completed Rate Cases	Date of Rate Increases	Annual U.S. $ Revenue Increase Requested	Annual U.S. $ Revenue Increase Granted
Facility			
Arizona			
Black Mountain	October 2010	$ 1.0 million	$ 0.7 million
Litchfield Park Service Company	December 2010	$ 11.6 million	$ 7.1 million
Rio Rico	February 2011	$ 1.6 million	$ 0.9 million
Texas			
Texas Utilities (Silverleaf – 4 utilities)	October 2009	$ 1.2 million	$ 1.2 million
Tall Timbers	July 2009	$ 0.2 million	$ 0.2 million
Woodmark	January 2010	$ 0.1 million	$ 0.1 million

Rate Cases Awaiting Recommended Order & Opinion	Estimated Annual U.S. $ Revenue Increase Requested
Facility	
Arizona	
Bella Vista, Northern and Southern Sunrise	$ 1.1 million

Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Water monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

In Arizona, the ACC requires a full regulatory process for all rate cases using a historic test year. On August 5, 2010, Liberty Water received a recommended order ("ROO") for its Black Mountain Sewer Company recommending an annualized rate increase of approximately $0.7 million. The ROO was approved in entirety at the Commission's open meeting held in August.

On October 5, 2010, Liberty Water received a ROO for the LPSCo facility proposing an annualized revenue increase of $8.1 million. At the ACC open meeting held on December 10, 2010 to consider the ROO, the approved revenue increase was reduced to $7.1 million. As part of the LPSCo ROO, the rate increase will be phased in with 50% of the increase being applied in the first 6 months, increasing to 75% for 6 months thereafter, and 100% of the rate increase being realized from month 12 forward. LPSCo is entitled to recover the foregone revenue from the phase in of rates including carrying charges under terms to be determined during the second phase of the LPSCo rate case which focuses on amounts charged for hookup fees. This phase is expected to occur later in 2011.

On December 11, 2011, the ACC approved an order authorizing an annualized rate increase of $0.9 million for Rio Rico Utilities Inc., effective February 1, 2011. It is anticipated that the regulatory review of the proposed rates and tariffs for Bella Vista, Northern Sunrise, and Southern Sunrise will be completed in Q1 2011.

In Texas, the Texas Commission on Environmental Quality ("TCEQ") allows the utility's customers a period of 90 days from the effective date of the proposed rates to object to the imposition of interim rates pending final rates determination. If greater than 10% of a specific Texas utility's customers object to the new proposed rates, the proposed rates would be subjected to a full regulatory hearing process administered by the TCEQ in order to finalize the rates. If fewer than 10% of the customers record an objection to the proposed rates, those proposed rates are likely to be adopted and declared final as proposed. Any difference between the interim rates charged and collected and the final rates as approved by TCEQ will be subject to a retroactive adjustment and refund on the customers' subsequent monthly bill.

Liberty Water entered into negotiated settlements with the customers of the Texas Silverleaf and Tall Timbers facilities, resulting in the achievement of the full estimated annualized revenue increase of $1.2 million and $0.2 million, respectively. The Woodmark facility did not receive objections from 10% of the customer base and also achieved the full estimated annualized revenue increase of $0.1 million.

Liberty Energy

LIBERTY ENERGY

Liberty Energy's business strategy is to build its portfolio of electric and natural gas distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best-in-class customer care for its utility ratepayers.

In 2009, Liberty Energy announced plans to acquire the California Utility, in partnership with Emera. The acquisition was approved by both the CPUC and the Public Utilities Commission of Nevada in the fourth quarter of 2010. The transaction was completed on January 1, 2011 for a purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. The acquisition was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility, entered into on December 29, 2010. Liberty Energy's ownership share of the cost of acquisition of the California Utility was primarily funded through the proceeds of subscription receipts held by Emera for 8.532 million APUC common shares at a price of $3.25 per share.

On December 9, 2010, Liberty Energy entered into agreements to acquire all issued and outstanding shares of Granite State, a regulated New Hampshire electric utility, and EnergyNorth, a regulated New Hampshire natural gas utility from National Grid for total consideration of U.S. $285.0 million which represents a multiple of 1.136 times the aggregate expected regulatory assets. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. Granite State's load and customer counts have shown a consistent 1.6% compounded annual growth over the past 10 years. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. EnergyNorth has a well diversified customer base with no individual customer accounting for more than 3% of gas volumes delivered. Both Granite State and EnergyNorth have capable and experienced work forces which will continue with the businesses following closing.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011. Financing of the acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Energy is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate premium of 5% to the closing price on December 8, 2010. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost of acquisition of Granite State and EnergyNorth. The issuance of these subscription receipts is subject to regulatory approval.

APUC: Corporate

	Three months ended December 31		Twelve months ended December 31	
	2010	2009	2010	2009
Corporate and other expenses:				
Administrative expenses and management costs	**5,126**	2,742	**14,886**	11,562
Write down of property and notes	**2,492**	6,457	**2,492**	6,457
Management internalization expense	**-**	4,693	**-**	4,693
Other corporatization expenses	**-**	3,460	**-**	3,460
Loss / (Gain) on foreign exchange	**(54)**	(258)	**(528)**	(1,261)
Interest expense	**6,719**	5,645	**25,612**	21,387
Interest, dividend and other Income	**(985)**	(738)	**(3,599)**	(2,986)
Loss (gain) on derivative financial instruments	**(1,842)**	(1,515)	**1,103**	(17,318)
Income tax recovery	**(15,539)**	(10,662)	**(20,228)**	(17,927)

2010 Annual Corporate and Other Expenses

During the year ended December 31, 2010, management and administrative expenses totalled $14.9 million, as compared to $11.6 million in the same period in 2009. The expense increase in the twelve months ended December 31, 2010 results from increased capital taxes resulting from APUC's effective conversion to a corporation in 2009, increased legal, audit, tax and other professional fees associated with APUC being registered with the SEC as a foreign private issuer, Algonquin continuing to be registered as reporting issuer in 2010, the corporate reorganization of the Liberty Water division and additional salaries related to the internalization of management and administering APUC's operations as compared to the same period in 2009. In the comparable period, administrative expenses of $2.2 million were considered costs related to APUC's conversion to a corporation and classified as other corporatization expenses.

In December 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1.8 million representing the difference between the carrying value of the assets and their fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities. In December 2010, the equipment at the Crossroads thermal facility in New Jersey met the conditions for *"asset held for sale"*. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

In the comparable period in 2009, APCo decided to dispose of its investments in its remaining LFG facilities and its 50% ownership in the Drayton Valley facility. As a result of testing its investments for recoverability using a net realizable value valuation technique, APCo determined that these assets were impaired as at December 31, 2009. Accordingly, for the year ended December 31, 2009, APCo recognized an impairment charge of $1.1 million against the outstanding principal balance of a note receivable related to its LFG operations. APCo also wrote down the carrying value of its remaining LFG facilities and its 50% investment in the Valley Power facility to their estimated current fair value. This resulted in a write-down of property and equipment of $4,854 in the period representing the difference between the carrying value of the assets and their net realizable values.

During the year ended December 31, 2010, there were no costs recorded in association with management internalization. During the comparable period in 2009, APUC recorded an expense of $4.7 million with regards to an agreement to acquire the Manager's interest in the management services agreement and internalize management in exchange for shares of APUC. On December 21, 2009, the Board ratified an agreement in principal with the shareholders of APMI to acquire the management contract and internalize management. Senior management expenses have been recorded within the Administrative Expense category on a go forward basis.

During the year ended December 31, 2010, there were no costs recorded associated with converting Algonquin to a corporation. During the comparable period, APUC recorded an expense of $3.5 million associated with costs of converting the Fund to a corporation.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and working capital balances held by Canadian operating entities and do not impact current cash position. During the twelve months ended December 31, 2010, APUC classified all of its power generation operating facilities based in the U.S. as self-sustaining. As a result, foreign exchange translation gains and losses of U.S. denominated debt and working capital balances in these U.S. operating entities after January 1, 2010 no longer flow though the consolidated statement of operations. For the twelve months ended December 31, 2010, APUC reported a foreign exchange gain in relation to U.S. assets held by Canadian entities of $0.5 million as compared to a gain of $1.3 million during the same period in 2009. The twelve months ended December 31, 2010 experienced a decrease in value of the U.S. dollar of 5.4% which resulted in unrealized gains on APUC's U.S. dollar denominated debt and working capital balances held by Canadian entities. In the comparable period in 2009, APUC's power generation operating facilities based in the U.S. were classified as integrated and the decrease in the value of the U.S. dollar of 14.2% experienced in the period resulted in unrealized translation gains on APUC's U.S. dollar denominated debt and working capital balances held by its integrated U.S. operating facilities.

For the twelve months ended December 31, 2010, interest expense totalled $25.6 million as compared to $21.4 million in the same period in 2009. Interest expense increased as a result of higher levels of convertible debentures and increased interest rates charged on variable rate debt, partially offset by decreased interest expense resulting from lower average borrowings on APUC's variable interest rate credit facilities, as compared to the prior year.

For the twelve months ended December 31, 2010, interest, dividend and other income totalled $3.6 million as compared to $3.0 million in the same period in 2009. Interest, dividend and other income primarily consists of dividends from APUC's share investments in the Kirkland and Cochrane facilities and interest related to APUC's subordinated debt interest in the Red Lily I project. The income earned on the investments in the Kirkland and Cochrane facilities was previously allocated to interest and other income in the Thermal Energy division.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on foreign exchange forward contracts, interest rate swaps and forward energy contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $20.2 million was recorded in the twelve months ended December 31, 2010, as compared to a recovery of $17.9 million during the same period in 2009. There are two primary reasons for the income tax recovery for the year. First, in the fourth quarter of 2010, APUC completed the Liberty Water portion of its overall capital structure project. The objective of the capital structure project was to ensure that APUC's operating subsidiaries each have a capital structure that is appropriate for the business sector and functional currency in which it operates. Therefore as part of this process, APUC converted certain Canadian dollar denominated intercompany notes with Liberty Water into US dollar denominated notes resulting in a realized foreign exchange loss for tax purposes, thereby creating a future tax asset of approximately $12 million that is now available as additional tax shelter in future years. Secondly, on October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. Included in future income tax recoveries for the year ended December 31, 2010 is $6.6 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2010 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2010, management and administrative expenses totalled $5.1 million, as compared to $2.7 million in the same period in 2009. The expense increase in the three months ended December 31, 2010 results from those factors identified in the discussion of the annual expense noted above as compared to the same period in 2009.

In December 2010, APCo wrote down its investment in three small hydro facilities and determined that the equipment at the Crossroads thermal facility in New Jersey met the conditions for *“asset held for sale”*. See the discussion in the annual corporate and other expenses section above for details related to this expense.

In the comparable period in 2009, APCo decided to dispose of its investments in its remaining LFG facilities and its 50% ownership in the Drayton Valley facility. See the discussion in the annual corporate and other expenses section above for details related to this expense.

During the year ended December 31, 2010, there were no costs recorded in association with management internalization. During the comparable period in 2009, APUC recorded an expense of $4.7 million with regards to an agreement to acquire the Manager’s interest in the management services agreement and internalize management. See the discussion in the annual corporate and other expenses section above for details related to this expense.

During the year ended December 31, 2010, there were no costs recorded associated with converting the Fund to a corporation. During the comparable period, APUC recorded an expense of $3.5 million associated with costs of converting the Fund to a corporation.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and working capital balances held by Canadian operating entities and do not impact current cash position. For the three months ended December 31, 2010, APUC reported a foreign exchange gain of $0.1 million as compared to a gain of $0.3 million during the same period in 2009. The three months ended December 31, 2010 experienced a decrease in value of the U.S. dollar of 3.3% which resulted in unrealized gains on APUC’s U.S. dollar denominated debt and working capital balances held by Canadian entities. In the comparable period in 2009, APUC’s power generation operating facilities based in the U.S. were classified as integrated and the decrease in the value of the U.S. dollar of 2.8% experienced in the quarter resulted in unrealized translation gains on APUC’s U.S. dollar denominated debt and working capital balances held by its integrated U.S. operating facilities.

For the quarter ended December 31, 2010, interest expense totalled $6.7 million as compared to $5.6 million in the same period in 2009. Interest expense increased as a result of higher levels of convertible debentures, and increased average interest rates charged on APUC’s variable interest rate credit facilities, partially offset by lower average borrowings on APUC’s variable interest rate credit facilities, as compared to the prior year.

For the quarter ended December 31, 2010, interest, dividend and other income totalled $1.0 million as compared to $0.7 million in the same period in 2009. Interest, dividend and other income primarily consists of dividends from APUC’s share investment in the Kirkland and Cochrane facilities and interest related to APUC’s subordinated debt interest in the Red Lily I project. The income earned on the investments in the Kirkland and Cochrane facilities was previously allocated to interest and other income in the Thermal Energy division.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on foreign exchange forward contracts, interest rate swaps and forward energy contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC’s current cash position.

An income tax recovery of $15.5 million was recorded in the three months ended December 31, 2010, as compared to a recovery of $10.7 million during the same period in 2009. The income tax recovery for the three months ended December 31, 2010 results from those factors identified in the discussion of the annual income tax expense noted above. Included in future income tax recoveries for the three months ended December 31, 2010 is $2.4 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense which are non-cash and derived from a number of non-operating factors, accounting methods and assumptions. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended December 31		Twelve months ended December 31	
	2010	2009	2010	2009
Net earnings (loss)	**$ 16,888**	$ (1,366)	**$ 19,639**	$ 31,257
Add:				
Income tax recovery	**(15,539)**	(10,662)	**(20,228)**	(17,927)
Interest expense	**6,719**	5,645	**25,612**	21,387
Write down of property, plant and equipment	**2,492**	5,354	**2,492**	5,354
Write down of note receivable	**-**	1,103	**-**	1,103
Management internalization costs	**-**	4,693	**-**	4,693
Other corporatization costs	**-**	3,460	**-**	3,460
(Gain) / loss on derivative financial instruments	**(1,842)**	(1,515)	**1,103**	(17,318)
Gain on foreign exchange	**(54)**	(258)	**(528)**	(1,261)
Amortization	**11,900**	11,350	**46,573**	45,883
Other	**129**	223	**444**	2,737
Adjusted EBITDA	**$ 20,693**	$ 18,027	**$ 75,107**	$ 79,368

For the year ended December 31, 2010, Adjusted EBITDA totalled $75.1 million as compared to $79.4 million, a net decrease of $4.3 million or 5.4% as compared to the same period in 2009. For the quarter ended December 31, 2010, Adjusted EBITDA totalled $20.7 million as compared to $18.0 million, an increase of $2.7 million or 14.8% as compared to the same period in 2009. The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

	Three months ended December 31 2010	Twelve months ended December 31 2010
Comparative Prior Period Adjusted EBITDA	$ 18,027	$ 79,368
Significant Changes:		
Administration and management costs	(2,400)	(3,300)
Hydro Renewable – primarily due to lower hydrology	200	(3,400)
Lower results from stronger Canadian dollar	(100)	(3,000)
Windsor Locks – change in operating model	-	(2,300)
St. Leon - primarily due to a lower wind resource	800	(1,900)
EFW – impact of shutdown	700	(1,700)
Liberty Water gain on sale of excess land	-	(1,400)
Acquisition of Tinker Hydro in Q1 2010	2,800	9,900
Red Lily – development fees	600	2,100
Liberty Water revenue increases primarily due to rate case approvals	1,600	2,000
Other	(1,534)	(1,261)
Current Period Adjusted EBITDA	$ 20,693	$ 75,107

Reconciliation of adjusted net earnings to net earnings

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. APUC uses adjusted net earnings to assess the performance of APUC without the effects of gains or losses on foreign exchange, foreign exchange forward contracts and interest rate swaps as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of APUC's businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended December 31		Twelve months ended December 31	
	2010	**2009**	**2010**	**2009**
Net earnings (loss)	**$ 16,888**	$ (1,366)	**$ 19,639**	$ 31,257
Add:				
Loss (gain) on derivative financial instruments, net of tax	**(1,292)**	(757)	**(1,688)**	(13,378)
Write down of property and notes, net of tax	**2,492**	6,379	**2,492**	6,379
Management internalization expense, net of tax	**-**	4,693	**-**	4,693
Other corporatization expenses, net of tax	**-**	2,813	**-**	2,813
Gain on foreign exchange, net of tax	**(54)**	(258)	**(528)**	(1,261)
Adjusted net earnings	**$ 18,034**	$ 11,504	**$ 19,915**	$ 30,503
Adjusted net earnings per share unit	**$ 0.19**	$ 0.14	**$ 0.21**	$ 0.38

For the year ended December 31, 2010, adjusted net earnings totalled $19.9 million as compared to $30.5 million, a decrease of $10.6 million as compared to the same period in 2009. The decrease in adjusted net earnings in the twelve months ended December 31, 2010 is primarily due to higher interest expense and management and administrative expenses as compared to the same period in 2009.

For the three months ended December 31, 2010, adjusted net earnings totalled $18.0 million as compared to adjusted net earnings of $11.5 million, an increase of $6.5 million as compared to the same period in 2009. The increase in adjusted net earnings in the three months ended December 31, 2010 is primarily due to increased earnings from operations and increased future income tax recoveries, partially offset by increased interest expense as compared to the same period in 2009.

SUMMARY OF PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

	Three months ended December 31		Twelve months ended December 31	
	2010	2009	2010	2009
APCo				
Renewable Energy Division				
Capital expenditures	**$ 979**	$ 480	**$ 2,331**	$ 1,114
Acquisition of operating entities	**-**	-	**40,281**	-
Total	**$ 979**	$ 480	**$ 42,612**	$ 1,114
Thermal Energy Division				
Capital expenditures	**$ 434**	$ 664	**$ 11,596**	$ 3,521
Total	**$ 434**	$ 664	**$ 11,596**	$ 3,521
LIBERTY WATER				
Capital Investment in regulatory assets	**$ 4,584**	$ (427)	**$ 6,644**	$ 6,174
Acquisition of operating entities	**-**	-	**2,121**	-
	$ 4,584	$ (427)	**$ 8,765**	$ 6,174
LIBERTY ENERGY				
Capital Investment in regulatory assets	**$ -**	$ -	**$ -**	$ -
Acquisition of operating entities	**3,123**	317	**3,123**	1,177
	$ 3,122	**$ 317**	**$ 3,123**	**$ 1,177**
Consolidated (includes Corporate)				
Capital expenditures	**$ 1,595**	$ 1,144	**$ 14,187**	$ 4,742
Capital investment in regulatory assets	**4,584**	(427)	**6,644**	6,174
Acquisition of operating entities	**3,123**	317	**45,524**	1,177
Total	**$ 9,302**	$ 1,034	**$ 66,240**	$ 12,093

APUC's consolidated capital expenditures in the twelve months ended December 31, 2010 increased as compared to the same period in 2009 primarily due to the major capital upgrades completed at the EFW facility, the acquisition of the Tinker Assets and the Energy Services Business, costs associated with the acquisition by Liberty Energy of the California Utility and the acquisition by Liberty Water of a water distribution and wastewater treatment facility in Texas.

Property, plant and equipment expenditures for 2011 fiscal year are anticipated to be between $27 million and $34 million, including approximately $8.0 million related to ongoing requirements by Liberty Water, $3.0 million related to Liberty Energy's share of ongoing requirements at the California Utility, $6.5 million related to the APCo Thermal division, and $8.0 million related to the APCo Renewable Energy division.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2010 Annual Property Plant and Equipment Expenditures

During the year ended December 31, 2010, APCo incurred capital expenditures of $14.2 million, as compared to $4.7 million during the comparable period in 2009. APCo also invested $40.2 million to acquire operating assets/entities during the twelve months ended December 31, 2010, as compared to nil million during the comparable period in 2009.

During the twelve months ended December 31, 2010, APCo Renewable Energy division's capital expenditures were $2.3 million, as compared to $1.1 million in the comparable period in 2009. There were no individual projects in excess of $0.5 million initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets relate to the Tinker Assets located in New Brunswick and Maine.

During the twelve months ended December 31, 2010, APCo Thermal Energy division's capital primarily relate to the EFW facility where major maintenance was completed subsequent to the end of the quarter. In the comparable period, the expenditures primarily related to minor capital projects at the hydro-mulch facility and the EFW facility.

During the twelve months ended December 31, 2010, Liberty Water invested maintenance capital of $6.6 million into regulatory assets, as compared to an investment of $6.2 million in the comparable period. During the twelve months ended December 31, 2010, Liberty Water acquired a water and wastewater utility near Galveston

Texas for approximately $2.0 million. In the comparable period in 2009, Liberty Water's expenditures primarily related to the completion and commissioning of projects initiated in 2008.

During the twelve months ended December 31, 2010, Liberty Energy incurred costs associated with the acquisition by Liberty Energy of the California Utility of $3.0 million, as compared to $1.2 million in the comparable period.

As previously noted, these investments have been included in the rate case applications completed as well as those currently underway. In the comparable period, the expenditures primarily related to investment in additional wells, engineering work regarding wastewater treatment operations and arsenic treatment at the LPSCo facility. The expenditures in the comparable period are included in the rate case applications which are currently in process.

2010 Four Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2010, APCo incurred capital expenditures of $1.6 million, as compared to $1.1 million during the comparable period in 2009.

During the three months ended December 31, 2010, APCo Renewable Energy division's capital expenditures were not significant, consistent with the comparable period in 2009.

During the three months ended December 31, 2010, APCo Thermal Energy division's capital expenditures were not significant, consistent with the comparable period in 2009.

During the three months ended December 31, 2010, Liberty Water invested maintenance capital of $4.6 million into regulatory assets, as compared to $0.4 million in the comparable period.

During the three months ended December 31, 2010, Liberty Energy incurred costs associated with the acquisition by Liberty Energy of the Calpeco facility of $3.0 million, as compared to $0.3 million in the comparable period.

LIQUIDITY AND CAPITAL RESERVES

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2010 under the senior banking Facility:

	2010 Q4	2010 Q3	2010 Q2	2010 Q1	2009 Q4
Committed and available Facility	$ 142,000*	$ 163,400	$ 162,800	$ 177,950	$ 179,500
Funds Drawn on Facility	(64,500)	(108,900)	(102,800)	(91,650)	(94,000)
Letters of Credit issued	(33,100)	(33,800)	(34,600)	(32,400)	(33,100)
Remaining available Facility	**$ 44,400***	**$ 20,700**	**$ 25,400**	**$ 53,900**	**$ 52,400**
Cash on Hand	5,100	3,100	2,400	750	2,800
Total liquidity and capital reserves	**$ 49,500**	**$ 23,800**	**$ 27,800**	**$ 54,650**	**$ 55,200**

* Reflects availability under a new three year Facility announced on January 14, 2011.

As at and for the period ended December 31, 2010, APUC and Algonquin are in compliance with the covenants under the Facility.

As at December 31, 2010, CAD $64.5 million had been drawn on the Facilities as compared to CAD $94.0 million as at December 31, 2009. On December 22, 2010, Liberty Water obtained a U.S. $50 million long-term private placement financing. The notes are senior unsecured with a 10 year term bearing interest at 5.6%. The notes are interest only until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. Proceeds were used to reduce amounts outstanding under the Facility. In addition to amounts actually drawn, there was $33.1 million in letters of credit outstanding as at December 31, 2010.

Subsequent to the year end, Algonquin concluded negotiations with its bank syndicate on the renewal of the Facility for a three year term with a maturity date of February 14, 2014. Algonquin reduced the total of the Facility as part of its capital structure initiatives to term out some of the short-term borrowings under the Facility.

Under the terms of the new banking agreement, as at December 31, 2010, Algonquin had $44.4 million of committed and available bank facilities remaining and $5.1 million of cash resulting in $49.5 million of total liquidity and capital reserves.

APUC expects to continue to reduce its level of short term borrowings under the Facility through obtaining appropriate long term debt through refinancing certain project specific financings or additional medium to long-term notes. APUC has received and is currently assessing several financing offers to term out the remainder of its short term bank credit facility and project debt coming due in the next three quarters. APUC anticipates concluding its assessments on these offers by the second quarter of 2011.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of December 31, 2010 is shown below:

	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Long-term debt obligations[1]	$ 259,131	$ 70,490	$ 3,238	$ 68,395	$ 117,008
Convertible Debentures	$ 185,342	-	-	62,469	122,873
Interest on long-term debt obligations	$ 164,830	25,670	48,198	35,889	55,073
Purchase obligations	$ 33,506	33,506	-	-	-
Derivative financial instruments:					
Currency forward	$ 45	45	-	-	-
Interest rate swap	$ 5,439	1,959	2,504	976	-
Energy forward contracts	$ 378	378	-	-	-
Capital lease obligations	$ 523	212	243	68	-
Other obligations	$ 9,255	466	931	931	6,927
Total obligations	$ 658,449	$ 132,726	$ 55,114	$ 168,728	$ 301,881

Long term obligations include regular payments related to long term debt and other obligations.

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

On October 27, 2009, all of Algonquin's trust units were exchanged for shares of APUC that began to be publicly traded on the Toronto Stock Exchange ("TSX") while Algonquin's trust units concurrently ceased trading on the TSX.

As at December 31, 2010, APUC had 95,422,778 issued and outstanding shares on a fully diluted basis. On January 1, 2011, following Emera's exercise of its subscription receipts, APUC had 103,945,778 issued and outstanding shares on a fully diluted basis. The shares issued to Emera were in connection with APUC's partnership with Emera entered into on April 23, 2009 wherein APUC agreed to issue approximately 8.5 million shares of APUC at a price of $3.25 per share to finance a portion of the acquisition of the California Utility.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled: to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC, to receive a pro rata share of any remaining property and assets of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

In 2008, Algonquin entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG"), which was the manager of Highground and a related party of Algonquin controlled by the shareholders of Algonquin Power Management Inc., the former manager of Algonquin ("APMI" or the "Manager"). Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and Algonquin issued equity in the form of trust units to the Highground shareholders and CJIG.

In 2009, APUC's consideration received from the acquisition exceeded $26,970, the minimum contemplated under the agreements, and, as a result APUC is entitled to 50% of any additional proceeds from the assets formerly owned by Highground. CJIG is entitled to the remaining 50% of any proceeds in excess of the minimum amount. During the twelve months ended December 31, 2010, APUC received $0.2 million (2009 - $1.0 million) from CJIG as APUC's share of the 50% of additional proceeds from the further liquidation of the assets held by Highground. This has been recorded as an increased amount assigned to the equity originally issued.

The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having an approximate principal amount of $2.2 million. Debt representing $1,000 matured in December 2010 and the balance of the debt matures in the fourth quarter of 2012. Negotiations with the borrower of the $1,000 are currently underway to secure repayment. APUC's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded when received as additional proceeds from the issuance of equity.

On December 21, 2009, the Board reached an agreement with the shareholders of APMI to internalize all management functions of APCo which were provided by the Manager. At a meeting of the shareholders held in June 2010, shareholders approved the issuance of shares in respect of the internalization of management. As a result, APUC acquired the interest previously held by APMI in the management services agreement through the issuance of 1,180,180 APUC shares during the quarter ended June 30, 2010. The management services agreement has since been terminated.

In July 2004, the Fund issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on July 31, 2011 ("Series 1 Debentures"). The Series 1 Debentures bore interest at 6.65% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $10.65 per trust unit, being a ratio of approximately 93.9 trust units for each $1,000 principal. On October 27, 2009, there were 84,964 convertible debentures outstanding with a face value of $84,964.

Pursuant to the CD Exchange Offer, on October 27, 2009, $63,755 of the outstanding Series 1 Debentures were exchanged for convertible debentures bearing interest at 7.5%, maturing on November 30, 2014 ("Series 1A Debentures") convertible unsecured subordinated debentures in a principal amount of $66,943. The remaining Series 1 Debentures having a face value of $21,209, not converted to Series 1A Debentures pursuant to the CD Exchange Offer, were exchanged for 6,607,027 shares of APUC.

The Series 1A Debentures pay interest semi-annually in arrears on January 1 and July 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $4.08 per share, being a ratio of approximately 245.1 shares for each $1,000 principal. The Series 1A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.10 (125% of the conversion price of $4.08). During the period of January 2, 2012 until the debenture's maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional shares.

During the three months ended December 31, 2010, a principal amount of $982 of Series 1A Debentures were converted into 240,646 shares of APUC and a principal amount of $4,473 Series 1A Debentures were converted into 1,096,335 shares of APUC during the twelve months ended December 31, 2010. On December 31, 2010, there were 62,470 Series 1A Debentures outstanding with a face value of $62,470. Subsequent to the end of the quarter, $72 Series 1A Debentures were converted to 17,558 shares of APUC.

In November 2006, the Fund issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016 ("Series 2 Debentures"). The Series 2 Debentures bore interest at 6.2% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $11.00 per trust unit, being a ratio of approximately 90.9 trust units for each $1,000 principal. During the three months ended December 31, 2009 and prior to October 27, 2009, Series 2 Debentures valued at $33,000 were exchanged into 3,000 trust units. These trust units were converted to shares of APUC as a result of the Unit Exchange. On October 27, 2009, there were 59,967 Series 2 Debentures outstanding with a face value of $59,967.

Pursuant to the CD Exchange Offer, on October 27, 2009, all of the outstanding Series 2 Debentures were exchanged for convertible unsecured subordinated debentures bearing interest at 6.35%, maturing on November 30, 2016 ("Series 2A Debentures") in a principal amount of $59,967. The Series 2A Debentures pay interest semi-annually in arrears on April 1 and October 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $6.00 per share, being a ratio of approximately 166.7 shares for each $1,000 principal. The Series 2A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $7.50 (125% of the conversion price of $6.00). During the period of January 2, 2012 until the debenture's maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional shares. On December 31, 2010, there were 59,967 Series 2A Debentures outstanding with a face value of $59,967.

On December 2, 2009, APUC issued 63,250 convertible unsecured debentures at a price of $1,000 for each debenture maturing on June 30, 2017 ("Series 3 Debentures"). APUC received net proceeds of $60.7 million after underwriting expenses and before additional issuance costs (gross proceeds of $63.3 million). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures' maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional shares.

On December 31, 2009, there were 63,250 Series 3 Debentures outstanding with a face value of $63,250.

During the three months and year ended December 31, 2010, a principal amount of $345 of Series 3 Debentures was converted into 82,142 shares APUC. On December 31, 2010, there were 62,905 Series 3 Debentures outstanding with a face value of $62,905. Subsequent to the end of the quarter, $105 Series 3 Debentures were converted to 24,999 shares.

SHAREHOLDERS' RIGHTS PLAN

APUC has adopted a Shareholders' Rights Plan (the "Rights Plan"). The Rights Plan is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The TSX has accepted notice for filing of the Rights Plan and the Rights Plan was approved by shareholders at the Meeting until the termination of the annual general meeting of the Shareholders of APUC in 2013 or its termination under the terms of the of Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. Until the occurrence of certain specific events, the rights will trade with the shares of APUC and be represented by certificates representing the shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent or more of the outstanding shares of APUC without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional shares of APUC at a fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Rights Plan, a Permitted Bid is a bid made to all shareholders for all of their shares on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent of the outstanding shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the shares but must extend the bid for a further ten days to allow all other shareholders to tender.

STOCK OPTION PLAN

On June 23, 2010, APUC's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. An option holder may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the "In-The-Money

Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by APUC in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

On August 12, 2010, the Board approved the grant of 1,102,041 options to select senior executives of APUC. The options allow for the purchase of common shares at a price of $4.05, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2011, 2012 and 2013. Options may be exercised up to eight years following the date of grant.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. At December 31, 2010, APUC recorded $108 (2009 - $nil) in compensation expense. As at December 31, 2010, there was $562 (2009 - $nil) of total unrecognized compensation costs related to non-vested options granted under the Plan. The cost is expected to be recognized over a period of 1.9 years.

No share options were exercised in 2010 or exercisable at December 31, 2010. The intrinsic value of the 1,102,041 non-vested shares as at December 31, 2010 was $1,069 (2009 – nil).

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

- Up to December 21, 2009, APMI provided management services to the Fund including advice and consultation concerning business planning, support, guidance and policy making and general management services. On December 21, 2009, the Board reached an agreement ("Management Internalization Agreement") with APMI to internalize all management functions of Algonquin which were provided by APMI. APUC acquired APMI's interest in the management services agreement, with consideration paid in the form of issuance of 1,158,748 APUC shares (the "Shares"). For accounting purposes, the expense has been measured at $4,693 using a price for each Share of $4.03, the adjusted closing market price on December 21 2009, the date the agreement was ratified. Therefore, for the three and twelve months ended December 31, 2010, APMI was not paid a management fee. For the three and twelve months ended December 31, 2009, APMI was paid on a cost recovery basis for costs incurred and charged $211 and $850 respectively.

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and twelve months ended December 31, 2010 were $82 (2009 - $82) and $327 (2009 - $331) respectively. Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. In 2004, APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the three and twelve months ended December 31, 2010, APUC incurred costs in connection with the use of the aircraft of $60 (2009 - $60) and $430 (2009 - $367), respectively, and amortization expense related to the advance against expense reimbursements of $13 (2009 - $35) and $112 (2009 - $153), respectively. At December 31, 2010, the remaining amount of the advance was $554 (2009 - $666) and is recorded in other assets.
- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a five year period commencing June 17, 2008 growing to a maximum of 10% by year fifteen. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount equal to the debt service on the outstanding debt in respect of such period. The related party holders of the Class B units are entitled to cash distributions of $77 (2009 - $71) and $266 (2009 - $292) for the three and twelve months ended December 31, 2010, respectively.
- During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1.8 million of which APUC agreed to pay APMI $0.1 million. This amount has been accrued and included in accounts payable on the consolidated balance sheet.
- Pursuant to the agreement entered into on June 27, 2008 between Algonquin, Highground and CJIG, APMI was entitled to a fee of approximately $240 from Algonquin. This fee was paid in 2009.
- APUC has operation and maintenance service agreements with three hydroelectric generating facilities owned by affiliates of APMI. As a result of these agreements, APUC employees operate these hydroelectric generating facilities owned by affiliates of APMI. These facilities are charged on a cost recovery basis for time and material incurred at these sites.
- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years to a maximum of 2% after twenty-five years. APUC has agreed to acquire APMI's interest in this royalty for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine the portion of such fee which will be paid following commercial operation of the facility. APUC received and recognized $0.2 million in other revenue related to this fee in the twelve months ended December 31, 2010.
- The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.
- Under these arrangements, as at December 31, 2010 the amount due from the above related party transactions was $718 (2009 - $1,028) and amounts due to related parties was $901 (2009 - $827).
- A member of the Board of Directors of APUC is an executive at Emera. A contract with a subsidiary of Emera to purchase energy on ISO-NE and provide scheduling services on ISO-NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired in the three months ended March 31, 2010 and was not renewed. As a result of this contract, during the three months ended March 31, 2010, a subsidiary of Emera provided services to and

purchased energy on ISO-NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of $1,368 (2009 - $nil) which was included as an operating expense on the consolidated statement of operations.

- On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of MPS. Subsequent to the date of this acquisition, the Energy Services Business sold electricity of U.S. $144 (2009 – nil) to MPS.
- During the period ended June 30, 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO-NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2010 APUC paid U.S. $69 (2009 - $nil) and U.S. $196 (2009 - $nil) in relation to this contract. In the same period, APUC issued a letter of credit to a subsidiary of Emera in an amount of U.S. $500 in conjunction with this contract. Subsequent to December 31, 2010, this letter of credit was replaced with a corporate guarantee.
- APUC believes that the transactions with Emera noted above were in accordance with normal commercial terms.

Business associations with APMI and Senior Executives.

There are a number of continuing business relationships between APUC and one of Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. The Board has initiated a process to review all of the remaining business associations with Senior Executives, APMI and related affiliates in order to reduce, streamline and simplify these relationships. Any acquisitions associated with this process will only proceed if they are expected to be accretive to APUC.

The Board has formed a special committee and intends to engage independent consultants to assist with this process and expects to conclude this process over the next three months.

The co-owned assets and remaining business associations consist of the following:

i) Rattlebrook hydroelectric generating facility

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 27.5% by Senior Executives and the remaining percentage by third parties.

ii) St. Leon wind power generating facility

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives.

iii) Brampton Cogeneration Inc.

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $100 in relation to the development of this project. As of December 31, 2010, this amount is accrued and included in accounts payable on the consolidated balance sheet.

iv) Long Sault Rapids hydroelectric generating facility

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.

v) Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2010, $554 of the advance remained.

vi) Office lease

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The lease expires in December 31, 2012. Based on a review of the real estate leasing market at the time, APUC believes the lease was on terms equivalent to fair market value for prime office space of similar size and quality.

vii) Operations services

Staff managed by APUC operate an additional three hydroelectric generating facilities where Senior Executives hold an interest. Each facility is charged on a full cost recovery basis for these staff. Effective January 1, 2011, management of these facilities is being undertaken by a non-APUC related entity. APUC is providing some transition services to the non-APUC entity.

viii) Sanger construction management

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI.

ix) Clean Power Income Fund

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of December 31, 2010 this amount is accrued and included in accounts payable on the consolidated balance sheet.

x) Red Lily I

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. APUC has agreed to acquire APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility.

xi) Trafalgar

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Algonquin moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar had previously won a $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was then reached between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal costs with the proceeds from the lawsuits being shared after reimbursement of legal costs. The Second Circuit Court of Appeals recently dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Water maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, any credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 45% of EBITDA and 60% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately $15.5 million and increased reported expenses from U.S. operations of approximately $11.5 million or a net impact of $4.0 million ($0.038 per share) on an annual basis.

The change in unrealized mark-to-market losses/(gains) on derivative financial instruments resulting from changes in foreign exchange rates relate to contract periods which extend to fiscal 2013. Unrealized mark-to-market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. The following charts provides a summary of the year to date changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Year ended December 30		
	2010	**2009**	**Change**
Foreign Exchange Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (1,424)**	$ (15,682)	**$ 14,258**
Realized loss/(gain) on derivative financial instruments	**(620)**	284	**(904)**
	$ (2,044)	$ (15,398)	**$ 13,354**
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (2,787)**	$ (7,424)	**$ 4,637**
Realized loss on derivative financial instruments	**5,929**	5,504	**425**
	$ 3,142	$ (1,920)	**$ 5,062**
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (2,931)**	$ -	**$ (2,931)**
Realized loss on derivative financial instruments	**2,936**	$ -	**$ 2,936**
	$ 5	$ -	**$ 5**
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (7,142)**	$ (23,106)	**$ 15,964**
Realized loss on derivative financial instruments	**8,245**	5,788	**$ 2,457**
Total loss/(gain) on derivative financial instruments	**$ 1,103**	$ (17,318)	**$ 18,421**

The following chart provides a summary of the quarter over quarter changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Three months ended December 31 2010	2009	Change
Foreign Exchange Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (697)**	$ (1,261)	**$ 564**
Realized gain on derivative financial instruments	**(28)**	(148)	**120**
	$ (725)	$ (1,409)	**$ 684**
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market loss/(gain) on derivative financial instruments	**$ (2,333)**	$ (1,627)	**$ (706)**
Realized loss on derivative financial instruments	**1,294**	1,520	**(226)**
	$ (1,039)	$ (107)	**$ (932)**
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (482)**	$ -	**$ (482)**
Realized loss on derivative financial instruments	**404**	$ -	**404**
	$ (78)	$ -	**$ (78)**
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (3,512)**	$ (2,888)	**$ (624)**
Realized loss on derivative financial instruments	**1,670**	1,372	**298**
Total loss/(gain) on derivative financial instruments	**$ (1,842)**	$ (1,516)	**$ (326)**

APUC previously managed this risk primarily through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. As a result of the current business strategy and lower payout ratio, APUC has determined that the prior practice of hedging 100% of its U.S. currency exposure is no longer appropriate and is taking steps to eliminate its existing forward currency contract program. During the twelve months ended December 31, 2010, APUC terminated forward contracts of $36.8 million. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. For the twelve months ended December 31, 2010, APUC realized cash gains of $0.5 million on managing its forward contracts.

The following chart sets out as at December 31, 2010 the amounts, hedge proceeds and average hedged rates over the term of the foreign exchange forward contracts outstanding. The remaining contracts were terminated subsequent to the end of the quarter:

	Total	2011	2012
Total U.S. $ Hedged	$ 3,000	$ -	$ 3,000
Total Can. $ Proceeds	$ 3,000	-	3,000
Average Hedged Rate	$ 1.000	n/a	$ 1.000
Unrealized Gain (loss)	**$ (45)**	n/a	**(45)**
Impact of a $0.10 move in exchange rates	**$ 300**	n/a	**$ 300**

Based on the fair value of the forward contracts using the exchange rates as at December 31, 2010, the exercise of these forward contracts will result in the use of cash of $45 in fiscal 2012. Assuming a decrease in the strength of the U.S. dollar relative to the Canadian dollar of $0.10 at December 31, 2010, with a corresponding increase in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $0.3 million in fiscal 2012.

Market price risk

The majority of APCo's electricity generating facilities sell their output pursuant to long-term PPAs. However, certain of APCo's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each $10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of $1.0 million on an annualized basis.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables. APUC does not believe this risk to be significant as approximately 72% of APCo Renewable Energy division's revenue, approximately 70% of APCo Thermal Energy division's revenue, and over 56% of total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	20,500	25%
Manitoba Hydro	AA	19,700	24%
Ontario Electricity Financial Corporation	A+	8,400	10%
Maine Public Service		4,600	6%
National Grid	A-	3,100	4%
Public Service Company of New Hampshire	BBB	2,800	3%
Total		**$ 59,100**	**72%**
Thermal Energy Division			
Pacific Gas and Electric Company	BBB+	15,700	25%
Regional Municipality of Peel	AAA	14,500	23%
Ahlstrom	1R3	11,400	18%
Connecticut Light and Power Company	BBB	5,800	9%
Total		**$ 65,700**	**70%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2011

The remaining revenue is primarily earned by Liberty Water. In this regard, the credit risk related to Liberty Water accounts receivable balances of U.S. $5.0 million is spread over approximately 70,000 customers, resulting in an average outstanding balance of approximately $72.00 per customer. Liberty Water has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

Interest rate risk

APCo has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Facility has an outstanding balance drawn of CAD $64.5 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by CAD $0.6 million annually. Algonquin had fixed for floating interest rate swap in an amount of CAD $100.0 million which expired on December 31, 2010. At December 31, 2010, the mark-to-market value of the interest rate swap was nil (2009 – $3.3 million net liability).

- APCo's project debt at the St. Leon facility had a balance of $68.8 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.7 million annually. Although the underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank's prime rate, APCo has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt's interest and principal repayment schedule. This minimizes volatility in the interest expense on this debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. APCo has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2010, the mark-to-market value of the interest rate swap was a net liability of $5.4 million (2009 – net liability of $5.0 million).

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of $0.24 per share per year. On March 3, 2011, the Board approved an annual dividend increase of $0.02 per common share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per common share. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensure APUC's long-term success. Based on the level of dividends paid during the three and twelve months ended December 31, 2010, cash provided by operating activities exceeded dividends declared by 3.2 times and 2.0 times respectively.

As at December 31, 2010, APUC had cash on hand of $5.1 million and $44.4 million available to be drawn on the Facility. The Facility was renewed subsequent to December 31, 2010 and therefore the Facility has been classified on the consolidated balance sheet as a long term liability.

APUC reduced its level of short-term borrowings through the renewal of the Facility on February 14, 2011 for a three year term and through a U.S. $50 million private placement debt financing at Liberty Water on December 22, 2010. In addition, APUC continues to seek to reduce short term borrowings by obtaining appropriate long term debt through refinancing certain project specific financings or additional medium to long term notes. See the Liquidity and Capital Reserves section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facility.

The Facility and project specific debt total approximately $257.4 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $1.0 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $1.2 million or a net increase in operating profits of approximately $0.2 million.

- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk buts has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $1.0 million on an annual basis. However, historically, changes in the price of natural gas are generally matched with changes in market electricity prices which should result in a minimal impact on operating profit.

- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $0.1 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $0.2 million or a net increase in operating profits of approximately $0.1 million.

- APCo's Energy Services Business provides the short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 130,000 MW-hrs in fiscal 2011. While the Tinker Assets are expected to provide the majority of the energy required to service these customers, the Energy Services Business anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that the Energy Services Business was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $1.3 million on an annualized basis.

  This risk is mitigated though the use of short-term financial energy hedge contracts. APCo has committed to acquire approximately 12,000 MW-hrs of net energy over the next 2 months at an average rate of approximately $70 per MW-hr. The mark-to-market value of these forward energy hedge contracts at December 31, 2010 was a net liability of U.S. $0.4 million.

  Subsequent to December 31, 2010, APCo entered into a financial energy hedge contract to acquire approximately 215,000 MW-hrs of energy over a three year period starting March 1, 2011 at an average rate of approximately $50 per MW-hr.

OPERATIONAL RISK MANAGEMENT

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter. A more detailed assessment of APUC's business risks is also set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. Accordingly, dividends to shareholders are dependent upon the profitability of each of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. The water distribution networks of the Liberty Water operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Water) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

Regulatory Risk

Profitability of APUC businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Water's facilities are subject to rate setting by State regulatory agencies. Liberty Water has five ongoing rate cases before regulatory bodies in Arizona and Texas in varying stages of completion. More details regarding the status of these proceedings are set out in Outlook – Liberty Water. The time between the incurrence of costs and the granting of the rates to recover those costs by utility commissions is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Water and wastewater utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Water, and while Liberty Water believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Water regularly works with these authorities to manage the affairs of the business.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its financial statements.

Generally, APCo's hydroelectric facilities are subject to some form of a water use agreement. The terms of these agreements vary by facility as they are agreements made with the local government body that regulates electrical energy generators and can extend over many years. Certain of the agreements contain clauses which allow the regulating body the option to require APCo to decommission the facility upon the expiry or termination of the agreements. Other facilities have no specific obligations other than to maintain the facility in good working order. APCo has options in many of its existing water use agreements to renew or extend the agreements and anticipates being in a position to extend the majority of its agreements and continue to operate its facilities. Based on historical general practice within the regions in which APCo has facilities, APCo has assessed the probability of being required to decommission a facility upon the expiry of a water use agreement to be remote. As such, any potential asset retirement obligation expense has been assessed as insignificant as the obligation would be incurred well into the future and there is a remote likelihood of being required to decommission a facility.

The Renewable Energy division's St. Leon facility does not own the property on which its turbines are located. In 2004, St. Leon entered into long-term right-of-way agreements with land owners which allowed it to construct and maintain the wind turbines used by the facility on their property. These agreements are for minimum terms of 40 years and, upon expiry or termination, provide the land owners with title to the equipment if it is not decommissioned by APCo at its option. While APCo anticipates being in a position to renew or extend the existing PPA in 2025, in the event that APCo is unable to renew or extend the agreement, or identify another purchaser of the energy, APCo may choose to decommission the facility. APCo has assessed there to be a remote likelihood of incurring any cost to decommission the wind farm.

The APCo Thermal Energy division's EFW facility owns the property on which its facility operates. EFW's current waste incineration agreement expires in 2012 with two five year options to extend. While APCo anticipates being in a position to renew or extend the existing contract in 2012, in the event that APCo is unable to renew or extend the agreement, APCo may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

Liberty Water's facilities operate under agreements with a state or municipal regulator to provide the sole water distribution and/or wastewater treatment services in its area of operations, as set out in the agreements. In general, these facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Water has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging wastewater treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus Liberty Water is allowed to earn a return on its investment.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies. APCo has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APCo has not recorded any contingent liabilities on its financial statements.

To manage these risks responsibly, APUC has ensured the Environmental and Compliance departments have been established within the different operating subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required. In the aggregate, the departments comprise 7 full time equivalent positions based out of head office and have an annual budget of approximately $1.0 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

APUC and its subsidiaries have procedures to prevent and minimize any impact of possible oil spills and soil contamination that meet generally accepted industry practices. APCo's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

The APCo Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric facility include possible dam failure which results in upstream or downstream flooding and equipment failure which result in oil or other lubricants being spilled into the waterway. In addition, the operation of a hydroelectric facility may cause the water in the associated waterway to flow faster, or slower, which could result in water flow issues which impact fish population, water quality and potential increases in soil erosion around a dam facility. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility. Federal regulators in the U.S. inspect certain hydroelectric facilities on an annual basis and complete an environmental inspection every 3-5 years.

The primary environmental risks associated with the operation of a wind farm include potential harm to the local and migratory bird population, potential harm to the local bat population as well as concerns over noise levels and visual 'harm' to the scenic environment around the wind farm. As part of the federal and provincial approval of the St. Leon wind project, certain pre-construction and post construction monitoring studies were required. No significant issues were identified as a result of these studies. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility.

The APCo Thermal Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a cogeneration facility include potential air quality and emissions issues, soil contamination resulting from oil spills and issues around the storage and handling of chemicals used in normal operations. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs regular stack testing and tests the calibration of monitoring equipment. The primary environmental risks associated with the operation of an incineration facility include potential air quality, odour and emissions issues, soil contamination resulting from oil or other chemical spills and issues around the storage and handling of municipal solid waste. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

Liberty Water faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a wastewater treatment facility include potential air quality and odour management issues, wastewater spills and surface and ground water contamination. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Water maintains ongoing sampling and testing programs as required in its operational jurisdiction, including annual field investigations by management. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the wastewater collection system and at the wastewater treatment plants that it operates.

The primary environmental risks associated with the operation of a water distribution facility include risk of groundwater contamination by contaminants such as bacterial, synthetic, organic and inorganic pollutants, consumption and availability of groundwater and ensuring water quality continues to meet and exceed Environmental Protection Agency ("EPA") and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Water maintains a regular sampling and testing program as required in its operational jurisdiction. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the water distribution systems that it operates.

Federal drinking water legislation in the United States requires all drinking water systems to meet specific standards. The costs of complying with drinking water standards form part of a facility's rate case applications.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Specific Environmental Risks

Greenhouse Gas Initiatives:

Several north-eastern U.S. States have formed a coordination group to develop a multi-state green house gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative ("RGGI"), has received backing from several states where APCo operates facilities including Connecticut and New Jersey. RGGI drafted a model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program will be implemented to regulate CO2 emissions from large electrical generation facilities, including the Windsor Locks facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks facility is the only APCo site that is currently affected by the RGGI regulations. As such APCo will be required to purchase approximately 250,000 tons of CO2 allowances per year, equivalent to the total annual CO2 emissions from the Windsor Locks facility for the 2009 to 2012 fiscal years. APCo is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. APCo submitted an application on October 31, 2008 for allowances under the available programs. For 2010, APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks facility to be between $0.2 and $0.4 million.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called the Western Climate Initiative ("WCI"). This group recently released details of its Regional Cap-and-Trade Program, which is scheduled to start on January 1, 2012. Each member state/province is now responsible for developing the draft design of the Regional Cap-and-Trade Program and taking the necessary steps to implement the Program within its jurisdiction. APCo owns and operates the Sanger facility in California and the EFW facility in Ontario and holds investments in two others in Ontario which could be impacted by this program. As this process has just begun, it is too early to determine the potential financial impact on APCo and means available to mitigate this financial impact, if any.

The Carbon Disclosure Project ("CDP") is an independent non-profit organization that represents institutional investors managing over $57.0 trillion of assets. The CDP is specifically working to encourage companies worldwide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both potential physical impacts and regulatory changes that may result in an effort to address climate change.

APCo submitted a baseline greenhouse gas emissions inventory to the CDP at the end of June 2008. The emissions data includes both direct emissions from our processes as well as indirect emissions from purchased power. The emissions inventory has been developed based on guidance from the Greenhouse Gas Protocol. This submission will allow comparisons with other firms to be made, and will also be useful as a baseline for addressing climate change regulations.

Renewable Energy Division:

As a result of certain legislation passed in Quebec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. This is discussed in greater detail within the analysis of results in the Renewable Energy Division.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates four hydroelectric facilities in Ontario. While it is too early to assess the costs of compliance, it is possible that modifications to certain dam structures may be required in order to be compliant with any new regulations should they come into effect. Any capital costs associated with the anticipated modifications are expected to be significantly lower than the expected capital costs related to the Quebec facilities, as there are fewer facilities in Ontario and they are of newer construction.

Liberty Water:

Liberty Water owns and operates the LPSCo facility, a water distribution and waste-water treatment utility servicing the City of Litchfield Park, and parts of the City of Goodyear, the City of Avondale and the County of Maricopa, Arizona, where groundwater pollutants, namely trichloroethylene ("TCE") originally employed by a former aerospace manufacturing plant in the nearby City of Goodyear are progressing toward three of the twelve wells that provide water to the LPSCo service area. The EPA began monitoring TCE in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA regular technical meetings in regards to this monitoring program, LPSCo closely monitors its wells for this groundwater pollutant through the sampling and testing of water from wells that are potentially at risk of contamination. To date there have not been any detectable levels of TCE in the water from wells used by LPSCo. EPA's monitoring and control efforts have not indicated that the concentrations are being reduced or fully captured. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are underway. In the event that any wells exceed EPA permitted TCE level, LPSCo would undertake the appropriate actions which may include installing appropriate treatment facilities or removing the well from the water distribution system of the utility. In the event of removal of a well, there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of

LPCSo's customers. In addition, LPSCo has identified alternate sites where replacement wells can be established to replace this lost capacity. The cost of establishing a new well is estimated to be between $2.0 million and $3.5 million depending on the location, depth and other factors. The cost of commissioning a well forms part of the rate base for the utility. Other factors that can impact the cost of a well include, but are not limited to, any requirement to construct wellhead treatment for pollutants, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Water does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2010.

Seasonal fluctuations and hydrology

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized. For Liberty Water's water utilities, demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Wind resource

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

As reported in previous public filings of Algonquin and as discussed above under *"Related Party Transactions"*, APUC and an affiliate of APMI are involved in civil proceedings and bankruptcy proceedings with Trafalgar, Algonquin acquired notes secured by, among other things, seven hydroelectric facilities owned by Traflagar. In 1997, Algonquin moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar had previously won a $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. Trafalgar commenced an action in 1999 in U.S. District Court against Algonquin, APMI and various other entities related to them in connection with, among other things, the sale of the one of the notes by Aetna Life Insurance Company to the Fund and in connection with the foreclosure on the security for the note. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the note, that Algonquin was therefore the holder and owner of the note, and that all other claims by Trafalgar with respect to the transfer of the note were without merit. In 2008 Algonquin filed for summary judgement seeking dismissal of Trafalgar's remaining claims, and the District Court granted this motion on November 6, 2008. On October 22, 2009 Trafalgar filed an appeal from the November 6, 2008 summary judgement to the United States Court of Appeals for the Second Circuit. The Second Circuit Court of Appeals on November 1, 2010 dismissed all the claims against APCo in the civil proceedings. The bankruptcy proceedings are continuing.

On December 19, 1996, the Attorney General of Québec ("Québec AG") filed suit in Québec Superior Court against Algonquin Développement Côte Ste-Catherine Inc. (Développement Hydromega), a predecessor company to an APUC subsidiary. The Québec AG at trial claimed $5.4 million for amounts that the APUC entities have been paying to the federal authority under its water lease with the authority. The APUC entities brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009 and the appeal was heard by the Court of Appeal January 31, 2011. The Côte Ste-Catherine Facility currently pays water lease dues to the federal government, but if the Québec AG is successful in final appeal, an adjustment and/or increase of such amounts is possible.

Obligations to serve

Liberty Water's utility facilities may be located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Water may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Tax risks associated with the Unit Exchange Offer

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of Hydrogenics or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange Offer for APUC. While APUC is confident in its position, such a challenge or legislation could potentially and materially affect the availability or amount of the tax attributes or other tax accounts of APUC.

Disclosure Controls

At the end of the fiscal year ended December 31, 2010, APUC carried out an evaluation, under the supervision of and with the participation of the APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of the Company's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2010, APUC's disclosure controls and procedures were adequately designed and effective in ensuring that: (i) information required to be disclosed by APUC in reports that it files or submits to the Securities and Exchange Commission under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in applicable rules and forms and (ii) material information required to be disclosed in its reports filed under the Exchange Act is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow for accurate and timely decisions regarding required disclosure.

Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the

risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2010 based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2010.

During the year ended December 31, 2010, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2010.

Millions of dollars (except per share amounts)	1st Quarter 2010	2nd Quarter 2010	3rd Quarter 2010	4th Quarter 2010
Revenue	$ 45.9	$ 42.7	$ 45.4	$48.9
Net earnings /(loss)	3.5	(2.2)	1.5	16.9
Net earnings / (loss) per share	0.04	(0.02)	0.02	0.18
Total Assets	966.2	983.2	969.4	980.9
Long term debt*	434.0	446.7	452.8	461.0
Dividend/distribution per share	0.06	0.06	0.06	0.06
	1st Quarter 2009	2nd Quarter 2009	3rd Quarter 2009	4th Quarter 2009
Revenue	$ 52.2	$ 46.5	$ 45.1	$43.4
Net earnings / (loss)	4.2	15.3	13.1	(1.4)
Net earnings / (loss) per trust unit	0.05	0.20	0.17	(0.03)
Total Assets	974.2	952.4	925.7	1,013.4
Long term debt*	457.6	456.2	445.4	439.9
Distribution per trust unit	0.06	0.06	0.06	0.06

* Long term debt includes long term liabilities, the Facility, convertible debentures and other long term obligations

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $42.7 million and $52.2 million over the prior two year period. A number of factors impact quarterly results including seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the significant fluctuation in the strength of the Canadian dollar which has resulted in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of $16.9 million and a net loss of $2.2 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax expense due to the enactment of Bill C-52 and mark-to-market gains and losses on financial instruments.

Critical Accounting Estimates

APUC prepared its Consolidated Financial Statements in accordance with Canadian GAAP. An understanding of APUC's accounting policies is necessary for a complete analysis of results, financial position, liquidity and trends. Refer to Note 1 to the Consolidated Financial Statements for additional information on accounting principles. The Consolidated Financial Statements are presented in Canadian dollars rounded to the nearest thousand, except per unit amounts and except where otherwise noted.

Additional disclosure of APUC's critical accounting estimates is also available in APUC's MD&A for the year ended December 31, 2009 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Changes in Accounting Policies

APUC's accounting policies are described in Note 1 to the Consolidated Financial Statements for the period ended December 31, 2010. There have been no changes to the critical accounting policies as disclosed in APUC's audited Consolidated Financial Statements for the year ended December 31, 2009 except as disclosed below.

Change in accounting estimates

As a result of the change in its corporate structure, APUC re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the U.S. divisions operate. APUC concluded that the U.S. operations of the Renewable Energy and Thermal Energy divisions no longer should be classified as integrated foreign operations but rather self-sustaining operations. Consequently, these divisions are prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37.6 million resulting from the current rate translation of non-monetary items principally property, plant and equipment and intangible assets as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

Accounting Framework

In 2011, most publicly accountable enterprises in Canada will be required to change the accounting framework under which financial statements are prepared to International Financial Reporting Standards ("IFRS"). The adoption of IFRS is one of the alternatives available to APUC. As an entity with rate-regulated activities, APUC could also avail itself of the one-year deferral approved by the Accounting Standard Board of the Canadian Institute of Chartered Accountants in September 2010. Alternatively, as an existing SEC registrant, APUC could also choose to report its financial statements under U.S. GAAP.

APUC evaluated the three options and assessed which of the three accounting frameworks would provide its shareholders and other interested readers of its financial statements the most useful basis for financial reporting. Considering the short-term nature of the CICA solution and the uncertainty around the eventual adoption of a rate-regulated accounting standard under IFRS, U.S. GAAP financial statements represent the least disruptive accounting framework for readers of APUC's financial statements. This option would result in minimal changes having to be made to its financial statements as there are fewer differences between U.S. GAAP and current Canadian GAAP. U.S. GAAP also includes accounting standards for rate-regulated activities within the financial statements.

As such, APUC has decided to adopt U.S. GAAP effective January 1, 2011 for purposes of Canadian and U.S. reporting requirements. U.S. GAAP reporting is permitted by Canadian securities laws and the TSX for companies subject to reporting obligations under U.S. securities laws.

Changeover to U.S. Generally Accepted Accounting Standards –January 1, 2011

Reconciliation to U.S. GAAP

Canadian GAAP differs in certain material respects from U.S. GAAP. The reconciliation to U.S. GAAP in note 24 of the consolidated financial statements provides a reconciliation to U.S. GAAP of net earnings, balance sheet and deficit for the years ended December 31, 2010 and 2009.

Significant Changes in Accounting Policies upon Conversion
Commencing in the first quarter of 2011, U.S. GAAP will be applied retrospectively to all prior periods. We expect to make changes in our accounting policies to be compliant with U.S. GAAP. Our U.S. GAAP policies are expected to be consistent with the policies we applied in preparing the reconciliation reflected below. As such, the descriptions contained within the reconciliation are anticipated to be reflective of the changes we plan to make in our adoption of U.S. GAAP.

Impact on the organization
As an SEC registrant, APUC reconciles its financial statements from Canadian GAAP to U.S. GAAP for purpose of annual reporting on Form 40-F with the SEC as a foreign private issuer. As a consequence, no significant impact of the transition to U.S. GAAP is expected on APUC's internal controls, information technology systems and financial reporting expertise requirements. No financial covenants are expected to be impacted by APUC's conversion to U.S. GAAP given the few differences that exist with Canadian GAAP.

MANAGEMENT'S REPORT

Financial Reporting
The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles and reconciled to US GAAP. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2010.

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, the consolidated statements of operations, deficit, comprehensive income (loss) and accumulated other comprehensive income (loss), and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

KPMG

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2010 and 2009 and the consolidated results of its operations and its consolidated cash flows for the two years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 3, 2011

Algonquin Power & Utilities Corp

Consolidated Balance Sheets

(thousands of Canadian dollars)

	2010	2009
ASSETS		
Current assets:		
Cash	$ 5,146	$ 2,796
Short term investments (note 1(d))	3,674	40,010
Accounts receivable	27,082	20,484
Prepaid expenses	3,520	4,674
Income tax receivable	-	1,143
Current portion of future tax asset (note 13)	14,015	14,566
Current portion of notes receivable (note 5)	1,172	414
	54,609	84,087
Long-term investments and notes receivable (note 5)	35,902	23,470
Future non-current income tax asset (note 13)	74,006	61,219
Property, plant and equipment (note 6)	729,076	749,350
Intangible assets (note 7)	73,886	85,929
Restricted cash (note 1(e))	3,563	4,316
Deferred financing costs	258	200
Other assets (note 8)	9,617	4,842
	$ 980,917	$ 1,013,413
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 33,506	$ 33,219
Dividends payable	5,721	1,857
Current portion of long-term liabilities (note 9)	70,490	3,360
Current portion of other long-term liabilities (note 11)	1,011	1,025
Current portion of derivative instruments (note 22)	2,338	5,775
Current income tax liability	200	5
Current portion of deferred credit (note 13)	11,020	10,500
Future income tax liability (note 13)	514	913
	124,800	56,654
Long-term liabilities (note 9)	188,641	241,412
Convertible debentures (note 10)	170,975	173,257
Other long-term liabilities (note 11)	30,872	25,228
Future non-current income tax liability (note 13)	80,953	79,914
Derivative instruments (note 22)	3,525	3,920
Deferred credit (note 13)	32,222	39,379
Shareholders' equity:		
Shareholders' capital (notes 3 and 12)	796,576	787,037
Deficit	(347,802)	(344,676)
Accumulated other comprehensive loss	(99,845)	(48,712)
	348,929	393,649
Commitments and contigencies (note 15)		
Subsequent events (notes 4(a) and 9)		
	$ 980,917	$ 1,013,413

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp

Consolidated Statements of Operations

(thousands of Canadian dollars, except per unit amounts)

	2010	2009
Revenue:		
Energy sales	$ 132,726	$ 130,436
Waste disposal fees	9,039	14,468
Water reclamation and distribution	37,786	38,513
Other revenue (note 20)	3,331	3,848
	182,882	187,265
Expenses		
Operating	97,851	102,736
Amortization of property, plant and equipment	36,429	38,578
Amortization of intangible assets	10,144	7,305
Management costs (note 14)	-	850
Administrative expenses	14,886	10,712
Gain on foreign exchange	(528)	(1,261)
	158,782	158,920
Earnings before undernoted	24,100	28,345
Interest expense	25,612	21,387
Interest, dividend and other income (note 19)	(4,962)	(6,401)
Impairment loss of property, plant and equipment (note 6)	2,492	5,354
Write down of note receivable (note 5)	-	1,103
(Gain) / loss on derivative financial instruments (note 22)	1,103	(17,318)
	24,245	4,125
Earnings/(loss) from operations before income taxes, non-controlling interest and corporatization costs	(145)	24,220
Management internalization costs (note 14)	-	4,693
Other corporatization costs (note 3)	-	3,460
Earnings/(loss) before income taxes and non-controlling interest	(145)	16,067
Income tax expense (recovery) (note 13)		
Current	(69)	397
Future	(20,159)	(18,324)
	(20,228)	(17,927)
Non-controlling interest in earnings of subsidaries	444	2,737
Net earnings	$ 19,639	$ 31,257
Basic net earnings per share (note 18)	$ 0.21	$ 0.39
Diluted net earnings per share (note 18)	$ 0.21	$ 0.39

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp

Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

	2010	2009
Cash provided by (used in):		
Operating Activities:		
Net earnings	$ 19,639	$ 31,257
Items not affecting cash:		
Amortization of property, plant and equipment	36,429	38,578
Amortization of intangible assets	10,144	7,305
Other amortization	2,911	1,441
Future income taxes / (recovery)	(20,159)	(18,324)
Gain on sale of land	-	(1,451)
Stock option expense	108	-
Write down of property, plant and equipment	2,492	5,354
Write down of note receivable	-	1,103
Expense on convertible debenture conversion	-	1,252
Management internalization costs	-	4,693
Unrealized gain on derivative financial instruments	(7,142)	(23,106)
Minority interest	444	2,737
Unrealized foreign exchange gain	(414)	(1,503)
	44,452	49,336
Changes in non-cash operating working capital (note 17)	728	(1,305)
	45,180	48,031
Financing Activities:		
Cash distributions / dividends (note 16)	(18,901)	(19,043)
Cash distributions to non-controlling interest (notes 14 and 16)	(444)	(809)
Common share issue, net of costs	-	21,180
Convertible debenture issue, net of costs	-	57,975
Repayment Trustee loans	-	218
Deferred financing costs	(1,194)	(109)
Increase in long-term liabilities	98,787	23,000
Decrease in long-term liabilities	(80,078)	(69,175)
Increase / (decrease) in other long-term liabilities	4,456	(5,870)
	2,626	7,367
Investing Activities:		
Decrease in restricted cash	575	343
Decrease / (increase) in short-term investments	36,212	(39,995)
Increase in other assets	(2,723)	(1,597)
Distributions received in excess of equity income	1,140	1,991
Receipt of principal on notes receivable	410	448
Proceeds from liquidation of Highground assets (note 4(f))	170	983
Proceeds from sale of land	-	2,502
Acquisition of long-term investments (notes 4(e) and 5)	(14,759)	(87)
Net additions to property, plant and equipment	(20,831)	(10,916)
The unit exchange transaction (note 3)	-	(10,813)
Acquisitions of operating entities	(45,524)	(1,177)
	(45,330)	(58,318)
Effect of exchange rate differences on cash	(126)	(186)
Increase / (decrease) in cash	2,350	(3,106)
Cash, beginning of the year	2,796	5,902
Cash, end of the year	$ 5,146	$ 2,796
	-	-
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 21,562	$ 19,956
Cash paid / (received) during the period for income taxes	$ (285)	$ 873

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp

Consolidated Statements of Deficit

(thousands of Canadian dollars)

	2010	2009
Balance, beginning of year	$ (344,676)	$ (356,621)
Net earnings	19,639	31,257
Distributions / dividends	(22,765)	(19,312)
Balance, end of year	$ (347,802)	$ (344,676)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp

Consolidated Statements of Comprehensive Income / (Loss) and Accumulated Other Comprehensive Income / (Loss)

(thousands of Canadian dollars)

		2010		2009
Net earnings	$	19,639	$	31,257
Other comprehensive income /(loss):				
Forward exchange contracts settled in the year		-		(1,789)
Translation of self sustaining foreign operations due to accounting change (note 1(n))		(37,605)		-
Translation of self sustaining foreign operations (note 1(n))		(13,528)		(25,481)
Other comprehensive income / (loss)		(51,133)		(27,270)
Total comprehensive income / (loss)	$	(31,494)	$	3,987
Accumulated other comprehensive loss:				
Balance, beginning of the year	$	(48,712)	$	(21,442)
Translation of self sustaining foreign operations due to accounting change (note 1(n))		(37,605)		-
Other comprehensive income / (loss)		(13,528)		(27,270)
Balance, end of the year	$	(99,845)	$	(48,712)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water and energy utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements.

On October 27, 2009, Algonquin Power Income Fund (the "Fund") completed a reverse take-over transaction (the "Transaction") of Hydrogenics Corporation ("Hydrogenics") which resulted in the Fund's unitholders becoming shareholders in Hydrogenics which was immediately renamed Algonquin Power & Utilities Corp. As a result, the Fund itself became a wholly owned subsidiary of APUC. The transaction did not result in any change to the underlying business operations of the Fund. For accounting purposes APUC is considered a continuation of the Fund, and as such, these consolidated financial statements follow the continuity of interest method of accounting. The Transaction and its accounting treatment are more fully described in note 3.

Up to December 21, 2009, the Fund was managed by Algonquin Power Management Inc. ("APMI") (see note 14).

On March 4, 2010 the Trustees approved a resolution changing the name of the Fund from Algonquin Power Income Fund to Algonquin Power Co. ("APCo")

APUC's power generation business unit conducts business under the name APCo. APCo owns or has interests in 45 renewable energy facilities and 12 thermal energy facilities representing more than 450 MW of installed electrical generation capacity. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co ("Liberty Utilities"). Liberty Water, a wholly owned subsidiary of Liberty Utilities, owns 19 utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois. The regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The utilities use a historic test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

1. Significant accounting policies:

(a) Basis of consolidation:

The accompanying audited consolidated financial statements of APUC have been prepared according to Canadian generally accepted accounting principles ("GAAP"), applied on a consistent basis, and includes the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIE") where the Company is the primary beneficiary. Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE, as the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company.

Intercompany transactions and balances have been eliminated.

(b) Accounting for rate regulated operations:

Effective October 1, 2009, APUC retrospectively adopted rate regulated accounting for Canadian GAAP reporting in its Liberty Water utilities following the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under Canadian GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Items to which regulatory accounting requirements apply include deferred rate case costs, and capitalization of allowance for equity funds used during construction of regulated capital projects.

Deferred rate case costs relate to costs incurred by APUC's utilities to file, prosecute and defend rate case applications and which the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator while they are expensed under Canadian GAAP for non-regulated entities.

Under ASC 980, allowance for funds used during construction projects included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. It represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction). Prior to the adoption of ASC 980, APUC capitalized interest costs directly attributable to the construction of these assets but did not capitalize the allowance for equity funds used during construction projects.

(c) Cash:

Cash consists of cash deposited at banks.

1. Significant accounting policies: (continued)

(d) Short term investments:

Short term investments, consist of money market instruments with maturities in January 2011 and are recorded at cost, which approximates current market value. Included in short term investments is an investment of $3,694 (2009 - $10,000) which is denominated in US dollars.

(e) Restricted cash:

Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(f) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. Amounts collected on trade accounts receivable are included in net cash provided by operating activities in the Consolidated Statements of Cash Flows. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the current receivables aging and current payment patterns. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(g) Property, plant and equipment:

Property, plant and equipment, consisting of land, facilities and equipment, are recorded at cost. The costs of acquiring or constructing facilities together with the related interest costs during the period of construction are capitalized. Interest costs capitalized for Liberty Water's utilities also include the allowance for equity funds used during construction.

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

The facilities and equipment, which include the cost of major overhauls, are amortized on a straight-line basis over their estimated useful lives. For facilities these periods range from 15 to 40 years. Facility equipment and overhaul costs are amortized over 2 to 10 years.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Water's utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment would be charged to net earnings as incurred.

1. Significant accounting policies: (continued)

(h) Intangible assets:

Power sales contracts and energy sales contracts acquired are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition for power sales contracts and 12 months for energy sales contracts.

Customer relationships are amortized on a straight-line basis over 40 years.

(i) Deferred costs:

Deferred costs consist of costs of arranging APCo's credit facility.

(j) Impairment of long-lived assets:

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. Recoverability is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

(k) Long-term investments and notes receivable:

Investments in which APUC has significant influence but not control or joint control are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the Consolidated Statement of Operations. All other equity investments where APUC does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and are adjusted only for other-than-temporary declines in value and additional investments.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are recorded at face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity. The interest income on notes receivable is included in net cash provided by operating activities in the Consolidated Statements of Cash Flows.

The allowance for doubtful accounts is the Company's best estimate of the amount of credit losses in the Company's existing notes. The allowance is determined on an individual note basis if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate. The Company does not accrue interest when a note is considered impaired. When ultimate collectability of the principal balance of the impaired note is in doubt, all cash receipts on impaired notes are applied to reduce the principal amount of such notes until the principal has been recovered and are recognized as interest income thereafter. Impairment losses are charged against the allowance and increases in the allowance are charged to bad debt expense. Notes are written off against the allowance when all possible means of collection have been exhausted and the potential for recovery is considered remote.

1. Significant accounting policies: (continued)

(l) Other long-term liabilities:

Other long-term liabilities include advances in aid of construction. Certain of APUC's water and wastewater utilities are provided with advances through contributions from customers, real estate developers and builders for water and sewage main extensions in order to extend water and sewer service to their properties. The amounts advanced are generally repayable over a prescribed period based on revenues generated by the housing or development in the area being developed as new customers are connected to and take service from the utilities. Generally, advances not refunded within the prescribed period are not required to be repaid. The estimated portion of the advance that will not be refunded amounts to $33,848 and is credited to property, plant and equipment as a contribution in aid of construction. APUC also receives contributions in aid of construction with no repayment requirements in which case the full amount is immediately treated as a capital grant and netted against property, plant and equipment. The estimated amount of contributions that are expected to be ultimately refunded is recorded as Advances in Aid of Construction in other long-term liabilities.

Other long-term liabilities also include deferred water rights. Deferred water rights result from a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Water's utilities' obligation by its respective state regulator to collect a deposit from each customer of its facilities when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

(m) Recognition of revenue:

Revenue derived from energy sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Water reclamation and distribution revenues are recorded when processed or delivered to customers.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts are recognized based on actual tonnage at the expected price for the contract year.

Interest from long-term investments is recorded as earned.

1. Significant accounting policies: (continued)

(n) Foreign currency translation:

APUC's policy for translation of foreign operations depends on whether the foreign operations are considered integrated or self-sustaining. In 2009, APUC's foreign operations, other than Liberty Water, were considered integrated and translated into Canadian dollars using the temporal method whereby current rates of exchange are used for monetary assets and liabilities, historical rates of exchange for non-monetary assets and liabilities and average rates of exchange for revenues and expenses, except amortization which was translated at the rates of exchange applicable to the related assets. Gains and losses resulting from these translation adjustments were included in income.

As a result of the change relating to conversion of the Company from an income trust to a corporate structure at the end of 2009, the Company re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the US divisions operate. The Company concluded that the US operations of the Renewable Energy and Thermal Energy divisions no longer should be classified as integrated foreign operations but rather as self-sustaining operations. Consequently, these divisions have been prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37,605 resulting from the current rate translation of non-monetary items, principally property, plant and equipment and intangible assets, as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

Liberty Water's utilities are considered self-sustaining foreign operations since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. These self-sustaining operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income in the Consolidated Statement of Comprehensive Income.

(o) Asset retirement obligations:

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations. Actual expenditures incurred are charged against the accumulated obligation. Based on APUC's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations have been recorded in 2010 and 2009.

1. Significant accounting policies: (continued)

(p) Income taxes:

Income taxes are accounted for using the asset and liability method. Future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the year that includes the date of enactment or substantive enactment.

The structure of APUC and its subsidiaries are complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there are can be tax matters that have uncertain tax positions. The Company recognizes income tax benefits of uncertain tax filing positions when it is more likely than not that the ultimate determination of the tax treatment of the position will result in that benefit being realized. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

A valuation allowance is recorded against future tax assets to the extent that it is considered more likely than not that the future tax asset will not be realized.

(q) Financial instruments and derivatives:

APUC has classified its cash, short term investments, accounts receivable, restricted cash, accounts payable and accrued liabilities and dividends payable as held-for-trading, which are measured at fair value. Notes receivable are classified as loans and receivables, which are measured at amortized cost as there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are classified as other financial liabilities, which are measured at amortized cost, using the effective interest method.

Transaction costs that are directly attributable to the acquisition or issuance of financial assets or liabilities are accounted for as part of the respective asset or liability's carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Costs considered as commitment fees paid to financial institutions are recorded in deferred costs, and amortized on a straight-line basis over the term of the debt facility.

1. Significant accounting policies: (continued)

Financial instruments and derivatives (continued):

Unrealized holding gains and losses on trading securities are included in earnings. A decline in the market value of any held-to-maturity security below cost that is deemed to be other-than-temporary results in an impairment to reduce the carrying amount to fair value. To determine whether an impairment is other-than-temporary, the Company considers all available information relevant to the collectability of the security, including past events, current conditions, and reasonable and supportable forecasts when developing estimate of cash flows expected to be collected. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year end, forecasted performance of the investee, and the general market condition in the geographic area or industry the investee operates in.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values and the change in fair value is included in the Consolidated Statements of Operations. None of the derivatives were designated in hedging relationships for accounting purposes.

(r) Fair Value Measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(s) Stock Option Plan

The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity-classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value using the Black-Scholes option-pricing model.

1. Significant accounting policies: (continued)

(t) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of future tax assets, the portion of advances in aid of construction payments that will not be repaid, assessments of asset retirement obligations, and the fair value of financial instruments, derivatives and stock options. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements not yet adopted and accounting framework

(a) CICA Section 1582 – Business Combinations

In January 2009, the CICA issued Handbook Section 1582, Business combinations, which replaces the existing standards. This section establishes the standards for the accounting of business combinations, and states that all assets and liabilities of an acquired business will be recorded at fair value. Estimated obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and that restructuring charges will be expensed in the periods after the acquisition date. This standard is applied prospectively to business combinations with acquisition dates on or after January 1, 2011. Earlier adoption is permitted. The Company did not early adopt this new standard.

(b) Accounting framework

As an SEC registrant, APUC has elected to report its financial statements under US GAAP commencing with the first quarter of 2011. The change in accounting framework will be applied retrospectively to all prior periods and appropriate changes to accounting policies will be made in order to comply with US GAAP. Those US GAAP policies are expected to be consistent with the policies applied in preparing the reconciliation reflected in note 24 of these consolidated financial statements.

3. Unit for share exchange (the "Unit Exchange Offer")

In order to effect a change in business structure from an income trust to a corporation, on October 27, 2009, APCo's unitholders exchanged 100% of the outstanding trust units of APCo for a new class of common shares ("New Common Shares") of APUC (formerly Hydrogenics Corporation or Hydrogenics), on a one for one basis. Immediately prior to this exchange, under a Plan of Arrangement, Hydrogenics transferred all of its operations and substantially all its assets and liabilities to a newly created company ("New Hydrogenics"). The pre-existing publicly traded shares of Hydrogenics were contemporaneously redeemed for shares of New Hydrogenics and thus the pre-existing publicly traded shares of Hydrogenics no longer exist. As a result of the Unit Exchange Offer, APUC paid New Hydrogenics $11,307. The transaction resulted in the Unitholders of APCo indirectly holding their interest in APCo as shareholders of APUC. Excluding shares issued under the CD Exchange Offer (as defined and described below), the number of common shares of APUC outstanding immediately after completion of the Unit Exchange Offer was exactly the same as the number of APCo's trust units outstanding immediately before the Unit Exchange Offer.

Accounting treatment of the Unit Exchange Offer

The Unit Exchange Offer is required to be accounted for as a change in business form using the continuity of interests method of accounting in accordance with Emerging Issues Committee abstract 170, "Conversion of an Unincorporated Entity to an Incorporated Entity". Under the continuity of interests method of accounting, the transfer of the assets, liabilities and equity of APCo to APUC were recorded at their net book values as at the effective date of the Transaction. As a result, for accounting purposes, APUC is required to be accounted for as though it were a continuation of APCo but with its capital reflecting the exchange of APUC Shares for Trust Units and therefore certain terms such as shareholder/unitholder, dividend/distribution and share/unit may be used interchangeably throughout these consolidated financial statements. For the periods reported up to the effective date of the Unit Exchange Offer, all payments to unitholders were in the form of trust unit distributions, and after that date all payments to shareholders are in the form of dividends.

Comparative figures presented in the consolidated financial statements of APUC include all amounts previously reported by APCo. In addition, a future tax asset of $66,954 related to the tax attributes of Hydrogenics Corporation was recognized on the transaction date. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration paid to New Hydrogenics was reflected as a deferred credit of $55,647 on the transaction date to be recognized in income as an income tax expense recovery as the future income tax assets are utilized. As a result of the corporatization transaction, APUC also recorded an increase to future tax liabilities. This adjustment reflects the tax impact of recording future tax assets and liabilities for temporary differences that are reversing or settling prior to 2011 which were previously not recorded since prior to the transactions these temporary difference reversals were not previously expected to be taxed in APCo.

APUC expensed corporatization costs of $3,460 during 2009 in relation to the Unit Exchange Offer.

Contemporaneously with the Unit Exchange Offer a convertible debenture exchange offer ("the CD Exchange Offer) was made by APUC to debentureholders of APCo. The CD Exchange Offer is more fully described in note 10.

4. Acquisitions

(a) Acquisition of electrical generation and regulated distribution utility

In 2009, APUC entered into an agreement to acquire an electrical generation and regulated distribution utility in a partnership with Emera Inc. ("Emera"). APUC will own 50.001% and Emera will own 49.999% of shares of the newly formed California Pacific Utility Ventures LLC, which has agreed to acquire through its wholly owned subsidiary California Pacific Electric Company ("Calpeco") a California-based electricity distribution utility and related generation assets (the "California Utility"). The California Utility provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region.

In connection with the acquisition, on April 23, 2009 Emera also agreed to a conditional treasury subscription for approximately 8.5 million shares of APUC at a price of $3.25 per share. The proceeds of the subscription receipts are intended to fund a portion of the cost of acquisition of the California Utility.

As of December 31, 2010, APUC has incurred costs of $2,210 (2009 - $1,084) related to the acquisition of the California Utility. These costs are recorded as deferred transaction costs and are included in other assets on the Consolidated Balance Sheet.

As of December 31, 2010, APUC has incurred costs of $965 related to the transition of the California Utility. These costs are recorded as other capital assets and are included in other assets on the Consolidated Balance Sheet.

As of December 31, 2010, APUC has incurred costs of $871 related to the financing of the California Utility. These costs are recorded in other assets on the Consolidated Balance Sheet.

The acquisition of the California Utility by Calpeco closed subsequent to year end on January 1, 2011 for a purchase price of approximately US $131,790, subject to certain working capital and other closing adjustments. Delivery of the shares under the subscription receipts occurred simultaneously with the closing of the acquisition.

(b) Agreement to Acquire Electric and Gas Utilities

On December 9, 2010 APUC announced that Liberty Energy Utilities Co. ("Liberty Energy"), APUC's utility subsidiary, had entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company, a regulated electric utility, and EnergyNorth Natural Gas Inc. a regulated natural gas utility from National Grid USA ("National Grid") for total consideration of US $285,000.

The transaction is subject to U.S. state and federal regulatory approval and is expected to close in the fall of 2011. As of December 31, 2010, APUC has incurred costs of $1,889 (2009 - $nil) related to the acquisition. These costs are recorded as deferred transaction costs and are included in other assets on the Consolidated Balance Sheet.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share. The issuance of these subscription receipts is subject to regulatory approval.

(in thousands of Canadian dollars except as noted and amounts per share)

4. Acquisitions (continued)

(c) Acquisition of Hydroelectric Generation Assets ("Tinker Acquisition")

On January 12, 2010, APUC acquired certain electrical generating facility assets located in New Brunswick and Maine. The acquisition consisted of three hydroelectric generating stations, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick. The acquisition also included five thermal generating stations and certain regulated New Brunswick Independent System Operator transmission lines located in proximity to the generating facilities. In connection with the Tinker Acquisition, on February 4, 2010, APUC also acquired a related energy services business ("Energy Services Business").The Energy Services Business retails the electricity generated by the Tinker facilities to commercial and industrial customers in northern Maine.

The total purchase price, including acquisition costs, was $40,671. Acquisition costs of $390 were paid in 2009 which were recorded as deferred transaction costs and included in other assets on the consolidated balance sheet at December 31, 2009 and included in acquisition costs in 2010.

The acquisition has been accounted for using the purchase method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been preliminarily allocated to net assets acquired as follows:

Working capital (net of cash received of $1)	$ 69
Property, plant and equipment	40,817
Intangible asset – energy sales contracts	4,421
Non-current future income tax liability	(1,262)
Derivative liability – energy forward purchase contracts (note 22)	(3,374)
Total cash consideration	$ 40,671

The allocation of the purchase price has been based upon the fair values of the assets and liabilities as of the date of acquisition.

(in thousands of Canadian dollars except as noted and amounts per share)

4. Acquisitions (continued)

(d) Acquisition of Water Utility System ("the Galveston Utility")

On March 17, 2010 Liberty Water, a wholly owned subsidiary of APUC, acquired water distribution and wastewater collection system located near Galveston, Texas for a total purchase price of $2,038. The Galveston Utility provides water distribution and wastewater collection services to approximately 260 equivalent residential connections.

The acquisition has been accounted for using the purchase method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been allocated to net assets acquired as follows:

Property, plant and equipment	$	2,023
Intangible asset		15
Total cash consideration	$	2,038

(e) Acquisition of Entrada Del Oro Sewer Company

In 2008, the Company entered into an agreement to acquire the shares of Entrada Del Oro Sewer Company located in Arizona, for $707 (US$670).

In accordance with the purchase and sale agreement, APUC is required to make additional payments to the previous owners for each additional customer connected to the utility. These payments continue until 2018. As of December 31, 2010, APUC has paid $83 (U.S. $80) (2009 - $87 (U.S. $78)) as a growth premium, and increased long term investments and notes receivable by a similar amount.

(in thousands of Canadian dollars except as noted and amounts per share)

4. Acquisitions (continued)

(f) Highground Capital Corporation

In 2008, the Company entered into an agreement with Highground Capital Corporation ("Highground"), CJIG Management Inc. ("CJIG"), which is the manager of Highground and a related party of the Company controlled by the shareholders of Algonquin Power Management Inc ("APMI") who are current or former executives of the Company. Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and the Company issued trust units to the Highground shareholders and CJIG.

The Company initially recorded the trust units issued at their fair value of $7.69 per unit which, net of transaction costs of $767, resulted in proceeds of the trust units being initially recorded at a value of $26,203. By December 31, 2010, the Company has received consideration and issued equity as follows:

Consideration received:	
Cash and assets received prior to December 31 2008	$26,203
Cash received in 2009	983
Cash received in 2010	170
	$27,356

In 2009, APUC's consideration received from the acquisition exceeded $26,970, the minimum contemplated under the agreements, and, as a result APUC is entitled to 50% of any additional proceeds from the assets formerly owned by Highground. CJIG is entitled to the remaining 50% of any proceeds in excess of the minimum amount. During 2010, APUC received $170 (2009 - $983) from CJIG as APUC's share of the 50% of additional proceeds from the further liquidation of the assets held by Highground. This has been recorded as an increased amount assigned to the equity originally issued.

The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having an approximate principal amount of $2,227. APUC's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded as additional proceeds when received from CJIG.

(in thousands of Canadian dollars except as noted and amounts per share)

5. Long-term investments and notes receivable

Long-term investments and notes receivable consist of the following:

	2010	2009
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 8,197	$ 8,344
25% of Class B non-voting shares of Cochrane Power Corporation	5,775	6,544
45% partnership interest in the Algonquin Power (Rattle Brook) Partnership	3,790	3,827
Investment in Entrada Del Oro (note 4 (e))	568	709
Red Lily Subordinated loan, interest at 12.5% (note 5 (a))	6,565	
Red Lily Senior loan, interest at 6.31% (note 5 (a))	6,100	-
Chapais Énergie, Société en Commandite 12.1% interest in Tranche A and Tranche B term loans The loans bear interest at the rate of 10.789% and 4.91%, respectively	3,329	3,701
Silverleaf resorts loan, interest at 15.48% (note 5 (b))	2,010	-
Note Receivable - Twin Falls. The note bears interest at the rate of 6.75%	740	759
	37,074	23,884
Less: current portion	(1,172)	(414)
Total long term investments and notes receivable	$ 35,902	$ 23,470

The above notes are secured by the underlying assets of the respective facilities. There is no allowance for doubtful account in regards to the notes receivable as at December 31, 2010 and 2009.

(a) Red Lily I

On April 19, 2010, the Company entered into agreements to provide development, construction, operation and supervision services related to the construction, commissioning and operation of a 26.4 megawatt wind energy facility (“Red Lily I”) in south-eastern Saskatchewan.

The equity in Red Lily I (‘the Partnership”) is owned by an independent investor. The Company’s investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Partnership. APUC’s commitment under the senior debt facility is to advance up to $13,000 of the Tranche 2 senior debt. The third party lender has also committed to provide $31,000 of senior debt to the Partnership. The senior debt will earn an interest rate of 6.31% and will mature five years following commissioning of the project. The subordinated debt will earn an interest rate of 12.5%. The senior debt is secured by substantially all the assets of the Partnership.

5. Long-term investments and notes receivable (continued)

(a) Red Lily I (continued)

In 2010, APUC funded $6,100 of senior debt to the project (2009 - $nil) and $6,565 in subordinated debt to the Partnership.

A second tranche of subordinated debt for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced five years following commissioning of the project. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including APUC's portion. The subordinated debt earns an interest rate of 12.5%, the principal matures 25 years following commissioning of the project but is repayable by Red Lily in whole or in part at any time after five years, without a pre-payment premium. The subordinated debt is secured by substantially all the assets of the Partnership but is subordinated to the senior lenders debt.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated debt of up to $19,500, exercisable for a period of 90 days commencing five years from the date of commissioning of the project.

(b) Silverleaf Resorts Inc – Hill County

On July 29, 2010, Liberty Water, a wholly owned subsidiary of APUC, made an investment in its Hill Country facility, a part of Silverleaf Resorts Inc.'s ("SRI") facilities in Comal County, Texas. The investment of $2,094 (U.S. $2,021) was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. This investment has been recorded in property, plant and equipment as additional capacity conveyed by SRI together with note receivable for funds advanced by APUC.

The note has a 10 year term and bears interest at 15.48%. The note is repayable in cash to the extent expansion does not form part of the rate base of the utility during the 10 year term. To the extent that the cost of the expansion becomes part of the rate base of the utility, the note will be assigned as payment to Silverleaf for the expansion costs with the excess received in cash.

(c) Land Fill Gas

In 2009, APUC wrote off the remaining $1,103 (U.S. - $999) principal balance of the note receivable related to its land fill gas facility which was previously recorded in other long term investments.

(in thousands of Canadian dollars except as noted and amounts per share)

6. Property, plant and equipment

Property, plant and equipment consist of the following:

2010

	Cost	Accumulated amortization	Net book value
Land	$ 11,709	$ -	$ 11,709
Facilities	921,032	231,098	689,934
Equipment	48,747	21,314	27,433
	$ 981,488	$ 252,412	$ 729,076

2009

	Cost	Accumulated amortization	Net book value
Land	$ 11,323	$ -	$ 11,323
Facilities	953,826	224,244	729,582
Equipment	30,325	21,880	8,445
	$ 995,474	$ 246,124	$ 749,350

Facilities include cost of $94,606 (2009 - $94,606) and accumulated amortization of $27,962 (2009 - $25,426) related to facilities under capital lease or owned by consolidated variable interest entities, and $10,542 (2009 - $11,551) of construction in process. Amortization expense of facilities under capital lease was $2,536 (2009 - $2,537). In addition $3,731 (2009 - $5,926) of contributions received in aid of construction have been credited to facilities cost. Equipment includes cost of $4,402 (2009 - $4,096) and accumulated amortization of $2,149 (2009 - $1,857) related to equipment under capital lease. Amortization expense of equipment under capital lease was $292 (2009 - $302). In 2010, interest of $nil (2009 - $nil) was capitalized to facilities within property, plant and equipment.

In December 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1,836 representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates.

In December 2010, the equipment at the Crossroads thermal facility in New Jersey met the conditions for asset held for sale. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $656, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

In December 2009, APCo decided to dispose of its investments in its last remaining Landfill Gas assets and its biomass joint venture Drayton Valley Power. APCo therefore tested these investments for recoverability using a net realizeable value valuation technique. As a result, APCo determined that these assets were impaired as at December 31, 2009 and recognized an impairment charge on property, plant and equipment of $5,354 representing the difference between the carrying value of the assets and their net fair value. In 2009 APCo also recorded $500 related to costs associated with decommissioning the land fill gas facilities and recorded this on the Statement of Operations with a corresponding increase in other long term liabilities.

(in thousands of Canadian dollars except as noted and amounts per share)

7. Intangible assets

Intangible assets consist of the following:

2010

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 102,980	$ 45,345	$ 57,635
Customer relationships	18,811	2,912	15,899
Energy sales contract	4,228	3,876	352
Licenses and agreements	683	683	-
	$ 126,702	$ 52,816	$ 73,886

2009

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 119,533	$ 51,333	$ 68,200
Customer relationships	20,279	2,564	17,715
Licenses and agreements	696	682	14
	$ 140,508	$ 54,579	$ 85,929

Estimated amortization expense for intangibles for the next five years is: $6,526 in 2011, $6,120 in 2012, $6,117 in 2013, $6,070 in 2014, and $6,070 in 2015.

8. Other Assets

Other assets consist of the following:

	2010	2009
Regulatory assets	$ 2,164	$ 1,713
California Utility – deferred financing	871	-
California Utility – other capital assets	965	-
Wind development assets	788	788
Deferred transaction costs -		
California Utility (note 4(a))	2,210	1,084
Tinker acquisition (note 4 (c))	-	390
Energy North and Granite State acquisition (note 4(b))	1,888	-
Other	731	867
	$ 9,617	$ 4,842

Regulatory assets are amortized over the period of rate recovery granted by the regulator.

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long-term liabilities

Long term liabilities consist of the following:

	2010	2009
Senior Secured Revolving Credit Facility: Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus 0.95%. The effective rate of interest for 2010 was 2.13% (2009 – 1.71%).	$ 64,500	$ 94,000
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matures on October 31, 2011. Monthly interest and quarterly principal payments totaling $1,741 (2009 - $1,649). The effective rate of interest for 2010 was 1.81% (2009 – 1.78%).	68,789	70,271
Liberty Water Senior Unsecured: U.S. $50,000 senior unsecured note, interest rate of 5.6% matures December 22, 2020. The note is interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and an annual principal repayment of U.S. $5,000 thereafter.	48,876	-
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly installments of $402 and maturing December, 2027.	39,870	40,594
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2010 is 1.33% (2009 – 1.44%).	19,096	20,179
Litchfield Park Service Company Bonds: 1999 and 2001 IDA Bonds. Interest rates of 5.87% and 6.71% repayable in blended semi-annual installments maturing October 2023 and October 2031. Principal payments of U.S. $270 (2009 – U.S. $240). The balance of these notes at December 31, 2010 was U.S. $4,112 and U.S. $7,884, respectively (2009 – U.S. $4,325 and U.S. $7,983).	11,931	12,936
Senior Debt Chute Ford: Interest rate of 11.6% repayable in monthly interest and principal installments of $64 and maturing April, 2020.	4,336	4,580

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long term liabilities (continued)

	2010	2009
Bella Vista Water Loans: Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March, 2020 and December, 2017. The balance of these notes at December 31, 2010 was US$1,384 and US$95 respectively (2009 – US$1,478 and US$102).	1,489	1,707
Bonds Payable: Obligation to the City of Sanger due October 1, 2011 at interest rates varying from 5.45% to 5.55%. U.S. $230 (2009 - U.S. $445).	229	468
Other	15	37
	$ 259,131	$ 244,772
Less: current portion	(70,490)	(3,360)
	$ 188,641	$ 241,412

Subsequent to year end, APCo renewed its senior secured revolving credit facility in the amount of $142,000 (the “Facility”) for a three year term with its Canadian bank syndicate. The Facility now has a maturity date of February 14, 2014.

At December 31, 2010, $64,500 (2009 - $94,000) has been drawn on the Facility. In addition, the availability of the revolving credit facility has been reduced for certain outstanding letters of credit in amounts totaling $33,122 (2009 - $33,108). Therefore, APCo had $44,400 of undrawn committed and available bank facilities as at December 31, 2010.

The terms of the Facility contain certain financial covenants including debt service ratios and various leverage ratios which can limit the amounts available for borrowing. Based on current covenants at December 31, 2010, APCo is able to access the entire amount of the Facility. The facility is secured by a fixed and floating charge over all APCo entities.

On December 22, 2010 APUC completed a $50,000 private placement debt financing commitment for its subsidiary, Liberty Water Co. (“Liberty Water”). The notes are senior unsecured with a ten year maturity date of December 2020 and bears interest at 5.6%. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and annual principal repayments of U.S. $5,000 thereafter. As of December 31, 2010, Liberty Water incurred deferred financing costs of $854 which is amortized to interest expense over the term of the loan using the effective interest rate method.

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long term liabilities (continued)

Total long term debt is reported net of deferred financing costs. Certain of our long-term debt has been issued at a subsidiary level relating to a specific operating facility and is secured by the respective facility with no other recourse to APUC or APCo. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions/dividends to APCo and APUC from specific facilities. As at December 31, 2010 APUC and its subsidiaries were in compliance with all debt covenants.

Interest paid on the long-term liabilities was $9,064 (2009 - $9,446).

Principal payments due in the next five years and thereafter are:

2011	$ 70,490
2012	1,543
2013	1,695
2014	66,354
2015	2,041
Thereafter	117,008
	$ 259,131

The AirSource senior debt matures in October, 2011. As of December 31, 2010, the outstanding amount due has been recorded within the current portion of the long-term liabilities on the Consolidated Balance Sheet.

10. Convertible Debentures

Contemporaneously with the Unit Exchange Offer, on October 27, 2009 (see note 3), holders of APCo's convertible debentures exchanged their convertible debentures for convertible debentures of APUC (the "New Debentures") or for New Common Shares of APUC resulting in APCo's debentureholders becoming debentureholders or shareholders of APUC.

Pursuant to the CD Exchange Offer, $63,755 of the outstanding Series 1 debentures of APCo were exchanged for new Series 1 convertible unsecured subordinated debentures of APUC in a principal amount of $66,943, and $21,209 of the current Series 1 debentures of APCo were exchanged for 6,607,027 shares of APUC. In addition, all of the outstanding Series 2 convertible debentures of APCo were exchanged for New Series 2 convertible unsecured subordinated debentures of APUC in a principal amount of $59,967.

Accounting treatment of the CD Exchange Offer

The terms of the CD Exchange Offer are considered a modification of the terms of the existing debentures of APCo rather than an extinguishment since the present value of the cash flows of the liability component of both the New Series 1 and New Series 2 debentures did not change by more than 10% as compared to the terms of the original debentures exchanged. Accordingly, the consolidated balance sheet reflects the convertible debentures at their original carrying values, net of transaction costs associated with the CD Exchange Offer. These transaction costs are recorded as deferred costs and are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

10. Convertible Debentures (continued):

Under the terms of the CD Exchange Offer, the New Series 1 convertible debentures of APUC were issued at a face value of 105% of the principle amount of the original Series 1 debentures of APCo. The change in conversion price of the New Series 1 convertible debentures under the CD Exchange Offer resulted in the fair value of the conversion feature increasing by $1,179 as compared to the original Series 1 debentures. The change in conversion price of the New Series 2 convertible debentures under the CD Exchange Offer resulted in the fair value of the conversion feature decreasing from the original Series 2 convertible debentures carrying value of $479 to $308. The changes of $1,179 and $171 in the fair value of the conversion features on the Series 1 and Series 2 debentures are recorded as a change in the discount on debt, with an offsetting adjustment to equity. The discounts on debt are treated as additional debt issuance costs which are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

In addition, an element of the CD Exchange Offer to the Series 1 convertible debenture holders was an option to convert a portion of Series 1 convertible debentures to equity at a rate of 311.52 APUC Shares for each $1 principal amount of Series 1 convertible debentures. This resulted in an accounting debt settlement expense of $1,252 which is included in corporatization costs on the consolidated statement of operations. The CD Exchange Offer resulted in the holders of the Series 1 convertible debentures converting $21,209 of the outstanding principal balance of Series 1 convertible debentures into 6,607,027 common shares of APUC.

The pro rata portion of existing deferred financing charges associated with the Series 1 convertible debentures of $306 is recorded in the amount recorded for the common shares issued on conversion. In addition, a proportionate allocation of the total deferred transaction costs associated with the CD Exchange Offer is recorded as part of the issuance costs of the new APUC shares. APUC incurred transaction costs of $1,453 related to the CD Exchange Offer for the Series 1 convertible debentures of which $1,090 is allocated to the convertible debentures as debt issuance costs and $363 has been allocated to issuance costs related to the new APUC shares. APUC also incurred costs of $1,453 related to the CD Exchange Offer for the Series 2 convertible debentures which has been allocated to the convertible debentures as debt issuance costs.

The exchange of $63,755 of Series 1 convertible debentures that were not converted to shares, after adjustment for the 5% premium included in the CD Exchange Offer, resulted in an increase in the principal balance of the new Series 1 convertible debentures to $66,943. The increase of $3,188 is accounted for as additional debt issuance costs and is amortized to interest expense over the term of the new convertible debentures using the effective interest rate method.

10. Convertible Debentures (continued):

On December 2, 2009, APUC issued 63,250 convertible unsecured subordinated debentures (Series 3) at a price of $1 per debenture for gross proceeds of $63,250 and net proceeds of $60,518. The debentures are due June 30, 2017 and bear interest at 7.00% per annum, payable semi-annually in arrears on June 30 and December 31 each year. The convertible debentures are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares per $1 principal amount of debentures. The debentures cannot be redeemed by APUC on or before December 31, 2012. APUC performed an evaluation of the embedded conversion option and determined that its value was $4,275 and as a result this portion of the debenture is classified as equity with the remaining amount classified as a liability. The liability component of the convertible debentures increases to their face value over the term of the debentures and the offsetting charge to earnings is classified as interest expense on the consolidated statements of operations.

Total interest paid on the convertible debentures in 2010 was $13,053 (2009 - $9,696).

(in thousands of Canadian dollars except as noted and amounts per share)

10. Convertible Debentures (continued):

2010	**New Series 1**	**New Series 2**	**Series 3**	**Total**
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$4.08	$6.00	$4.20	
Carrying value at December 31, 2009	60,728	56,241	56,288	173,257
Conversion to shares (Note12), net of costs	(4,094)	-	(311)	(4,405)
Amortization and accretion	1,000	425	698	2,123
Carrying value at December 31, 2010	$57,634	$56,666	$56,675	$170,975
Face value at December 31, 2010	$62,470	$59,967	$62,905	$185,342

2009	**New Series 1**	**New Series 2**	**Series 3**	**Total**
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$4.08	$6.00	$4.20	
Carrying value at December 31, 2008	83,178	57,249	-	140,427
Issued pursuant to December 2, 2009 offering	-	-	63,250	63,250
Change in equity component	(1,179)	171	(4,275)	(5,283)
Conversion to shares (Note12), net of costs	(21,209)	(33)	-	(21,242)
Deferred issue costs	(784)	(1,453)	(2,731)	(4,968)
Amortization and accretion	722	307	44	1,073
Carrying value at December 31, 2009	$60,728	$56,241	$56,288	$173,257
Face value at December 31, 2009	$66,943	$59,967	$63,250	$190,160

(in thousands of Canadian dollars except as noted and amounts per share)

11. Other long-term liabilities

Other long term liabilities consist of the following:

	2010	2009
Advances in aid of construction (note 1(l))	$ 21,267	$ 14,952
Deferred water rights inducement	3,008	3,089
Customer deposits	1,985	2,405
Capital Leases		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	524	456
Other	5,099	5,351
	31,883	26,253
Less: current portion	(1,011)	(1,025)
	$ 30,872	$ 25,228

Principal payments due in the next five years and thereafter are:

2010	$ 1,011
2011	165
2012	78
2013	68
2014	-
Thereafter	30,561
	$ 31,883

Interest paid on other long-term liabilities was $29 (2009 - $37).

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' equity/Unitholders' equity

Number of common shares/trust units:

	2010	2009
Common shares / Trust units, beginning of period	93,064,120	77,574,372
Issued on conversion of Algonquin (AirSource) Power LP exchangeable units	-	2,005,721
Conversion of convertible debentures (Note 11)	1,178,478	6,607,027
Issued pursuant to management internalization	1,180,180	-
Issued pursuant to offering	-	6,877,000
Common shares, end of period	95,422,778	93,064,120

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are outstanding**.**

On October 27, 2009, pursuant to the Unit Exchange Offer (see note 3), APCo's unitholders exchanged 100% of the outstanding trust units of APCo for a new class of common shares ("New Common Shares") of APUC on a one for one basis. As a result, the existing unitholders of APCo became shareholders of APUC and APCo became a subsidiary of APUC.

On December 2, 2009, APUC issued 6,877,000 common shares at $3.35 per common share for gross proceeds of $23,038 before issuance costs of $1,495, ($1,002 net of tax) for net proceeds of $21,533.

On June 29, 2010, the Company issued 1,180,180 shares valued at $4,763 pursuant to the Management Internalization Agreement signed on December 21, 2009 (note 16). The issuance of shares and final settlement was approved by the Company's shareholders at its annual general meeting held on June 23, 2010.

In 2010, $4,473 principal amount of New Series 1 Debentures were converted at the option of the holders at a price of $4.08 for each share into 1,096,335 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $4,094 has been recorded as share capital.

In 2010, $345 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 82,142 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $311 has been recorded as share capital.

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' equity/Unitholders' equity (continued):

At a special meeting of Exchangeable Unitholders of Algonquin (AirSource) Power LP in December 2009, amendments were approved to amend the agreements related to the Exchangeable Units to allow the exchange of Exchangeable Units for common shares of APUC, as opposed to units of APCo, and to change the definition of "Redemption Date" as set out in the Partnership Agreement. As a result of these changes, APUC exercised the compulsory acquisition provisions of the Exchangeable Units on December 31, 2009 and all of the remaining outstanding Exchangeable Units were exchanged for 532,074 common shares of APUC, as per the formula set out in the original agreements. As a result, there are no outstanding Exchangeable Units after January 1, 2010 and consequently the non-controlling interest balance at December 31, 2010 is reduced to $nil (2009 - $nil). At December 31, 2010 no amount was included in non-controlling interest (2009 - $1,928) in the statement of operations for the allocation of earnings to the exchangeable unitholders (AirSource Power LP).

Shareholders equity/Unitholders' Equity consists of the following:

	2010	2009
Balance of Common shares/Trust Units, beginning of period	$ 781,274	$ 721,953
Issued on conversion of Airsource exchangeable units	-	14,487
Conversion of convertible debentures, net of costs	4,621	21,825
Common Share issue, net of costs	-	22,026
Common shares issued pursuant to management internalization (Note 14)	4,763	-
Proceeds from liquidation of Highground assets (Note 4(f))	170	983
Balance of Shares, end of the period	$ 790,828	$ 781,274
Contributed surplus – stock options	108	-
Equity component of convertible debentures (Note 10)	5,640	5,763
Shareholders' equity, end of period	$ 796,576	$ 787,037

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' capital (continued)

Stock Option Plan

On June 23, 2010, the Company's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Optionholders may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of a qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

On August 12, 2010, the Board approved the grant of 1,102,041 options to senior executives of the Company. The options allow for the purchase of common shares at a price of $4.05, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2011, 2012 and 2013. Options may be exercised up to eight years following the date of grant.

The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The following assumptions were used in determining the fair value of share options granted:

	2010
Risk-free Interest	2.9%
Expected Volatility	29.2%
Expected dividend yield	5.9%
Expected Life	8 years
Grant date fair value per option	$ 0.61

The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical rates in dividends of our shares.

12. Shareholders' capital (continued)

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. At December 31, 2010, APUC recorded $108 (2009 - $nil) in compensation expense. As at December 31, 2010, there was $562 (2009 - $nil) of total unrecognized compensation costs related to non-vested options granted under the Plan. The cost is expected to be recognized over a period of 1.9 years.

No share options were exercised in 2010 or exercisable at December 31, 2010. The intrinsic value of the 1,102,041 non-vested shares as at December 31, 2010 was $1,069 (2009- $nil).

Shareholders' Rights Plan

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan").

The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(in thousands of Canadian dollars except as noted and amounts per share)

13. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 31% (2009 - 33%). The differences are as follows:

	2010	2009
Expected income tax expense / (recovery) at Canadian statutory rate	$ (45)	$ 5,302
Increase (decrease) resulting from:		
Accounting losses (income) of APCo taxed at the unitholder level	-	(20,790)
Recognition of deferred credit	(6,636)	-
Differences in tax rates in subsidiaries and changes in tax rates	(203)	(1,848)
Change in valuation allowances	(7,486)	10,688
Foreign exchange loss on intercompany items (US)	(6,228)	(13,464)
Non deductible expenses and other	370	2,185
Income tax recovery	$ (20,228)	$ (17,927)

The Unit Exchange Offer (Note 3), together with changes in tax rates enacted in December 2009, resulted in APUC recognizing a future income tax asset of $60,014 and a deferred credit in relation to this asset of $49,879 as at December 31, 2009. The deferred credit is being recorded to reduce income tax expense in proportion to the net reduction in the future income tax asset that gave rise to the deferred credit. Current and future income taxes have been provided in respect of taxable income and temporary differences related to the Company and its subsidiaries.

For the years ended December 31, 2010 and 2009, income/(loss) before taxes consists of the following:

	2010	2009
Canadian operations	$ (4,152)	$ 7,284
U.S. operations	4,007	8,783
	$ (145)	$ 16,067

(in thousands of Canadian dollars except as noted and amounts per share)

13. Income taxes (continued)

Income tax expense attributable to income/(loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2010			
Canada	$ 200	$ (518)	$ (318)
United States	(269)	(19,641)	(19,910)
	$ (69)	$ (20,159)	$ (20,228)
Year ended December 31, 2009			
Canada	$ 313	$ 4,481	$ 4,794
United States	84	(22,805)	(22,721)
	$ 397	$ (18,324)	$ (17,927)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2010 and 2009 are presented below:

	2010	2009
Future tax assets:		
Non-capital losses, investment tax credits, currently non-deductible interest expense and financing costs	$ 115,472	$ 104,455
Unrealized foreign exchange differences on intercompany notes	17,860	25,138
Customer advances in aid of construction	5,559	5,393
Foreign exchange hedges and interest rate swaps	1,459	2,865
Total future tax assets	140,350	137,851
Less: Valuation allowance	(27,907)	(35,393)
Total future tax assets	112,443	102,458
Future tax liabilities:		
Property, plant and equipment	(96,554)	(96,960)
Intangible assets	(7,639)	(8,409)
Other	(1,696)	(2,131)
Total future tax liabilities	(105,889)	(107,500)
Net future tax asset / (liability)	$ 6,554	$ (5,042)

The valuation allowance for future tax assets as of December 31, 2010 and 2009 was $27,907 and $35,393, respectively. The net change in the total valuation allowance was a decrease of $7,486 in 2010 and an increase of $10,688 in 2009. The valuation allowance at December 31, 2010 was primarily related to operating losses and foreign exchange losses on the intercompany debts that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of future tax assets, management considers whether it is more likely than not that some portion or all of the future tax assets will not be realized. The ultimate realization of future tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of future tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax-planning strategies in making this assessment.

(in thousands of Canadian dollars except as noted and amounts per share)

13. Income taxes (continued)

Future income taxes are classified in the financial statements as:

	2010	2009
Future current income tax asset	$ 14,015	$ 14,566
Future non-current income tax asset	74,006	61,219
Future current income tax liability	(514)	(913)
Future non-current income tax liability	(80,953)	(79,914)
	$ 6,554	$ (5,042)

As at December 31, 2010, the Company had non capital loss carryforwards available to reduce future years taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforward
2014	$ 29,023
2015	33,957
2019	135,095
2020 and onwards	69,604
	$ 267,679

14. Related party transactions

On December 21, 2009, the Board of Directors of APUC (the "Board") reached an agreement with APMI to internalize all management functions of the APCo which were provided by APMI. APUC acquired APMI's interest in the management services agreement, with consideration paid in the form of issuance of 1,158,748 APUC shares (the "Shares"). For accounting purposes, the expense has been measured at $4,693 using a price for each share of $4.03, the adjusted closing market price on December 21 2009, the date the agreement was ratified.

Up to December 21, 2009, APMI provided management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2009, APMI was paid on a cost recovery basis for all costs incurred and charged $850. APMI was also entitled to an incentive fee of 25% on all distributable cash (as defined in the management agreement) generated in excess of $0.92 per trust unit.

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for 2010 were $327 (2009 - $331).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year, APUC incurred costs in connection with the use of the aircraft of $430 (2009 - $367) and amortization expense related to the advance against expense reimbursements of $112 (2009 - $153). At December 31, 2010, the remaining amount of the advance was $554 (2009 - $666) and is recorded in other assets.

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008 growing to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units are entitled to cash distributions of $266 for the year ended December 31, 2010 (2009 - $292).

Pursuant to the agreement entered into on June 27, 2008 between the Company, Highground and CJIG (Note 4(f)), APMI was entitled to a fee of approximately $240 from the Company. This fee was paid in 2009.

14. Related party transactions (continued)

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1,800 of which APUC agreed to pay APMI $105. This amount has been accrued and included in accounts payable on the consolidated balance sheet.

APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. APUC has agreed to acquire APMI's interest in this royalty for an amount of $600. APMI is also entitled to a development fee of up to $400 following commercial operation of the project and has agreed to permit the Board to determine the portion of such fee which will be paid following commercial operation of the facility. APUC received and recognized $210 in other revenue related to this fee in the twelve months ended December 31, 2010.

APUC has operation and maintenance service agreements with three hydroelectric generating facilities owned by affiliates of APMI. As a result of these agreements, APUC employees operate these hydroelectric generating facilities owned by affiliates of APMI. These facilities are charged on a cost recovery basis for time and material incurred at these sites.

Under these arrangements, as at December 31, 2010 amount due from the above related party transactions was $718 (December 31, 2009 - $1,028) and amounts due to related parties was $901 (December 31, 2009 - $827).

A member of the Board of Directors of APUC is an executive at Emera Inc ("Emera"). A contract with a subsidiary of Emera to purchase energy on Independent System Operator New England ("ISO NE") and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of $1,368 (2009 - $nil) which was included as an operating expense on the consolidated statement of operations.

In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During 2010 APUC paid U.S. $196 (2009 - $nil) in relation to this contract. In the same period, APUC issued a letter of credit to a subsidiary of Emera in an amount of U.S. $500 in conjunction with this contract. Subsequent to December 31, 2010, this letter of credit was replaced with a corporate guarantee.

On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation), the parent company of Maine Public Service Company ("MPS"). Subsequent to the date of this acquisition, the Energy Services Business sold electricity of U.S. $144 (2009 – nil) to MPS.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

15. Commitments and Contingencies

(a) Land and Water Leases

Certain of the Company's operating entities have entered into agreements to lease either land, water rights or both that are used in the generation of electricity or to pay, in lieu of property tax, an amount based on electricity production. The terms of these leases have varying maturity dates that continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. APUC incurred costs of $2,231 during 2010 (2009 - $2,823) in respect of these agreements for all of its operating entities.

(b) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

(c) Commitments

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated potential remedial measures involving capital expenditures of approximately $17,129 which may be required to comply with the legislation and which would be invested over a five year period or longer. APUC continues to explore alternatives to reduce or mitigate these potential capital expenditures, including technical alternatives and cost sharing with other stakeholders.

An AirSource affiliate, St. Leon Wind Energy LP ("St. Leon LP") has entered into right-of-way agreements (collectively, the "Land Rights"), with approximately 50 local landowners, providing for a minimum term of 40 years. The Land Rights agreements provide for an annual rent payable per MW-hr generated from turbines installed on the land rented, subject to a minimum payment per wind turbine. Land without wind turbines is leased at a cost on a per acre basis. The total commitment over the term of the St. Leon power purchase agreement is estimated at $3,605.

16. Cash dividends

All cash dividends of the Company are made on a discretionary basis as determined by the Board of Directors of the Company. In 2010, the Company paid quarterly dividends of $0.06 per share. For the year ended December 31, 2010, the Company paid cash dividends to shareholders totaling $22,765 (2009 - $18,999) or $0.24 per unit / per share (2009 - $0.24).

Total distributions to the unitholders of the AirSource exchangeable units for 2010 were $nil (2009 - $323) which was recorded as a reduction in non controlling interest on the consolidated balance sheet.

(in thousands of Canadian dollars except as noted and amounts per share)

17. Non cash working capital and Supplemental cashflow Information

The change in non cash working capital is comprised of the following:

	2010	2009
Accounts receivable	$ (6,813)	$ 6,720
Income tax receivable	1,143	395
Prepaid expenses	1,153	(1,842)
Accounts payable and accrued liabilities	5,050	(6,042)
Current income tax liability	195	(536)
	$ 728	$ (1,305)

The following table sets forth non-cash investing and financing activities and other cash flow information:

	2010	2009
Taxes & Interest paid:		
Income taxes paid / (received)	$ (285)	$ 873
Interest paid	$ 21,562	$ 19,956
Non-cash transactions:		
Property installed by developers and conveyed	$ 2,541	$ 223

18. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of the weighted average number of shares outstanding during the year. The weighted average number of shares outstanding during the year are as follows:

	2010	2009
Weighted average shares – basic	94,338,193	79,830,906
Shares issuable on conversion of AirSource exchangeable units	-	1,499,222
Weighted average shares – diluted	94,338,193	81,330,128

Shares or Trust units issuable on conversion of exchangeable units are calculated at the year end based on the weighted average exchangeable units outstanding during the year and applying the rate of exchange. The shares potentially issuable as a result of the convertible debentures and under stock option plans are excluded from this calculation as they are anti-dilutive.

(in thousands of Canadian dollars except as noted and amounts per share)

19. Interest, dividend and other income

Interest, dividend and other income includes the following items:

	2010	2009
Interest income	$ 1,138	$ 710
Dividend income	2,928	2,928
Equity income	431	361
Gain on sale of land and land rights	-	1,451
Other	465	951
	$ 4,962	$ 6,401

20. Other revenue

Other revenue consists of the following:

	2010	2009
Natural gas sales	$ (109)	$ 588
Hydro mulch sales	1,318	3,260
Red Lily development fees	209	-
Red Lily construction services	1,913	-
	$ 3,331	$ 3,848

21. Segmented Information

APUC has two broad operating segments: APCo which owns or has interests in 48 renewable energy facilities and 14 thermal energy facilities representing more than 490 MW of installed electrical generation capacity; and Liberty Utilities which owns and operates 19 utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois.

Within APCo there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Within Liberty Utilities, Liberty Water provides transportation and delivery of water and wastewater in its service areas.

The operations and assets for these segments are as follows:

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy and Liberty Water. The development activities are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the gain on financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. Dividend income was previously allocated to the Thermal division based on the operations of the underlying investment. In 2010, Management reviewed the performance of these investments separately from the facilities that the Company manages directly. Interest expense is allocated to the divisions based on the project level debt related to the facilities in each division. Interest expense on the revolving credit facility and other administrative costs were previously allocated to the corporate segment. In 2010, Management's evaluation of divisional performance considered an allocation between the reporting segments based on a percentage of the reporting segments share of the total property, plant and equipment and intangible assets. The interest rate swaps relate to specific debt facilities and gains and losses are allocated in the same manner as interest expense. Amounts relating to the convertible debentures are reported in the corporate segment. The comparative figures have been reclassified to conform to the allocation adopted this year.

The operations and assets for these segments are as follows:

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

Year ended December 31, 2010						
	Algonquin Power			Liberty Utilities	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 80,117	$52,609	$132,726	$ -	$ -	$132,726
Waste disposal fees	-	9,039	9,039	-	-	9,039
Water reclamation and distribution	-	-	-	37,786	-	37,786
Other revenue	2,122	1,209	3,331	-	-	3,331
Total revenue	82,239	62,857	145,096	37,786	-	182,882
Operating expenses	29,481	46,296	75,777	22,074	-	97,851
	52,758	16,561	69,319	15,712	-	85,031
Other administration costs	(4,674)	(1,825)	(6,499)	(1,890)	(6,497)	(14,886)
Foreign exchange loss	-	-	-	-	528	528
Interest expense	(7,742)	(782)	(8,524)	(1,908)	(15,180)	(25,612)
Interest, dividend and other income	783	495	1,278	85	3,599	4,962
Gain / (loss) on derivative financial instruments	(5,486)	-	(5,486)	-	4,383	(1,103)
Write down of property plant and equipment	(1,836)	(656)	(2,492)	-	-	(2,492)
Amortization of property, plant and equipment	(17,233)	(11,362)	(28,595)	(7,659)	(175)	(36,429)
Amortization of intangible assets	(6,670)	(2,774)	(9,444)	(700)	-	(10,144)
Net earnings / (loss) before income taxes, and non-controlling interest	9,900	(343)	9,557	3,640	(13,342)	(145)
Property, plant and equipment	$412,549	$151,260	$563,809	$164,775	$492	$729,076
Intangible assets	28,287	23,104	51,391	22,495	-	73,886
Total assets	467,979	195,181	663,160	205,770	111,987	980,917
Capital expenditures	2,331	11,596	13,927	6,644	260	20,831
Acquisition of operating entities	40,281	-	40,281	5,243	-	45,524

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

Year ended December 31, 2009						
	Algonquin Power			Liberty Utilities	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 68,227	$62,209	$130,436	$ -	$ -	$130,436
Waste disposal fees	-	14,468	14,468	-	-	14,468
Water reclamation and distribution	-	-	-	38,513	-	38,513
Other revenue	-	3,848	3,848	-	-	3,848
Total revenue	68,227	80,525	148,752	38,513	-	187,265
Operating expenses	22,279	57,299	79,578	23,158	-	102,736
	45,948	23,226	69,174	15,355	-	84,529
Other administration costs	(5,791)	(2,812)	(8,603)	(226)	(2,733)	(11,562)
Foreign exchange loss	-	-	-	-	1,261	1,261
Interest expense	(7,345)	(1,098)	(8,443)	(2,049)	(10,895)	(21,387)
Interest, dividend and other income	1,226	821	2,047	1,368	2,986	6,401
Gain / (loss) on derivative financial instruments	2,682	(829)	1,853	343	15,122	17,318
Write down of property plant and equipment	-	(5,354)	(5,354)	-	-	(5,354)
Write down of note receivable	-	(1,103)	(1,103)	-	-	(1,103)
Amortization of property, plant and equipment	(16,934)	(13,087)	(30,021)	(8,557)	-	(38,578)
Amortization of intangible assets	(2,654)	(3,916)	(6,570)	(735)	-	(7,305)
Earnings / (loss) from operations before income taxes, non-controlling interest, and corporatization costs	17,132	(4,152)	12,980	5,499	5,741	24,220
Management internalization costs	-	-	-	-	(4,693)	(4,693)
Other corporatization costs	-	-	-	-	(3,460)	(3,460)
Net earnings / (loss) before income taxes, and non-controlling interest	17,132	(4,152)	12,980	5,499	(2,412)	16,067
Property, plant and equipment	$403,192	$176,171	$579,363	$169,987	$-	$749,350
Intangible assets	30,602	30,436	61,038	24,891	-	85,929
Total assets	451,936	245,582	697,518	203,444	112,451	1,013,413
Capital expenditures	1,114	3,521	4,635	6,174	107	10,916
Acquisition of operating entities	-	-	-	(1,177)	-	(1,177)

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2010 or 2009: Hydro Québec 14% (2009 - 17%), Pacific Gas and Electric 10% (2009 - 12%), Manitoba Hydro 15% (2009 – 15%), and Connecticut Light and Power 4% (2009 - 18%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

Geographic Segments

APUC and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2010	2009
Revenue		
Canada	$ 75,108	$ 82,364
United States	107,774	104,901
	$ 182,882	$ 187,265
Property, plant and equipment		
Canada	$ 466,205	$ 440,490
United States	262,871	308,860
	$ 729,076	$ 749,350
Intangible assets		
Canada	$ 43,305	$ 47,916
United States	30,581	38,013
	$ 73,886	$ 85,929
Other assets		
Canada	$ 1,414	$ 1,916
United States	8,203	2,926
	$ 9,617	$ 4,842

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments

a) Fair Value of financial instruments

	Carrying amount 2010	Fair value 2010	Carrying amount 2009	Fair value 2009
Cash	5,146	5,146	2,796	2,796
Short-term investments	3,674	3,674	40,010	40,010
Accounts receivable	27,082	27,082	20,484	20,484
Restricted cash	3,563	3,563	4,316	4,316
Notes receivables	18,744	18,744	4,460	4,460
Total financial assets	58,209	58,209	72,066	72,066
Accounts payable and accrued liabilities	33,506	33,506	33,219	33,219
Dividends payable	5,721	5,721	1,857	1,857
Long-term liabilities	259,131	261,321	244,772	247,119
Other long-term liabilities	31,883	31,883	26,253	26,253
Convertible debentures	170,975	216,769	173,257	198,892
Interest swaps	5,440	5,440	8,226	8,226
Energy forward purchase	378	378	-	-
Foreign exchange contracts	45	45	1,469	1,469
Total financial liabilities	507,079	555,063	489,053	517,035

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value at December 31, 2010 and 2009 due to the short-term maturity of these instruments.

Long term investments and notes receivable include equity instruments and notes receivable. The equity instruments do not have a quoted market price in an active market, and fair value cannot be reliably measured. Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities and convertible debentures at fixed interest rates and variable rates. The estimated fair value is calculated using the current interest rates.

Advances in aid of construction included in other long-term liabilities (note – 1 (l)) do not bear interest and the amount to be repaid is subject to uncertainty and estimation. The carrying value is estimated based on historical payment patterns with the amount estimated to not be paid being recorded as a contribution in aid of construction which reduces the carrying amount of the related assets. The fair value is considered to approximate the book value.

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments (continued)

b) Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2010 are as follows:

	Level 1	Level 2	Level 3	Total
Interest swap –St Leon	-	5,440	-	5,440
Energy forward purchase	-	378	-	378
Foreign exchange contracts	-	45	-	45
Total financial liabilities at fair value	-	5,863	-	5,863

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or lever 3 during the year ended December, 31, 2010. No assets or liabilities are measured at fair value on a recurring basis using unobservable inputs (Level 3).

c) Effect of derivative instruments on the Consolidated Statement of Operations

Loss/(gain) on derivative financial instruments consist of the following:

	2010	2009
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (1,424)	$ (15,682)
Interest rate swaps	(2,787)	(7,424)
Energy forward purchase contracts	(2,931)	-
Total change in unrealized loss/(gain) on derivative financial instruments	$ (7,142)	$ (23,106)
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (620)	$ 284
Interest rate swaps	5,929	5,504
Energy forward purchase contracts	2,936	-
Total realized loss/(gain) on derivative financial instruments	$ 8,245	$ 5,788
Loss/(gain) on derivative financial instruments	$ 1,103	$ (17,318)

22. Financial instruments (continued)

(d) Risk Management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents and accounts receivable. The Company limits its exposure to credit risk with respect to cash equivalents by maintaining minimal cash balances and ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from Power Generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of US$4,996 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments (continued)

Credit Risk (continued)

As at December 31, 2010 the Company's exposure to credit risk for these financial instruments was as follows:

	December 31, 2010	
	Canadian $	US $
Cash and cash equivalents	$ 1,878	$ 3,285
Short term investments	-	3,694
Accounts receivable	11,877	15,328
Allowance for Doubtful Accounts	-	(40)
Note Receivable	16,733	2,021
	$ 30,488	$ 24,288

There are no material past due amounts in accounts receivable.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2010, in addition to cash on hand of $5,146 the Company had $44,400 available to be drawn on its senior debt facility. The senior credit facility contains covenants which may limit amounts available to be drawn.

	Total	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations	$ 259,131	$ 70,490	$ 3,238	$ 68,395	$ 117,008
Convertible Debentures	185,342	-	-	62,469	122,873
Interest on long term debt obligations	164,830	25,670	48,198	35,889	55,073
Accounts Payable	33,506	33,506	-	-	-
Derivative financial instruments:					
Currency Forwards	45	45	-	-	-
Interest Rate Swaps	5,439	1,959	2,504	976	-
Commodity Swap	378	378	-	-	-
Lease Payments	523	212	243	68	-
Other obligations	9,255	466	931	931	6,927
Total obligations	$658,449	$132,726	$ 55,114	$ 168,728	$301,881

22. Financial instruments (continued)

Foreign Currency Risk

The Company uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts. Based on the fair value of the forward contracts using the exchange rates as at December 31, 2010, the exercise of these forward contracts will result in the use of $45 in fiscal 2012. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of $0.10 at December 31, 2010 with a corresponding change in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $300, increasing the expected cash generated during fiscal 2012 by $300.

As at December 31, 2010, APUC had outstanding foreign exchange forward contracts to sell US$3,000 (2009 - $39,760) at an average rate of $1.00 (2009- $1.02) and having a fair value liability of $45 (2009 - $1,469).

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility as well as interest earned on its cash on hand. The Company has performed sensitivity analysis on interest rate risk at December 31, 2010 to determine how a change in interest rates would impact equity and net earnings:

Senior credit facility

The Company's senior debt facility has a balance of $64,500 as at December 31, 2010. Assuming the current level of borrowings, a 1% change in the variable rate charged would impact interest expense by $645 during the twelve months ended December 31, 2010. Although this underlying debt with the project lenders carries a variable rate of interest tied to Canadian Bank's prime rate, the Company had previously entered into a fixed for floating interest rate swap related to $100,000 of this debt covering the period between June 30, 2008 and December 2010. APUC effectively fixed its interest expense on this portion of the facility at a rate of 3.24% in 2009 and 4.18% in 2010. At December 31, 2010, the fair value of the interest rate swap was $nil as it had expired (2009 - $3,260 liability). This swap arrangement requires the payment of a fixed rate of interest by the Company in exchange for receipt of a variable rate of interest. The Company has not used hedge accounting for this instrument and therefore changes in fair value are recorded in earnings as they occur and form part of the gain or loss on financial instruments on the consolidated statements of operations.

22. Financial instruments (continued)

Airsource –St Leon

The Algonquin (AirSource) Power LP ("Airsource") project debt at the St. Leon facility has a balance of $68,789 as at December 31, 2010. Assuming the current level of borrowings, a 1% change in the variable rate charged would have impacted interest expense by $687 during the twelve months ended December 31, 2010. Although this underlying debt with the project lenders carries a variable rate of interest tied to Canadian Bank's prime rate, in 2006 the Company entered into a fixed for floating interest rate swap related to this debt until September 2015. This swap arrangement requires the payment of a fixed rate of interest by the Company in exchange for receipt of a variable rate of interest that mirrors the underlying debt's interest payment schedule. These payments effectively minimize volatility in the cash interest on this debt facility through an offset for any change to interest payments as a result of market rate fluctuations. At December 31, 2010, the fair value of the interest rate swap was a net $5,440 liability (2009 - $4,966). APUC has elected not to use hedge accounting for the swap transaction and records the fair value of the swap on the consolidated balance sheets. Any gain or loss in fair value is recognized in the consolidated statements of operations.

Sanger

The Company's project debt at the Sanger facility has a balance of U.S. $19,200 as at December 31, 2010. Assuming the current level of borrowings, a 1% change in the variable interest rate charged would impact interest expense by $192 during the twelve months ended December 31, 2010. This analysis assumes that all other variables, in particular foreign currency rates, remain constant.

Market Risk

APUC provides energy requirements to various customers under contract at fixed rates. While the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

APUC anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In 2010, APUC acquired short term forward energy purchase contracts from the Tinker Acquisition related to the energy services business. APUC has committed to acquire approximately 12,000 MW-hrs of energy over the next 2 months at an average rate of approximately $70.00 per MW-hr. The fair value of these forward energy hedge contracts at December 31, 2010 was a net liability of $378 (2009 - $nil).

23. Capital disclosures

The Company views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

The Company's objectives when managing capital are:

- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital.
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets.
- To ensure generation of cash is sufficient to fund sustainable distributions to Unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

The Company monitors its cash position on a regular basis to ensure funds are available to meet current operating as well as capital expenditures. In addition, the Company regularly reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

(in thousands of Canadian dollars except as noted and amounts per share)

24. U.S. GAAP Reconciliation

The Company follows generally accepted accounting principles in Canada (GAAP), which differs in certain material respects from generally accepted accounting principles in the United States and from practices prescribed by the United States Securities and Exchange Commission (U.S. GAAP). The following information reconciles these consolidated financial statements to U.S. GAAP.

Reconciliation of net earnings under Canadian GAAP to U.S. GAAP

	Year ended December 31	
	2010	**2009**
Net earnings, Canadian GAAP	$ 19,639	$ 31,257
Adjustments, net of tax of $563 (2009- $991)		
Convertible debentures (b),(d)	572	(1,850)
Deferred transaction costs (f)	(2,261)	(1,106)
Non controlling interest (c)	-	2,251
Total adjustments	(1,689)	(705)
Net earnings, U.S. GAAP	17,950	30,552
Other comprehensive income/(loss), Canadian and U.S. GAAP	(51,133)	(27,270)
Total comprehensive income/(loss), U.S. GAAP	(33,182)	3,282
Basic net earnings per share	$0.19	$0.38
Diluted net earnings per share	$0.19	$0.38

The Application of U.S. GAAP results in difference to the following balance sheet items:

	December 31, 2010		December 31, 2009	
	Canadian GAAP	**U.S. GAAP**	**Canadian GAAP**	**U.S. GAAP**
Property, plant and equipment	729,076	728,686	749,350	749,350
Other assets – deferred transaction costs (f)	4,098	-	1,474	-
Deferred financing costs (b(iii),(e))	258	5,991	200	6,001
Long-term liabilities (e)	259,131	259,973	244,772	244,970
Convertible debentures (b(iii),(e)(d)	170,975	181,758	173,257	185,600
Future income tax liability (h)	81,467	79,956	80,827	79,879
Non-controlling interest (c)	-	-	-	-
Temporary equity (a), (c)	-	-	-	-
Additional paid-in-capital (b(ii)),(g)	-	1,496	-	1,487
Shareholders' capital (a),(b),(c),(d),(g)	796,576	795,443	787,037	785,827
Deficit	(347,802)	(357,034)	(344,676)	(352,219)

(in thousands of Canadian dollars except as noted and amounts per share)

24. US GAAP Reconciliation (continued)

Reconciliation of deficit under Canadian GAAP to U.S. GAAP

	As at December 31	
	2010	**2009**
Deficit, Canadian GAAP	$ (347,802)	$ (344,676)
Adjustments, net of tax		
Convertible debentures (b), (d)	(1,311)	(1,883)
Non controlling interest (c)	(4,554)	(4,554)
Deferred transaction costs (f)	(3,367)	(1,106)
Total adjustments	(9,232)	(7,543)
Deficit, U.S. GAAP	$ (357,034)	$ (352,219)

Description of significant differences

a) Unit Exchange Offer

On October 27, 2009, Algonquin Power Income Fund (the "Fund") completed a reverse take-over transaction (the "Transaction") of Hydrogenics Corporation ("Hydrogenics") which resulted in the Fund's Unitholders becoming shareholders in Hydrogenics which was immediately renamed Algonquin Power & Utilities Corp. As a result, the Fund itself became a wholly owned subsidiary of APUC. For Canadian and U.S. GAAP purposes, APUC is considered a continuation of the Fund except for the legal capital of the Fund which is adjusted to reflect the legal capital of APUC.

Prior to the Transaction, the Fund's trust units contained a redemption feature which was required for the Fund to retain its Canadian mutual fund trust status. For Canadian GAAP purposes, the Trust units were considered permanent equity and were presented as a component of Unitholders' equity. Under U.S. GAAP, equity with a redemption feature is presented outside of permanent equity, as temporary equity between the liability and equity sections of the balance sheet. As such, the trust units of $721,736 were reclassed from permanent equity to temporary equity for U.S. GAAP purposes up to October 27, 2009.

24. US GAAP Reconciliation (continued)

b) CD Exchange Offer

Contemporaneously with the Unit Exchange Offer, on October 27, 2009 a convertible debenture exchange offer (the "CD Exchange Offer") was made by APUC to debentureholders of the Fund to allow them to receive debentures issued by APUC.

(i) Similar to Canadian GAAP, under U.S. GAAP the change in coupon rates and maturity terms of the convertible debentures under the CD Exchange Offer is considered to be a debt modification and not an extinguishment based on the Company's evaluation of the changes in cash flows and fair value of the conversion options under the terms of the revised debt agreements. The consolidated balance sheet of APUC under Canadian GAAP reflects the convertible debentures at their original carrying values, net of an allocation of transaction costs of approximately $2,544 associated with the CD Exchange Offers. Under U.S. GAAP these transaction costs of $2,544 were expensed when incurred in 2009 since the costs were paid to third parties and not the debtor. This results in a reduction of $337 (2009 - $53) in the amount of effective interest on convertible debentures under U.S. GAAP in comparison to Canadian GAAP.

(ii) The change in conversion price of the Series 1 and Series 2 convertible debentures under the CD Exchange Offer results in a change in the fair value of the conversion feature of $1,179 and $308, respectively. Under U.S. GAAP, the combined fair value of the conversion feature of $1,487 is recorded as a discount on debt, with an offsetting entry to additional paid-in-capital. Under Canadian GAAP, the offsetting entry is recorded in equity. An adjustment of $1,388 (2009 – 1,487), net of a converted portion of $99 (2009 - $nil) reflects the reclassification of conversion feature recorded as equity under Canadian GAAP, to additional paid-in capital under U.S. GAAP.

(iii) Under U.S. GAAP the adjustment for the conversion of $21,209 of the Series 1 convertible debentures into common shares does not result in any Canadian GAAP difference in earnings.

However, under Canadian GAAP the pro rata share of existing deferred financing charges associated with the Series I debentures of $306 is recorded as a charge against equity upon conversion of $21,209 of debentures into common shares, with a corresponding adjustment to convertible debentures. Under U.S. GAAP, the same net amount is charged against equity however, the corresponding adjustment of $306 is made to deferred financing costs to reflect the different classification of deferred charges for Canadian and U.S. GAAP purposes.

24. US GAAP Reconciliation (continued)

c) Non controlling interest

Exchangeable units ("AirSource Exchangeable Units") were issued by Algonquin (AirSource) Power LP ("Algonquin AirSource"), a subsidiary of the Fund, when Algonquin AirSource acquired AirSource Power Fund I LP on June 29, 2006. The AirSource Exchangeable Units entitled the holders to receive distributions which are equivalent to the Fund's distributions, as long as the facility which was acquired upon acquisition of AirSource generated adequate cash flows.

Under Canadian GAAP the AirSource Exchangeable Units were recorded in the Company's consolidated financial statements as "Non controlling interest". The portion of income or loss attributable to this non controlling interest and distributions to holders of the exchangeable units are recorded as a reduction to the carrying amount of the non controlling interest. Under U.S. GAAP the AirSource Exchangeable Units are classified along with the Trust Units outside of permanent equity as temporary equity since they are able to be converted at the holder's option to the Fund's Trust Units. The temporary equity was initially recorded at an amount equal to the redemption value based on the terms of the AirSource Exchangeable Units. Any increase in the redemption value of the AirSource Exchangeable Units is recorded as an adjustment through deficit and any downward adjustment is restricted only to the extent of previously recorded increases in the carrying amount arising from such adjustments. No adjustment was required to the carrying amount of the AirSource Exchangeable Units in temporary equity. Under U.S. GAAP the proportion of income attributable to the AirSource Exchangeable Units non controlling interest of $nil (2009 - $2,251) is recorded to deficit rather than through earnings and distributions to the AirSource Exchangeable Unit holders of $nil (2009 - $323) are recorded as a charge to deficit.

On December 31, 2009, all remaining Air Source units were converted to APUC shares. Under both Canadian and U.S. GAAP, when the AirSource Exchangeable Units are converted to shares, the non controlling interest (temporary equity under U.S. GAAP) on the consolidated balance sheet is reduced on a pro-rata basis together with a corresponding increase in shares. However, since the carrying amount of the non-controlling interest per Canadian GAAP differs from the carrying amount in temporary equity per U.S. GAAP, the amount transferred to shareholders' capital differs by $4,554.

d) Convertible debentures

Under Canadian GAAP, the carrying amount of the convertible debentures was bifurcated into equity (the conversion option) and debt whereas under U.S. GAAP, the convertible debentures do not have the features that would require bifurcation. Accordingly, an adjustment to the balance sheets of $4,252 (2009- $4,275) in relation to the Series 3 Convertible Debentures reflects the reclassification of the value attributed to the equity components recorded under Canadian GAAP, to convertible debentures.

Under Canadian GAAP, the accretion of the residual carrying value of the convertible debentures to the face value of the convertible debentures over the life of the instrument is charged to interest expense. Under U.S. GAAP, no such accretion is required if the conversion feature is not required to be bifurcated. This GAAP difference resulted in a reversal of accretion of $426 (2009 - $27) recorded under Canadian GAAP.

24. US GAAP Reconciliation (continued)

e) Financing costs

The Company records financing costs associated with issuance of debt instruments as a reduction to long-term liabilities and convertible debentures under Canadian GAAP. Under U.S. GAAP, such costs are presented in assets as deferred financing costs. Accordingly, the reclassification adjustment reflects a cumulative increase of $840 (2009 - $197) in long-term liabilities and $4,893 (2009 - $5,604) in convertible debentures with a corresponding increase in deferred financing costs of $5,733 (2009 - $5,801).

f) Business combinations and transaction costs

Under Canadian GAAP, the Company recorded $3,014 (2009 - $1,474) of deferred transaction costs in connection with future business acquisitions. Under U.S. GAAP, acquisition-related costs are expensed as incurred.

g) Stock-based compensation

Under U.S. GAAP, the stock-based compensation of $108 (2009 - $nil) is recorded as compensation expense with a balancing entry to additional paid-in-capital. Under Canadian GAAP, the balancing entry is recorded in contributed surplus. An adjustment of $108 (2009 - $nil) reflects the reclassification of stock-based compensation recorded as contributed surplus under Canadian GAAP to additional paid-in capital under U.S. GAAP.

h) Income taxes

The adjustments reflect the future tax impact of the above U.S. GAAP adjustments.

i) Cash flow statement

The consolidated cash flow statement prepared in accordance with Canadian GAAP presents substantially the same information that is required under U.S. GAAP with the exception of deferred transaction costs in connection with future acquisitions of $3,014 (2009 - $1,474) as described in note g) which under U.S. GAAP would be reflected in as cash used in operating activities unlike in Canadian GAAP where it is classified as investing activity. Additionally the Company presents a subtotal in its Canadian GAAP statement of cash from operating activities before change in non-cash operating working capital. This subtotal is not permitted under U.S. GAPP.

j) Adoption of new accounting pronouncements

i) Credit quality:

Effective December 31, 2010, APUC adopted ASU 2010-20, Receivables (Topic 310): Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses, which increases disclosures about credit quality of financing receivables and the allowance for credit losses, and requires disclosures to be made at a greater level of disaggregation. The adoption of this guidance in 2010 has been reflected in the Company's disclosures relating to notes receivable.

ii) Fair value disclosure:

Effective January 1, 2010, APUC adopted ASU 2010-06, Improving Disclosures about Fair Value Measurements which requires more detailed information on fair-value disclosures. The adoption of this guidance in 2010 is reflected in note 22 of the consolidated financial statements.

24. US GAAP Reconciliation (continued)

iii) Variable interest entities:

Effective January 1, 2010, APUC adopted FAS 167: Amendments to FASB Interpretation No. 46(R) which addresses (1) the effects on certain provisions of FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities, as a result of the elimination of the qualifying special-purpose entity concept in FASB Statement No. 166, Accounting for Transfers of Financial Assets, and (2) the application of certain key provisions of Interpretation 46(R), including those in which the accounting and disclosures under the Interpretation do not always provide timely and useful information about an enterprise's involvement in a variable interest entity. The adoption of this standard did not have an impact on the Company's financial statements.

iv) Subsequent events:

In February 2010, the FASB issued ASU No. 2010-09 "Subsequent Events (ASC Topic 855) "Amendments to Certain Recognition and Disclosure Requirements" ("ASU No. 2010-09"). ASU No. 2010-09 requires an entity that is an SEC filer to evaluate subsequent events through the date that the financial statements are issued and removes the requirement for an SEC filer to disclose a date, in both issued and revised financial statements, through which the filer had evaluated subsequent events.

k) Recently issued accounting pronouncements not yet adopted

i) Revenue recognition:

In October 2009, the FASB issued ASU 2009-13, Revenue Recognition (Topic 605): Multiple-Deliverable Revenue Arrangements—a consensus of the FASB Emerging Issues Task Force ("ASU 2009-13"). ASU 2009-13 requires entities to allocate revenue in an arrangement using estimated selling prices of the delivered goods and services based on a selling price hierarchy. The ASU eliminates the residual method of revenue allocation and requires revenue to be allocated using the relative selling price method. ASU 2009-13 should be applied on a prospective basis for revenue arrangements entered into or materially modified in fiscal years beginning on or after June 15, 2010, with early adoption permitted. The Company does not expect adoption of ASU 2009-13 to have a material impact on the Company's consolidated financial statements.

ii) Goodwill:

In December 2010, the FASB issued ASU 2010-28, Intangibles—Goodwill and Other (Topic 350): *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts, a consensus of the FASB Emerging Issues Task Force (Issue No. 10-A*). ASU 2010-28 modifies Step 1 of the goodwill impairment test under ASC Topic 350 for reporting units with zero or negative carrying amounts to require an entity to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. ASU 2010-28 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2010. The Company expects that the adoption of ASU 2010-28 in 2012 will not have a material impact on its consolidated financial statements.

25. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

Corporate Information

Directors

Kenneth Moore, **Chairman** – Managing Partner, NewPoint Capital Partners Inc.
Christopher Ball – Executive Vice-President, Corpfinance International Ltd.
Christopher Huskilson – President & Chief Executive Officer, Emera Inc.
Chris Jarratt – Vice-Chairman, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
George Steeves – Principal, True North Energy

The Management Group

Ian Robertson, Chief Executive Officer
Chris Jarratt, Vice-Chairman
David Bronicheski, Chief Financial Officer

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Registrar and Transfer Agent

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Toronto, Ontario, M5H 4A6

Auditors

KPMG LLP
Toronto, Ontario

Stock Exchange

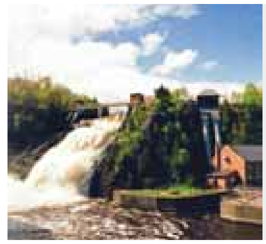
The Toronto Stock Exchange:
AQN, AQN.DB, AQN.DB.A, AQN.DB.B

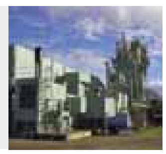
Legal Counsel

Blake, Cassels & Graydon LLP

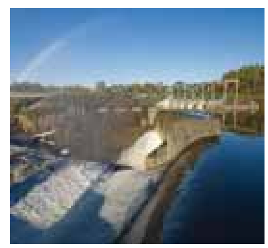
ALGONQUIN
POWER & UTILITIES CORP.

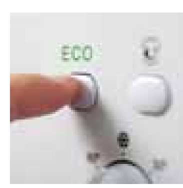
www.algonquinpowerandutilities.com

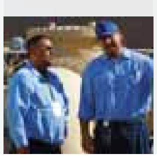


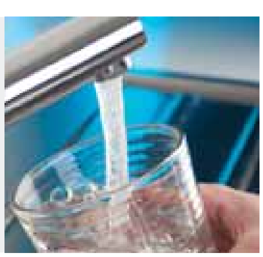


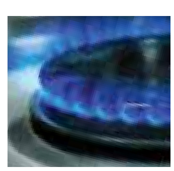
2011 Annual Report











Algonquin Power & Utilities Corp.

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Belleterre, QC

Algonquin Power & Utilities Corp. is a leading power and utility company with a diversified $1.2 billion portfolio of clean renewable electric generation and sustainable rate regulated utility businesses in North America. We are focused on creating shareholder value through the prudent investment in power and utility assets, delivering stable earnings and cash flows coupled with the opportunity for future growth.

Our organization is headed by an experienced executive management team with over 60 years of combined experience in the power and utility sectors. Their experience is evidenced by the successful growth in our asset base from our first generating station investment made 15 years ago to over 70 stable and sustainable power and utility assets generating revenues of over a quarter of a billion dollars today.

Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

2011 Letter to Shareholders

Dear Fellow Shareholders,

Algonquin Power & Utilities Corp. (the "Company") had a very active year in 2011, with our power division, Algonquin Power Co. showing increased energy production throughout the year along with several exciting growth milestones, and our regulated utilities group, Liberty Utilities Co. strategically increasing our regulated utility footprint across the United States.

The Company achieved growth over 2010 earnings and saw attractive shareholder returns through our stable and growing dividend, coupled with capital appreciation which is underpinned by increases in genuine earnings and cashflow arising from the successful execution on our growth strategies.

We have grown our regulated utilities business in the United States and further diversified our power business in Canada during the year, setting the stage for increased stability in earnings going forward as we complete the strategic shift to a growth oriented, dividend paying organization. We have delivered total shareholder return of 73 per cent since our strategic conversion to a corporate structure in late 2009; the result of a clear focus on capital appreciation and dividend growth.

Of course, value accretive growth is not something that simply materializes. We have increased our business development capacities in both our power and utility businesses over the course of the last few years. Our teams are industriously working on sourcing and evaluating the right opportunities for the Company – opportunities that will provide increased per share earnings and cash-flow to the organization, whether in the power or utilities business.

Our development teams delivered many successes in 2011. The power development team commissioned the 26 MW Red Lily wind power generation facility in Saskatchewan, commenced construction of the 17 MW St. Leon wind power project expansion in Manitoba, announced a 75MW wind generation project in Ontario and further diversified the renewable power portfolio with the announcement of our first 10 MW solar project to be constructed near Cornwall, Ontario.

Our utilities development team marked the beginning of the year with the addition of our first electricity distribution business in Lake Tahoe, California and the announcement of an agreement to acquire regulated natural gas distribution assets in Missouri, Illinois and Iowa, further expanding our footprint in the United States. Our team made substantial progress in moving the previously announced acquisition of Granite State Electric Company and EnergyNorth Natural Gas Inc. through the regulatory approval process in New Hampshire. Together, these new acquisitions will bring the total customers served by the Liberty Utilities family to close to 1/3 of a million.

We remain committed in 2012 to deliver continued growth in both our power and utility businesses and our development teams are working on the next projects and acquisitions that you will hear about in the future.

The Strength of our Portfolio

The key to our ongoing business success is the profitable management of our existing portfolio of long-lived, stable power and utility assets. Our asset management and operations teams are mandated to ensure that our existing portfolio delivers on earnings and cashflow expectations. This group of assets will continue to be leveraged to generate additional opportunities in the form of utility system expansion, facility upgrades, equipment refurbishments and repowering of generating facilities, to name a few.

Total Shareholder Return

During 2011, we were very pleased to announce that the Board of Directors approved two dividend increases; an eight per cent increase in March and a seven and a half percent dividend increase in August, bringing the total annual dividend to 28 cents, paid quarterly at the rate of 7 cents per common share. The increase is consistent with the Company's strategy of delivering a compelling total shareholder return comprised of an attractive current dividend yield and capital appreciation driven by earnings and cash flow growth.

Also in 2011, we introduced a Dividend Reinvestment Plan or "DRIP" that allows Canadian holders of common shares a convenient means to acquire additional Company shares through the reinvestment of cash dividends paid on shareholdings. Shares to be delivered under the DRIP are either purchased in the open market or issued at a discount of up to 5% to current market prices. The main advantages of enrolling in the DRIP include the convenience of having cash dividends automatically reinvested instead of receiving cash dividends, and the ability to purchase additional Company shares without having to pay commissions, service charges, or brokerage fees. We are very pleased that the DRIP was well received by our shareholders with, at the end of 2011, 17 per cent of our shares having been enrolled in the DRIP.

As part of our efforts to align our employees' interests with those of the Company, 2011 saw the introduction of an Employee Share Purchase Plan that allows the opportunity for our employees to participate directly in ownership of the Company through the regular purchase of shares. We believe engaged and empowered employees are the cornerstone to running a successful business, and ownership in their Company is a key to our continued future success.

Building on a Strong Partnership

Our relationship with Emera, our largest shareholder, continues to remain strong with both companies fully committed to further capitalizing on the relationship. We have announced a number of acquisitions in which Emera has committed equity financing and we are working with regulatory bodies to ensure approval of their continued investment. Currently, Emera owns approximately twelve per cent of the Company, and under our Strategic Investment Agreement announced in 2011, this ownership position is envisioned to grow to 25 per cent.

Our Focus in 2012

Continuing our strong focus on growth evident over the past few years, we have a full 2012 schedule of power developments, regulatory approvals and integrations of our utility acquisitions. We are comfortable that we have the necessary resources in both our power and utility businesses to successfully achieve the growth milestones ahead of us.

In our power business we have over 350 MW of contracted wind and solar projects in the development pipeline that we are moving through the appropriate permitting processes, with a goal of constructing at least a project a year between now and 2016. Our focus on acquiring and developing long-lived assets with contracted off-take agreements with utility grade counterparties is evident in our average power purchase agreement life growing from 13 years in 2011 to 19 years by 2017.

In our utility business we believe that supporting a number of utility operations with common systems infrastructure will allow us to provide the local, responsive and caring customer service which is the foundation of delivering on our utility investment proposition. We are confident that this customer-centric utility proposition is resonant with our community, customer, employee and regulator stakeholders. We have two pending regulatory proceedings underway and are confident we will bring these to successful close and integrate these new acquisitions into the utility family during 2012. We are pleased to be growing our utility footprint in the United States and supplying safe, reliable and cost effective water, electricity and natural gas services to our growing customer base.

In Summary

Against the backdrop of our recent vigorous growth trajectory, we see 2012 as a year of continuing the momentum by executing on additional initiatives in a measured and paced manner and continuing our investment to develop future opportunities. Our board of directors continues to provide valuable and important governance and oversight of the Company in the review and balancing of the many opportunities that come our way.

Our goals and strategies will guide our actions throughout 2012. We believe our employees are functioning as a well-coordinated team, committed to achieving our goals and ensuring high-levels of corporate stewardship. Successful companies run on the dedication and commitment of their employees. To them, we attribute our success.

We have confidence in our ability to deliver on the value creation opportunities that lie ahead for our Company and look forward to sharing our future success.

Ian Robertson
Chief Executive Officer

Ken Moore
Chairman of the Board of Directors

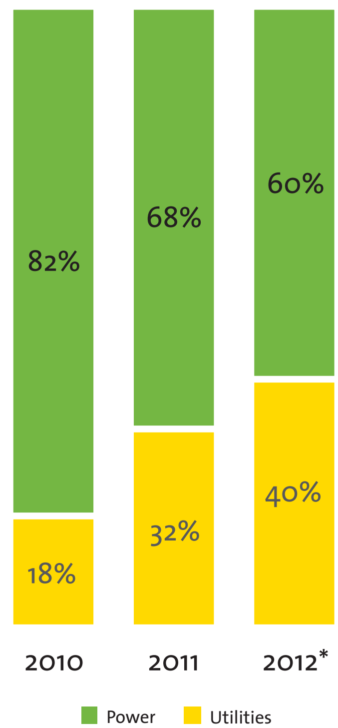
Algonquin
Power & Utilities Corp.

Algonquin Power & Utilities Corp.'s business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the independent power and rate regulated utilities business sectors. The Company is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through dividend growth supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon the company strives to deliver continued growth in its dividend supported by increasing cash flows, earnings and additional investment prospects.

In 2012, our goal is to continue to advance our announced projects and acquisitions to positively impact our cash-flow and earnings per share. We understand that a low risk profile is important to our many stakeholders and we continue to ensure a disciplined approach is taken in financing activities, counterparty relationships, interest rates and commodity exposure to ensure we maximize our growth activities and carefully manage our existing business. Overall, our medium-term plan targets greater than 12 per cent total shareholder return, comprised of earnings and asset growth greater than 15 per cent and growth in earnings per share of at least five per cent. It is positive impacts of our growth activities that allow the Board of Directors the discretion to increase the dividend in a paced and measured way.

We will see a strategic shift in our portfolio this year with the addition of the announced acquisitions into the Liberty Utilities family. In 2009 our portfolio of assets was weighted to the power generation side of the business. Over the past few years we have made several acquisitions in the United States utility sector that will see our company become more balanced between the power and utility sectors, offering further diversification and contributing to the stability of our cash flow profile.

EBITDA Split



* Projected 2012 EBITDA Split

EBITDA = Earnings before interest, taxes, depreciation, and amortization

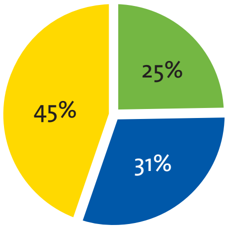
Algonquin Power Co., our electric generation subsidiary, generates and sells electrical energy through a diverse portfolio of clean, renewable power generation facilities across North America. The portfolio includes 41 renewable energy facilities and 9 thermal energy facilities representing more than 450 MW of installed capacity. Growth in this business is delivered through our pipeline of committed power development projects representing over 350MW and $1 billion in investment opportunity.

Rawdon, QC

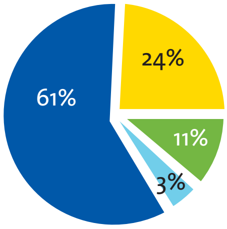
Looking forward in the power business, we have announced well-paced development and acquisition initiatives which will carry us through 2016. This growth further diversifies our business both technologically, with the addition of solar generation to the portfolio, and geographically with our recently announced acquisition of 245MW of United States based wind generation.

Red Lily, SK

An important element to our ongoing business is the profitable management of our existing portfolio of long-lived, stable power assets. An example of this approach to asset management is well demonstrated by our Windsor Locks co-generation facility. In 2011 our team began preliminary plans to re-power the facility, which is a 56 MW natural gas powered electrical and steam energy generating station. The facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to a near-by specialty paper manufacturer. The project entails the installation of a 14 MW combustion gas turbine which is appropriately sized to meet the electrical and steam requirements of the manufacturing facility. This leaves the existing 56 MW turbine available to operate and sell into the New England market when it is commercially profitable to do so. We expect this project to be finished mid-year 2012 and provide a more economical operating model for the plant in the long-term.



2011 Power Portfolio
% earnings contribution



2016 Power Portfolio
% earnings contribution

Our 2012 objectives of continued growth in our power business are in place and our development teams are working on the next projects and acquisitions that you will hear about in the future.

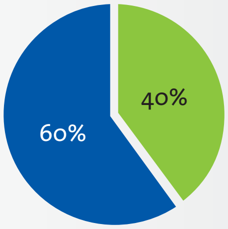
Liberty Utilities

Liberty Utilities Co., our U.S. based utility business, currently provides cost-of-service rate regulated water and electric distribution utility services to more than 120,000 customers primarily located in Arizona, Texas, and California. In 2012, Liberty Utilities Co. will grow further with the acquisition of New Hampshire, Missouri, Iowa and Illinois electric and natural gas distribution utilities serving an additional approximately 213,000 customers. We are committed to expanding this business organically through growth within each utility and through further accretive acquisitions of high quality water, electricity and natural gas distribution assets.

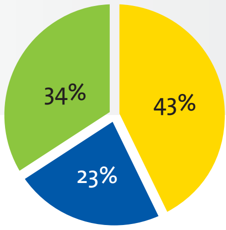
Our utilities business landscape will see significant change over the next few years, with the addition of several new rate regulated electricity and gas distribution assets to the portfolio. The year 2011 was spent seeking regulatory approval on our announced acquisitions and creating detailed plans for the integration of these new assets in the Liberty Utilities operating systems, which will contribute significantly to the growth and diversification of the company through 2016.

Our approach to the ongoing management of our portfolio on the utilities side of the business is well demonstrated through our team's focus on daily operations and system improvements, managing facility rates for our facilities, and planning for growth. As an example, our electricity distribution business in Lake Tahoe, California, serves some of the area ski resorts, providing reliable power for running their businesses. Many of these resorts have major expansion plans underway to add new lifts, terrain and snow making equipment over the next few years. We must keep pace with the growth in the region by upgrading, rebuilding and maintaining our infrastructure in order to continue the reliable service we have become known for in the area. Our team monitors growth in the area and develops carefully considered capital spending plans to ensure our facilities can meet any new capacity that we may be required to deliver.

In 2012 we will continue to target the successful integration of our announced utilities acquisitions while carefully managing the growth within our existing utilities.



2011 Utilities Portfolio
% earnings contribution



2016 Utilities Portfolio
% earnings contribution

ALGONQUIN
Power & Utilities Corp.

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per share and convertible debenture amounts or where otherwise noted)

Management of Algonquin Power & Utilities Corp. ("APUC") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2011. This Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2011 and 2010 prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). See *Change in Accounting Policies* for a discussion on the reasons for this change. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 18, 2012.

Caution concerning forward-looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") and "per share cash provided by operating activities" are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" can be found throughout this MD&A.

Overview and Business Strategy

APUC is incorporated under the Canada Business Corporations Act. APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the independent power and rate regulated utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through dividend growth supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon APUC strives to deliver annualized per share earnings growth of more than 5% and continued growth in its dividend supported by these increasing cash flows, earnings and additional investment prospects

APUC's current quarterly dividend to shareholders is $0.07 per share or $0.28 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Additional increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") and dividend levels shall be reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC currently conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of renewable energy assets and Liberty Utilities Co. ("Liberty Utilities") which owns and operates a portfolio of North American rate regulated utilities.

Algonquin Power Co.

APCo generates and sells electrical energy through a diverse portfolio of renewable power generation and clean thermal power generation facilities across North America. APCo seeks to deliver continuing growth through development of greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of expansion opportunities within APCo's existing portfolio of independent power facilities. As at December 31, 2011, APCo owns or has interests in hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds exchangeable debt securities in a 26 MW wind powered generating station completed in early 2011 in Saskatchewan. All of the electrical output from the wind energy facilities are sold pursuant to long term power purchase agreements ("PPAs") with major utilities which have a weighted average remaining contract life of 20 years. Approximately 80% of the electrical output from the hydroelectric facilities is sold pursuant to long term PPAs with major utilities which have a weighted average remaining contract life of 8.5 years.

APCo owns thermal energy facilities with approximately 120 MW of installed generating capacity and holds ownership interests in three facilities having gross installed capacity of approximately 200 MW. Approximately 67% of the electrical output from the owned thermal facilities is sold pursuant to long term PPAs with major utilities and which have a weighted average remaining contract life of 11 years.

Liberty Utilities Co.

Liberty Utilities provides rate regulated electricity, natural gas and, water distribution and wastewater collection utility services. Liberty Utilities' underlying business strategy is to be a leading provider of safe, high quality and reliable utility services through a nationwide portfolio of moderate sized utilities and deliver stable and predictable earnings to APUC from these utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings through acquisition opportunities which accretively expand its utility business portfolio. The utility businesses owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. As a result of the current and expected growth of Liberty Utilities, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. As a result of this decision, Liberty Utilities businesses operate under two separately managed regions - Liberty Utilities (South) and Liberty Utilities (West).

Liberty Utilities (South) operates in the states of Arizona, Texas, Missouri and Illinois and currently provides regulated water and wastewater utility services to approximately 76,000 customers in those states.

Liberty Utilities (West) operates in the state of California and currently provides regulated local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region of California; on January 1, 2011, in partnership with Emera Inc. ("Emera"), Liberty Utilities (West) acquired the California-based electricity distribution utility and related generation assets (the "California Utility") from NV Energy.

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed to initially deliver electrical and natural gas distribution services to 126,000 customers to be acquired through the acquisition of Granite State Electric Company ("Granite State") and EnergyNorth Natural Gas, Inc., ("EnergyNorth"). Liberty Utilities (Central) will be created initially to manage the delivery of Liberty Utilities gas distribution services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from ATMOS Energy Corporation ("Atmos").

Major Highlights

Corporate Highlights

Dividend Increased to $0.28 for each Common Share

On March 3, 2011, the Board approved an increase in the dividend from $0.24 to $0.26 on an annualized basis. On August 11, 2011, the Board approved a further dividend increase of $0.02 bringing the total dividend to $0.28, paid quarterly at the rate of $0.07 per common share. In approving the increase in dividends, the Board considered the continuing contributions of growth initiatives that began in 2010 and the significant progress made with regards to implementing additional growth initiatives announced in 2011 that have raised the growth profile for APUC's earnings and cash flows. These new growth initiatives, discussed in more detail below, include the acquisition of additional natural gas and electric utilities as well as new wind power generating projects to be built over the next several years.

APUC believes that the increase in dividend is consistent with its stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

Strengthened Liquidity - Issuance of $95.3 million of Common Shares

On October 27, 2011, APUC completed a public offering (the "Offering") of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

The net proceeds of the Offering will be used to fund a portion of the investment related to previously announced growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

Strengthened Balance Sheet - Conversion of Convertible Debentures to Equity

Effective May 16, 2011 ("Redemption Date"), APUC redeemed $2.1 million, all of the remaining issued and outstanding, Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 ("Series 1A Debentures") and issued 430,666 share of APUC. Between January 1, 2011 and the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,976 shares of APUC.

Effective February 24, 2012 ("Series 2A Redemption Date"), APUC redeemed $57.0 million, representing the remaining issued and outstanding, Series 2A Debentures by issuing and delivering 9,836,520 APUC shares. Between January 1, 2012 and the Series 2A Redemption Date, a principal amount of $2.9 million of Series 2A Debentures were converted into 485,998 shares of APUC.

Strategic Investment Agreement with Emera

On April 29, 2011, APUC entered into a strategic investment agreement (the "Strategic Agreement") with Emera which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Agreement builds on the strategic partnership effectively established between the two companies in April 2009.

The Strategic Agreement outlines "areas of pursuit" for each of APUC and Emera. For APUC, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. For Emera, these include investment opportunities related to regulated renewable projects within its service territories and large electric utilities. These “areas of pursuit” are intended to represent investment areas in which there is potential overlap between Algonquin and Emera and are not exhaustive of either company’s business focus and do not limit in any way the activities which either APUC or Emera can undertake. Each of APUC or Emera are free to undertake independently investments within their own “area of pursuit” and outside the other party’s “areas of pursuit”. Under the Strategic Agreement, to the extent either APUC or Emera encounter opportunities which fall within the other’s “areas of pursuit”, they are committed to work with the other party in the development of such investment opportunities.

As an element of the Strategic Agreement, Emera’s allowed common equity interest in APUC will be increased from 15% to 25%. The Strategic Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

Liberty Utilities Highlights

California Utility Acquisition and Senior Debt Financing

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, California Pacific Electric Company (“Calpeco”).

Filing of Approval Application for 100% of California Utility

On April 29, 2011, Emera agreed to sell its 49.999% direct ownership in the California Utility to Liberty Utilities, with closing of such transaction subject to regulatory approval. As consideration, Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012) and the balance of the shares will be issued following completion of the California Utility’s first rate case, expected to be completed in early 2013.

New Hampshire Utility Acquisitions

On December 9th, 2010 Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company (“Granite State”), a regulated electric distribution utility in New Hampshire, and EnergyNorth Natural Gas, Inc. (“EnergyNorth”), a regulated natural gas distribution utility in New Hampshire, both from National Grid USA (“National Grid”), for total consideration of U.S. $285.0 million plus certain working capital adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $250 million.

The closing of the transaction is subject to approval by the New Hampshire Public Utilities Commission (“NHPUC”). Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

Midwest Utility Acquisitions

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the “Midwest Gas Utilities”) located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million.

The closing of the transaction is subject to approval by the Missouri Public Service Commission ("MPSC"), Iowa Utilities Board ("IUB"), and Illinois Commerce Commission ("ICC"). Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Liberty Utilities Credit Facility

On January 19, 2012, Liberty Utilities entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility can be increased to accommodate future working capital needs or other requirements.

Algonquin Power Co. Highlights

Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind power projects in the United States (the "Projects") from Gamesa Corporación Tecnológica, S.A. ("Gamesa"). APCo will contribute U.S. $269 million to partially fund the acquisition of the Projects; tax assisted equity investors will contribute U.S. $360 million. APCo intends to finance its investment with approximately 45% debt and 55% equity. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissioning near the end of 2012.

The Projects consist of four facilities, Minonk (200MW), Senate (150MW), Pocahontas Prairie (80MW) and Sandy Ridge (50MW) located in the states of Illinois, Texas, Iowa and Pennsylvania, respectively. Pocahontas Prairie and Sandy Ridge have recently reached their commercial operation dates ("COD") in February 2012, and Senate and Minonk are in construction with COD anticipated in Q4 2012. Total annual energy production from the four facilities is expected to be 1,644 GW-hrs per year. The Projects are comprised of 240 Gamesa G9X-2.0 MW wind turbines. The Projects each have entered into a 20 year contract with Gamesa to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities.

The Projects have long term, fixed price power sales contracts (the "Power Sales Contracts") with a weighted average life of 11.8 years (Minonk and Sandy Ridge 10 years, Senate 15 years). Approximately 73% of energy revenues would be earned under the Power Sales Contracts. All energy produced in excess of that sold under the Power Sales Contracts, together with ancillary services including capacity and renewable energy credits, will be sold into the energy markets in which the facilities are located.

St. Leon Facility Expansion

On July 18, 2011, APCo entered into a 25-year power purchase agreement with Manitoba Hydro in respect of a 16.5 MW expansion ("St. Leon II") of its existing St. Leon wind energy project located in the Province of Manitoba.

Construction of this project commenced on August 30, 2011. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The total capital cost of the project is expected to be $29.5 million. The project is expected to achieve commercial operation early in the second quarter of 2012 with revenues in the first full year of operating following commissioning expected to be $3.8 million.

Red Lily Wind Project

On February 28, 2011 the 26.4 MW wind generation facility in southeastern Saskatchewan ("Red Lily I") commenced commercial operation under the PPA. APUC's investment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011. APUC earned $1.6 million in interest income and $1.9 million in other payments and fees in 2011. APUC has the option to formally exchange its debt investment for a 75% equity position in the facility in 2016.

New Projects Under Development

As of March 18, 2012, APCo had been awarded or acquired interests in seven major power development projects that significantly expands the company's electrical generation capacity by 350 MW and once completed will increase the company's annual generation production by over 1,200 GWhrs. Each project has a power purchase agreement with a Canadian provincial utility and has a contract length of 20 years or longer.

The following summarizes a number of projects under development and for which PPA's have been awarded since December 2010.

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island	Ontario	75	$230.0	2014	25	247.0
Morse Wind [1]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase	Quebec	24	$70.0	2013	20	86.0
Val Eo	Quebec	24	$70.0	2015	20	66.0
St. Leon II	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

[1]The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011.

A more detailed discussion of these projects is presented within the *APCo: Development Division* business unit analysis.

Senior Unsecured Debentures

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the "Senior Unsecured Debentures"). The net proceeds from the Senior Unsecured Debentures were used to repay the outstanding senior project debt financing related to the St. Leon facility (the "AirSource Senior Debt") and to reduce amounts outstanding under APCo's senior revolving credit facility (the "Facility"). The Senior Unsecured Debentures mature on July 25, 2018, and bear interest at a rate of 5.50% per annum, calculated semi-annually payable on January 25 and July 25 each year, commencing on January 25, 2012.

Credit Facility Renewal

On February 14, 2011 APCo renewed the Facility with its bank syndicate for a three year term with a maturity date of February 14, 2014. The committed credit under the Facility is $120 million.

2011 Annual results from operations

APUC continued to show strong results through 2011. Over the past two years, APUC has focused its efforts on a number of value creation initiatives that, through their completion, are now contributing to the growth evident in APUC revenues, adjusted EBITDA and net earnings. These initiatives include Liberty Utilities' acquisition of the California Utility and successful prosecution of rate cases, APCo's refurbishment of the Energy from Waste facility, acquisition of the Tinker Hydro facility and completion of construction and commissioning of the Red Lily I Wind Farm. As a result, for the year ended December 31, 2011, APUC reported total revenue of $276.6 million as compared to $180.4 million during the same period in 2010, an increase of $96.2 million or 53%.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. (see Non-GAAP Performance Measures). For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million.

Key Selected Annual Financial Information

	Year ended December 31 2011 (millions)	2010 (millions)	2009[5] (millions)
Revenue	**$ 276.6**	$ 180.4	$ 187.3
Adjusted EBITDA [1, 3]	**$ 105.2**	$ 75.1	$ 79.4
Cash provided by Operating Activities	**69.7**	41.4	48.0
Net earnings attributable to Shareholders	**23.4**	18.0	31.3
Adjusted net earnings [1, 3]	**41.6**	22.5	30.5
Dividend declared to Shareholders	**32.4**	22.8	19.3
Per share			
Basic net earnings	**$ 0.20**	$ 0.19	$ 0.39
Adjusted net earnings [1, 3]	**$ 0.36**	$ 0.24	$ 0.38
Diluted net earnings	**$ 0.20**	$ 0.19	$ 0.39
Cash provided by Operating Activities [2, 3]	**$ 0.60**	$ 0.44	$ 0.60
Dividends declared to Shareholders	**$ 0.27**	$ 0.24	$ 0.24
Total Assets	**1,282.6**	1,016.9	1,013.4
Long Term Liabilities[4]	**332.7**	260.0	241.4

[1] APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.
[2] APUC uses per share cash provided by operating activities to enhance assessment and understanding of the performance of APUC.
[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[4] Includes Long-term liabilities and Current portion of long-term liabilities.
[5] Presented using Canadian Generally Accepted Accounting Principles.

The major factors resulting in the increase in APUC revenue in the year ended December 31, 2011 as compared to the corresponding period in 2010, are set out as follows:

	Year ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 180.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	78.1
Liberty Utilities (South) revenue increases primarily due to rate case approvals	8.8
Energy-from-Waste facility	7.6
Effect of hydrology resource compared to comparable period in prior year	6.8
Effect of wind resource compared to comparable period in prior year	3.0
Impact of the weaker U.S. dollar	(5.4)
Tinker Hydro/ Algonquin Energy Services ("AES")	(1.4)
Windsor Locks	(0.9)
All Other	(0.4)
Current Period Revenue	$ 276.6

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the year ended December 31, 2011, APUC experienced an average U.S. exchange rate to each Canadian dollar of approximately U.S. $0.989 as compared to U.S. $1.031 in the same period in 2010. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved average hydrology and wind resources in APCo's Renewable Energy division and improved results from the EFW facility. This increase was partially offset by lower results at Windsor Locks and Tinker facilities, as well as the impact of the weaker U.S. dollar as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million. Basic net earnings per share totalled $0.20 for the year ended December 31, 2011, as compared to $0.19 during the same period in 2010.

For the year ended December 31, 2011, net earnings totalled $27.3 million as compared to $18.4 million during the same period in 2010, an increase of $8.9 million. A number of factors resulted in increased net earnings, including an increase of $32.2 million due to increased earnings from operating facilities, $0.5 million in increased interest and dividend income, $2.2 million related to increased recoveries of income tax expense (see – *2011 Annual Corporate and Other Expenses*) and $0.8 million due to decreased amortization and depreciation expense. These items were partially offset by increased management and administration expenses of $2.6 million, $5.6 million due to increased interest expense, $14.0 million due write downs of intangibles and property, plant and equipment (see - *2011 Annual Corporate and Other Expenses*) and $4.7 million due to increased losses on derivative financial instruments as compared to the same period in 2010.

During the year ended December 31, 2011, cash provided by operating activities totalled $69.7 million or $0.60 per share as compared to cash provided by operating activities of $41.4 million, or $0.44 per share during the same period in 2010, an increase of approximately 36% per share. Cash per share provided by operating activities is a non-GAAP measure. Cash provided by operating activities exceeded dividends declared by 2.1 times during the year ended December 31, 2011 as compared to 1.8 times dividends paid during the same period in 2010. The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2011, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2010.

2011 Fourth quarter results from operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31 2011 (millions)	Three months ended December 31 2010 (millions)
Revenue	**$ 72.1**	$ 48.4
Adjusted EBITDA [1, 3]	**$ 24.3**	$ 20.8
Cash provided by Operating Activities	**4.6**	15.1
Net earnings (loss) attributable to Shareholders	**(8.5)**	15.6
Adjusted net earnings[1, 3]	**6.7**	18.2
Dividends declared to Shareholders	**9.5**	5.7
Per share		
Basic net earnings (loss)	**$ (0.07)**	$ 0.17
Adjusted net earnings[1, 3]	**$ 0.05**	$ 0.19
Diluted net earnings (loss)	**$ (0.07)**	$ 0.17
Cash provided by Operating Activities [2, 3]	**$ 0.03**	$ 0.17
Dividends declared to Shareholders	**$ 0.07**	$ 0.06

[1] APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.
[2] APUC uses per share cash from operating activities to enhance assessment and understanding of the performance of APUC.
[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

For the three months ended December 31, 2011, APUC reported total revenue of $72.1 million as compared to $48.4 million during the same period in 2010, an increase of $23.7 million or 49%. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2011 as compared to the corresponding period in 2010 are set out as follows:

	Three months ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 48.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	20.8
Liberty Utilities (South) revenue increases primarily due to rate case approvals	1.4
Effect of wind resource compared to comparable period in prior year	1.6
Windsor Locks	(0.9)
Impact of the stronger U.S. dollar	0.7
Other	0.1
Current Period Revenue	$ 72.1

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the three months ended December 31, 2011, APUC experienced an average U.S. exchange rate for each Canadian dollar of approximately U.S. $1.023 as compared to U.S. $1.013 in the same period in 2010. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended December 31, 2011 totalled $24.3 million as compared to $20.8 million during the same period in 2010, an increase of $3.5 million or 17%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved wind resource in APCo's Renewable Energy and the impact of the stronger U.S. dollar. This increase was partially offset by lower results at Windsor Locks as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2011, net loss attributable to Shareholders totalled $8.5 million as compared to net earnings of $15.6 million during the same period in 2010, a decrease of $24.2 million. Net loss per share totalled ($0.07) for the three months ended December 31, 2011, as compared to net earnings of$0.17 during the same period in 2010.

For the three months ended December 31, 2011, net loss totalled $8.1 million as compared to net earnings of $15.8 million during the same period in 2010, a decrease of $23.9 million. A number of factors resulted in decreased net earnings for the three months ended December 31, 2011, including $0.5 million related to increased loss on foreign exchange, $1.1 million due to increased interest expense, $9.8 million related to lower recoveries of income tax expense (see *Fourth Quarter Corporate and Other Expenses)*, $14.0 million due to write downs of intangibles and property, plant and equipment (see - *Fourth Quarter Corporate and Other Expenses*) and $3.4 million due to increased losses on derivative financial instruments as compared to the same period in 2010. These items were partially offset by an increase of $2.9 million due to increased earnings from operating facilities, a decrease of $0.3 million due to reduced depreciation and amortization expense, a decrease of $0.3 million due to reduced management and administration expense and a decrease of $1.2 million due to reduced acquisition costs as compared to the same period in 2010.

During the three months ended December 31, 2011, cash provided by operating activities totalled $4.6 million or $0.04 per share as compared to cash provided by operating activities of $15.1 million, or $0.16 per share during the same period in 2010. Cash per share provided by operating activities is a non-GAAP measure. The change in cash provided by operating activities after changes in working capital in the three months ended December 31, 2011, is primarily due to a modest increase in cash from operations, offset by increased interest expense and reduced tax recoveries as compared to the same period in 2010.

Outlook

APCo

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

APCo's energy services business, AES, anticipates that, based on the expected load forecast for its existing contracts, the APCo owned assets will provide almost 50% of the energy required to service its customers in the first quarter of 2012.

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the Independent System Operator New England ("ISO NE") day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

The EFW facility "tip or pay" waste supply agreement with the Region of Peel (the "Region") expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility. For additional information, see *APCo Divisional Outlook – Thermal Energy*.

On January 27, 2012, APCo announced that it plans not to proceed with the previously announced U.S. $83 million minority investment in First Wind Holdings, LLC's ("First Wind") wind energy facilities portfolio in the North East United States. The longer than anticipated regulatory process in Maine and the number of new acquisition and development opportunities announced since April 2011 contributed to the decision not to proceed with the investment.

Liberty Utilities

Liberty Utilities (South) expects continuing modest customer growth throughout its service territories in 2012.

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011.

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the California Public Utilities Commission ("CPUC") seeking, among other things, an increase of 10.0%, or $7.5 million in general rates. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

Algonquin

APCo: Renewable Energy

	Three months ended December 31			Year ended December 31		
	Long Term Average Resource	2011	2010	Long Term Average Resource	2011	2010
Performance (GW-hrs sold)						
Quebec Region	**73.6**	**79.3**	84.1	**279.3**	**304.4**	275.9
Ontario Region	**32.1**	**28.2**	20.2	**134.6**	**121.1**	90.2
Manitoba Region	**105.0**	**119.7**	97.2	**372.0**	**383.8**	343.1
Saskatchewan Region*	**23.3**	**27.7**	-	**66.7**	**68.0**	-
New England Region	**13.4**	**23.7**	13.4	**58.8**	**70.2**	47.9
New York Region	**23.8**	**22.4**	24.4	**90.4**	**92.6**	79.6
Western Region	**12.7**	**11.8**	10.5	**65.9**	**65.5**	59.1
Maritime Region	**35.0**	**40.2**	55.5	**136.9**	**183.0**	148.6
Total	**318.9**	**353.0**	305.3	**1,204.6**	**1,288.6**	1,044.4
Revenue**						
Energy sales		**$ 23,816**	$ 21,867		**$ 87,566**	$ 80,117
Less:						
Cost of Sales – Energy***		**(737)**	(431)		**(3,762)**	(5,047)
Net Energy Sales		**$ 23,079**	$ 21,436		**$ 83,804**	$ 75,070
Other Revenue		**317**	563		**2,291**	2,122
Total Net Revenue		**$ 23,396**	$ 21,999		**$ 86,095**	$ 77,192
Expenses						
Operating expenses		**(7,933)**	(7,013)		**(26,116)**	(24,434)
Interest and Other income		**613**	151		**2,143**	783
Division operating profit (including other income)		**$ 16,076**	$ 15,137		**$ 62,122**	$ 53,541

* Actual production in the Saskatchewan Region reflects production since Red Lily I achieved commercial operation on February 23, 2011. APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility and has an option to acquire a 75% equity interest in the facility in 2016. The long term average resource reflects three and twelve months of production.

** While most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

*** Cost of Sales – Energy consists of energy purchases by AES which is resold to its retail and industrial customers. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

2011 Annual Operating Results

For the year ended December 31, 2011, the Renewable Energy division produced 1,288.6 GWhrs of electricity, as compared to 1,044.4 GWhrs produced in the comparable period, an increase of 23%. The increased generation is primarily due to strong average hydrology in the year as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 72,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 710,000 tons of CO_2 gas was prevented from entering the atmosphere in the year ended December 31, 2011.

During the year ended December 31, 2011, the division generated electricity equal to 107% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the year ended December 31, 2011, the Quebec, New England and Maritimes regions experienced resources significantly higher than long-term averages, producing 9%, 19%, and 34%, respectively, above long-term average resources, while the Manitoba, Saskatchewan, and New York regions experienced resources slightly higher than long-term averages, producing between 2 - 3% above long-term average resources. The Western region experienced resources at long-term averages while the Ontario region experienced resources 10% below long-term averages.

For the year ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $87.6 million, as compared to $80.1 million during the same period in 2010, an increase of $7.5 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares ‘net energy sales’ (energy sales revenue less energy purchases) as a more appropriate measure of the division’s sales results. For the year ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $83.8 million, as compared to $75.1 million during the same period in 2010, an increase of $8.7 million or 12%.

Revenue generated from APCo’s Ontario, Quebec and Western regions increased by $4.8 million due to a 15% overall increase in hydrology and $1.1 million due to an increase in weighted average energy rates, primarily in the Quebec region, of approximately 3% as compared to the same period in 2010. Revenue from APCo’s New England and New York region facilities increased $1.8 million due to increased average hydrology partially offset by $1.1 million due to a decrease in weighted average energy rates of approximately 15%. Revenue from the Manitoba region increased $2.7 million primarily due to a stronger wind resource and $0.4 million due to an increase in weighted average energy rates. Revenue in the Maritime region increased $0.5 million, primarily due to increased customer demand as compared to the same period in 2010. These increases were partially offset by a $1.4 million decrease in revenue at AES primarily due to decreased energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($11.6 million) and merchant sales of production in excess of customer demand and other revenue ($2.3 million). The division reported decreased revenue of $1.0 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

Red Lily I achieved commercial operations effective February 23, 2011. From the commercial operation date through December 31, 2011 Red Lily I produced 68.0 GWhrs of electricity. APCo’s economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily for a direct 75% equity interest in 2016. For the year ended December 31, 2011, APCo earned fees and interest payments from Red Lily I in the total amount of $3.5 million.

For the year ended December 31, 2011, energy purchase costs by AES totalled $3.8 million. During this same period, AES purchased approximately 45.5 GWhrs of energy at market and fixed rates averaging U.S. $84 per MWhr. The Maritime region generated approximately 80% of the load required to service its customers as well as AES’ customers in the year ended December 31, 2011. The division reported decreased energy purchase costs of $0.2 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses excluding energy purchases totalled $26.1 million, as compared to $24.4 million during the same period in 2010, an increase of $1.7 million or 7%. Operating expenses were impacted by $0.9 million related to increased operating costs associated with the Tinker Assets and AES, primarily the result of higher production levels in the Maritime region as compared to the same period in 2010. These increases were partially offset by reduced operating expenses of approximately $0.6 million at the hydroelectric facilities. Operating expenses include costs incurred in the period of $1.9 million associated with the pursuit of various growth and development activities, an increase of $0.7 million as compared to the same period in 2010. In the prior period, APCo recorded a reduction in the development costs due to a reimbursement of $0.9 million in connection with the Red Lily I wind project. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, interest and other income totalled $2.1 million, as compared to $0.8 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo’s earnings from its investment in Red Lily, as discussed above.

For the year ended December 31, 2011, Renewable Energy's operating profit totalled $62.1 million, as compared to $53.5 million during the same period of 2010, representing an increase of $8.6 million or 16%. For the year ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to increased hydrology and wind resources in the Canadian regions.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, the Renewable Energy division produced 353.5 GWhrs of electricity, as compared to 305.3 GWhrs produced in the same period in 2010, an increase of 16%. The increased generation is due to improved average wind generation in the quarter as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 79,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 194,000 tons of CO_2 gas was prevented from entering the atmosphere in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the division generated electricity equal to 111% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the fourth quarter of 2011, the New England region experienced resources significantly higher than long-term averages, producing 175% above long-term average resources, while the Manitoba, Saskatchewan, and Maritimes regions experienced resources higher than long-term averages, producing between 15 - 20% above long-term average resources. The Quebec region experienced resources above long-term averages, producing approximately 10% above long-term average resources. The Ontario, Western and New York regions experienced resources between 5 - 10% below long-term averages.

For the quarter ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $23.8 million, as compared to $21.9 million during the same period in 2010, an increase of $1.9 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $23.1 million, as compared to $21.4 million during the same period in 2010, an increase of $1.7 million or 8%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $0.5 million primarily due to a combination of an increase in weighted average energy rates of approximately 1% and a 5% overall increase in hydrology, primarily in the Ontario region as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $0.6 million primarily due to an increase of approximately 35% in average hydrology, offset by $0.6 million due to a decrease in weighted average energy rates of approximately 30% as compared to the same period in 2010. Revenue in the Maritime region decreased $0.3 million, primarily due to lower merchant sales of excess energy as compared to the same period in 2010. AES experienced a $0.2 million increase in revenue primarily due to increased average energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($2.3 million) and merchant sales of production in excess of customer demand and other revenue ($0.9 million). Revenue from the Manitoba region increased $1.5 million due to an increased wind resource and $0.2 million due to an increase in weighted average energy rates as compared to the same period in 2010. The division reported decreased revenue of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

In the quarter ended December 31, 2011 Red Lily I produced 27.7 GWhr of electricity which was sold to SaskPower. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. For the three months ended December 31, 2011, APCo earned fees and interest payments from Red Lily in the total amount of $0.7 million.

For the quarter ended December 31, 2011, energy purchase costs by AES totalled $0.7 million as compared to $0.4 million during the same period in 2010. During the quarter, AES purchased approximately 13.1 GWhr of energy at market and fixed rates averaging U.S. $54 per MWhr. The Maritime region generated approximately 70% of the load required to service its customers as well as AES's customers in the three months ended December 31, 2011.

For the quarter ended December 31, 2011, operating expenses excluding energy purchases totalled $7.9 million, as compared to $7.0 million during the same period in 2010, an increase of $0.9 million or 13%. Operating expenses were impacted by a $0.3 million increase in operating costs at Canadian hydroelectric facilities, primarily resulting from increased variable operating costs tied to higher production, partially offset by a decrease of $0.3 million related to decreased operating costs associated with the Tinker Assets as compared to the same period in 2010. Operating expenses include costs incurred in the period of $1.2 million associated with the pursuit of various growth and development activities, an increase of $0.5 million as compared to the same period in 2010. The division reported decreased expenses of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest and other income totalled $0.6 million, as compared to $0.2 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the quarter ended December 31, 2011, Renewable Energy's operating profit totalled $16.1 million, as compared to $15.1 million during the same period of 2010, representing an increase of $1.0 million or 7%. For the quarter ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to stronger hydrology and wind generation in both the U.S. and Canadian regions.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

AES anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 35,000 MWhrs of energy to its customers in the first quarter of 2012. AES anticipates that APCo owned assets will provide 43% of the energy required to service its customers in the first quarter of 2012 and that it will need to purchase approximately 20,000 MWhrs of energy from the ISO NE or similar market. AES has in place fixed price financial energy contracts to operationally hedge the price of the customer supply obligations which are not expected to be supplied by APCo owned assets and to minimize the volatility of the energy prices. These contracts in combination with the expected production from APCo owned assets are used to balance the monthly customer load.

APCo: Thermal Energy Division

	Three months ended December 31		Year ended	December 31
	2011	2010	**2011**	2010
Performance (GW-hrs sold)	**126.5**	120.6	**517.0**	465.4
Performance (tonnes of waste processed)	**42,145.0**	43,535.0	**166,825.0**	90,690.0
Performance (steam sales – billions lbs)	**308.4**	315.6	**1,209.4**	1,180.0
Revenue				
Energy/steam sales	**$ 10,582**	$ 11,506	**$ 46,666**	$ 49,860
Less:				
Cost of Sales – Fuel *	**(5,694)**	(5,492)	**(22,896)**	(22,348)
Net Energy/steam Sales Revenue	**$ 4,888**	$ 6,014	**$ 23,770**	$ 27,512
Waste disposal sales	**4,046**	4,164	**16,406**	9,039
Other revenue	**541**	311	**1,352**	1,209
Total net revenue	**$ 9,475**	$ 10,489	**$ 41,528**	$ 37,760
Expenses				
Operating expenses *	**(5,449)**	(5,492)	**(21,589)**	(21,469)
Interest and other income	**(74)**	100	**(6)**	633
Division operating profit (including interest and dividend income)	**$ 3,952**	$ 5,097	**$ 19,933**	$ 16,924

* Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

2011 Annual Operating Results

For the year ended December 31, 2011, the Thermal Energy Division produced 517.0 GW-hrs of energy as compared to 465.4 GW-hrs of energy in the comparable period of 2010. During the year ended December 31, 2011, the business unit's total production increased by 52.4 GWhr from the Windsor Locks facility and 6.1 GWhr from the EFW facility as compared to the same period in 2010. The comparable period includes 2.5 GWhr of production from landfill gas facilities which ceased generating energy and were closed in 2010.

The EFW facility processed 166,825 tonnes of municipal solid waste in 2011 as compared to 90,690 tonnes processed in the same period of 2010. The EFW facility processed waste for a full 12 month period in 2011 as compared to a 6 month period in 2010 when from January to July 2010 the facility was shut down as it underwent an extensive refurbishment. The current level of production resulted in the diversion of approximately 120,000 tonnes of waste from municipal solid waste landfill sites in the year ended December 31, 2011.

During the year ended December 31, 2011, the BCI and Windsor Locks facilities sold approximately 1,200 billion lbs of steam as compared to approximately 1,200 billion lbs of steam in the comparable period of 2010. During the year ended December 31, 2011, operations at the EFW facility generated 508 billion lbs of steam for the BCI facility as compared to 272 billion lbs of steam in the same period in 2010.

For the year ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $46.7 million, as compared to $49.9 million during the same period in 2010, a decrease of $3.2 million, or 6%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $23.8 million, as compared to $27.5 million during the same period in 2010, a decrease of $3.7 million, primarily arising from the weaker U.S. dollar and the power purchase agreement that concluded in April 2010 at the Windsor Locks facility.

The overall decrease in revenue from energy / steam sales was primarily due to a decrease of $5.7 million at the Windsor Locks facility as a result of decreased average energy rates, in part due to the change in operating model of the facility as it came off contract, partially offset by an increase of $4.8 million as a result of increased production, as compared to the prior year. The Sanger facility experienced a net decrease of $0.6 million as a result of decreased energy pricing, in part due to lower average landed price per mmbtu for natural gas, partially offset by $0.2 million as a result of increased production. Energy / steam sales revenue decreased $0.3 million in the period as a result of the closure of the LFG facilities, as compared to the prior year. The decrease in revenue was partially offset by $0.3 million at the BCI and EFW facilities as a result of increased production of energy and steam, as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $1.7 million from operations as a result of the weaker U.S. dollar, as compared to the same period in 2010.

Revenue from waste disposal sales for the year ended December 31, 2011 totalled $16.4 million, as compared to $9.0 million during the same period in 2010. The increase was a result of the EFW facility refurbishment from January to July 2010 in the comparable period of 2010.

For the year ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $22.9 million, as compared with $22.3 million in the same period in 2010, an increase of $0.5 million.[1] The overall natural gas expense at the Windsor Locks facility increased U.S. $1.7 million (10%), primarily the result of a 10% increase in volume of natural gas consumed, as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the year was U.S. $4.84 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of U.S. $0.3 million (5%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the year was U.S. $4.42 per mmbtu. The division reported decreased fuel expenses of $0.8 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $21.6 million, as compared to $21.5 million during the same period in 2010, an increase of $0.1 million. The increase in operating expenses in the year was primarily due to $4.4 million in increased gas, consumables, repair and maintenance and wages at the EFW facility resulting from the outage at the facility in 2010, partially offset by $0.6 million in reduced operating costs at Windsor Locks, $2.0 million at BCI, primarily

[1] APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. Consequently the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other showing decreasing costs, as compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each mmbtu. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed per unit cost for natural gas combined with a consumption of a higher volume of such gas.

the result of reduced natural gas costs due to the EFW facility generating more steam and $0.7 million of reduced operating costs as a result of the closure of the land-fill gas facilities in 2010, as compared to the same period in 2010. Operating expenses in the included costs of $0.4 million associated with the pursuit of various growth and development activities as compared to $0.5 million in the comparable period. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, the Thermal Energy division's operating profit totalled $19.9 million, as compared to $16.9 million during the same period in 2010, representing an increase of $3.0 million or 18%. Operating profit in the Thermal Energy division exceeded expectations for the year ended December 31, 2011 as a result of improved operations at the EFW facility.

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, the business unit produced 126.5 GWhr of energy as compared to 120.6 GWhr of energy in the comparable period of 2010. During the quarter ended December 31, 2011, the business unit's total production increased by 8.0 GWhr from the Windsor Locks facility, partially offset by a decline of 1.6 GWhr from the Sanger facility, as compared to the same period in 2010.

The EFW facility processed 42,145 tonnes of municipal solid waste as compared to 43,535 tonnes of municipal solid waste in the same period of 2010. The current level of production resulted in the diversion of approximately 30,400 tonnes of waste from municipal solid waste landfill sites in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the BCI and Windsor Locks facilities sold 310 billion lbs of steam as compared to 320 billion lbs of steam in the comparable period of 2010. During the quarter ended December 31, 2011, operations at the EFW facility generated 129 billion lbs of steam for the BCI facility as compared to 144 billion lbs of steam in the same period in 2010.

For the quarter ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $10.6 million, as compared to $11.5 million during the same period in 2010, a decrease of $0.9 million, or 8%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $4.9 million, as compared to $6.0 million during the same period in 2010, a decrease of $1.1 million, primarily due to the Windsor Locks facility selling energy into the ISO-NE day-ahead market as compared to in 2010 when facility derived revenues from participating in the Forward Reserve Market. The decision to have the facility not participate in the Forward Reserve Market in 2011 was due to the fact that the facility could earn more selling into the ISO-NE day-ahead market compared to the lower prices offered for participating the Forward Reserve Market in 2011.

The decrease in revenue from energy / steam sales was primarily due to a decrease of $1.3 million at the Windsor Locks facility as a result of decreased energy rates, in part due to a lower average landed price per mmbtu for natural gas and the change in operating model of the facility, partially offset by an increase of $0.7 million at the Windsor Locks facility due to increased production and a net decrease of $0.1 million at the Sanger facility as a result of the change in energy pricing and production as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below.

Revenue from waste disposal sales for the quarter ended December 31, 2011 totalled $4.0 million, as compared to $4.2 million during the same period in 2010.

For the quarter ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $5.7 million, as compared with $5.5 million in the same period in 2010, an increase of $0.2 million. The overall natural gas expense at the Windsor Locks facility increased $0.2 million (5%), primarily the result of a 11% increase in volume of natural gas consumed, partially offset by a 5% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $4.75 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of $0.1 million (10%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu and a 2% decrease in the volume of natural gas consumed as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.03 per mmbtu. The division reported increased fuel costs of $0.1 million as a result of the stronger U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.4 million, as compared to $5.5 million during the same period in 2010, a decrease of $0.1 million.

For the quarter ended December 31, 2011, the Thermal Energy division's operating profit totalled $4.0 million, as compared to $5.1 million during the same period in 2010, representing a decrease of $1.1 million or 22%. Operating profit in the Thermal Energy division met overall expectations for the quarter ended December 31, 2011.

Divisional Outlook – Thermal Energy

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO NE day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

APCo has commenced the repowering project at the Windsor Locks facility and has entered into an agreement with the steam host that extends the steam supply agreement to 2027. See *APCo Development Division – Windsor Locks* for further discussion on the repowering project.

The EFW facility is expected to continue to perform at throughput and operating costs levels in the first quarter of 2012 consistent with the results experienced in 2011. Pursuant to the waste supply agreement with the Region, the EFW facility charges an initial rate for a base 127,900 tonnes per year of acceptable municipal solid waste in a contract year and, once the base throughput levels are exceeded, the facility charges a lower rate for municipal solid waste received in the remainder of the contract year. The facility exceeded the base throughput levels as of the end of 2011 and, as a result, APCo anticipates lower revenue from waste disposal sales of approximately $0.5 million in the first quarter of 2012 as compared to the first quarter of 2011 as the tip fee charged during January and February will be at the lower rate.

The EFW facility "tip or pay" waste supply agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility.

APCo: Development Division

The Development division works to identify, develop and construct new power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. The Development division is focused on projects within North America and is committed to working proactively with all stakeholders, including local communities. APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

The Development division also creates opportunities through accretive acquisitions of operating assets and prospective projects that are at various stages of development.

Current Development Projects

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of Power Purchase Agreements. The projects are as follows:

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind [1]	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$230.0	2014	25	247.0
Morse Wind [3, 4]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$70.0	2013	20	86.0
Val Eo [1]	Quebec	24	$70.0	2015	20	66.0
St. Leon II [1]	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar [1, 2]	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

Notes:
1 PPA signed
2 FIT contract awarded
3 Two 10 MW PPAs; one 5 MW PPA
4 Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

Chaplin Wind

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan.

The project has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $355 million and consist of approximately 77 multi-megawatt wind turbines. The Project is expected to generate first full year EBITDA of $37.5 million. The 25 year power purchase agreement features a rate escalation provision of 0.6% throughout the term of the agreement. The Project will take advantage of a favourable interconnection location by interconnecting with SaskPower's new P1S 230 kV transmission line from Swift Current to Moose Jaw and will be compliant with SaskPower's latest interconnection requirements.

Amherst Island Wind

The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the OPA as part of the second round of the OPA's FIT program.

The FIT contract originally stated that the OPA had the option to terminate the FIT contract prior to the date that the OPA had issued a Notice to Proceed ("NTP") and APCo had paid the incremental security required by the NTP. On August 2, 2011, the Ontario Ministry of Energy directed the OPA to offer FIT contract holders the opportunity to have the OPA's termination rights under the FIT contract waived. APCo exercised this option on August 9, 2011. As required by the waiver, APCo submitted a domestic content plan on October 14, 2011 and provided a statutory declaration regarding equipment supply commitments by November 30, 2011.

The project is currently contemplated to use efficient Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GWhr of electrical energy annually, depending upon the final turbine selection for the project. Total capital costs for the facility are currently estimated to be $230 million. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. Environmental studies and engineering are underway. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 to 18 months.

Morse Wind Project

The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

APCo executed an asset purchase agreement with a local developer ("Kineticor") to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APCo independently. All of the individual projects comprising the Morse Wind Project were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011. Upon SaskPower's approval and execution of the Kineticor PPAs, Kineticor will then assign the PPAs to APCo. All three of the projects are expected to be completed contemporaneously in early 2014.

The total annual energy production for the Morse Wind Project is estimated to be 93,000 MWhr. The capital cost to construct the Morse Wind Project is currently estimated to be $65-$70 million, inclusive of acquisition costs. The first year PPA rate is set at $101.98 per MWhr for the first full year of operations, which APCo expects to occur in 2014, with an annual escalation provision of 2% over the expected 20 year term.

Quebec Community Wind Projects

In 2010, APCo worked with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded power purchase contracts that stipulate the use of ENERCON wind turbines.

Saint-Damase

The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APCo. The first 24 MW phase of the project is expected to be comprised of eight to twelve generators (depending on capacity of the selected wind turbine model), producing approximately 86,000 MWhr annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

The interest of APUC in the project is subject to final negotiations with the municipality but, in any event, will not be less than 50%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing. In July 2011, meetings were conducted with participating landowners in addition to an open house to obtain additional community feedback. All major environmental authorizations are targeted for completion by the end of 2012.

Val-Éo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight generators, producing approximately 66,000 MWhr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interest of APUC in the project is subject to final negotiations with the cooperative but, in any event, will not be less 25%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing with all major authorizations targeted for completion by the end of 2012.

St. Leon II

In July 2011, APCo executed a 25-year power purchase agreement with Manitoba Hydro in respect of St. Leon II (a 16.5 MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba). Construction of this project commenced on August 30, 2011 using 10 Vestas V82 turbines. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The project is expected to achieve commercial operation in the second quarter of 2012. The total capital cost of the project is expected to be $29.5 million.

Cornwall Solar

APCo entered into a share purchase agreement with EffiSolar Energy Corporation ("EffiSolar"), to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the FIT Pipeline have submitted Feed-in-Tariff applications for an additional 100MWac.

The Project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MWhr, resulting in expected initial annual revenues of approximately $6.2 million. The Project contemplates the use of a ground-mounted PV array system, with expected annual generation of approximately 13,400 MWh, enough to provide electricity to approximately 1,000 homes.

Following the completion of all regulatory submissions and approvals, construction of the project is expected to begin in the second half of 2012, with a Commercial Operation Date estimated in early 2013. The Project is being developed on two parcels of leased land totalling approximately 138 acres.

Total capital cost of the project is targeted at approximately $45 million, which amount includes the consideration to be paid for the acquisition of the Project. Funding for the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

Windsor Locks Repowering

The Windsor Locks facility is a 56 MW natural gas powered electrical and steam energy generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to an energy services agreement ("ESA").

APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027, and supports the installation of a new 14 MW Solar Titan combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is in construction with commercial operation expected in July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Windsor Locks facility of approximately U.S. $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO NE market when it is commercially profitable to do so. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("ITC") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

Liberty Utilities
WATER | GAS | ELECTRIC

Liberty Utilities' business strategy is to operate and grow its nationwide portfolio of rate regulated water, natural gas and electric distribution and wastewater collection and treatment utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best-in-class customer care for all utility ratepayers and building constructive regulatory relationships in the jurisdictions in which it operates.

As a result of the current and expected growth, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. This approach will also enhance operational efficiencies and garner greater economies of scale while preserving the customer and regulator focus of the businesses which arises from the independent operations of these regions. As a result of this change Liberty Utilities now has two separately managed regions – Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco).

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed initially to deliver electrical and natural gas distribution services following the acquisition of Granite State and EnergyNorth. A fourth management region, Liberty Utilities (Central), will initially be created to manage the delivery of Liberty Utilities services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from Atmos.

Liberty Utilities is committed to being a leading utility provider of water, natural gas and electric utility services while providing stable and predictable earnings to APUC from its utility operations. Liberty Utilities has presented the division's results in both the reporting currency and its functional currency. Liberty Utilities believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Utilities' functional currency without the impact of foreign exchange.

Liberty Utilities (South)

Liberty Utilities (South) operates in Arizona, Texas, Missouri and Illinois and currently provides rate regulated water and wastewater utility services to approximately 76,000 customers in those states.

	Year ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Number of				
Wastewater connections			**36,750**	35,420
Wastewater treated (millions of gallons)			**2,000**	2,000
Water distribution connections			**38,750**	37,666
Water sold (millions of gallons)			**5,600**	5,500
	U.S. $	U.S. $	**Can $**	Can $
NBV of Assets for regulatory purposes (U.S. $)	**155,763**	155,258		
Revenue				
Wastewater treatment	**$ 23,295**	$ 20,202	**$ 23,031**	$ 20,935
Water distribution	**21,574**	15,877	**21,330**	16,453
Other Revenue	**636**	601	**628**	623
	$ 45,505	$ 36,680	**$ 44,989**	$ 38,011
Expenses				
Operating expenses	**(22,959)**	(21,371)	**(22,720)**	(22,199)
Other income	**482**	154	**488**	149
Divisional operating profit	**$ 23,028**	$ 15,463	**$ 22,757**	$ 15,961

Liberty Utilities (South) is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Utilities (South) has presented the division's results in both the reporting currency and its functional currency. Liberty Utilities (South) believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Utilities (South)'s functional currency without the impact of foreign exchange.

Liberty Utilities (South) reports total connections, inclusive of vacant connections rather than customers. Liberty Utilities (South) had 36,750 wastewater connections as at December 31, 2011, as compared to 35,420 as at December 31, 2010, an increase of 1,330 in the period or 3.8%. Liberty Utilities (South) had 38,750 water distribution connections as at December 31, 2011, as compared to 37,666 as at December 31, 2010, representing an increase of 1,084 in the period or 2.8%. Total connections include approximately 1,800 vacant wastewater connections and 1,400 vacant water distributions connections as at December 31, 2011. Liberty Utilities (South)'s change in water distribution and wastewater treatment customer base during the period is primarily due to the acquisition of two small utilities in Missouri during the last quarter of 2011 and modest growth at Liberty Utilities (South)'s other facilities.

Liberty Utilities (South) has investments in regulatory assets of U.S. $155.8 million across four states as at December 31, 2011, as compared to U.S. $155.3 million as at December 31, 2010.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (South) provided approximately 5.6 billion U.S. gallons of water to its customers, treated approximately 2.0 billion U.S. gallons of wastewater and sold approximately 270 million U.S. gallons of treated effluent.

For the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $45.5 million as compared to U.S. $36.7 million during the same period in 2010, an increase of U.S. $8.8 million or 24%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state regulators over the past two years. Rate cases ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates.

Revenue from water distribution totalled U.S. $21.6 million as compared to U.S. $15.8 million during the same period in 2010, an increase of U.S. $5.7 million or 36%. The annual water distribution revenue was impacted, primarily due to the implementation of rate increases of U.S. $3.9 million at the Litchfield Park Service Company ("LPSCo") facility, U.S. $1.0 million at the Rio Rico facility and U.S. $0.8 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $23.3 million, as compared to U.S. $20.2 million during the same period in 2010, an increase of U.S. $3.1 million or 15%. The annual wastewater treatment revenue was impacted by increased revenue, primarily due to the implementation of rate increases of U.S. $2.8 million at the LPSCo facility and U.S. $0.4 million at the Black Mountain facility, partially offset by lower revenue at the Rio Rico facility of $0.4 million, as compared to the same period in 2010. In addition, revenue increased U.S. $0.4 million at seven wastewater treatment facilities, primarily due to customer increases at the Tall Timbers facility as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses totalled U.S. $23.0 million, as compared to U.S. $21.4 million during the same period in 2010, an increase of U.S. $1.6 million or 7%. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.5 million and U.S. $1.0 million related to increased wages, salary and other operating costs as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $23.0 million as compared to U.S. $15.5 million in the same period in 2010, an increase of U.S. $7.6 million or 49%. Liberty Utilities (South)'s operating profit exceeded expectations for the year ended December 31, 2011 due to increased customer counts and lower than expected power and operating labour costs.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $45.0 million as compared to $38.0 million during the same period in 2010, an increase of $7.0 million. Revenue from wastewater treatment totalled $23.0 million, as compared to $20.9 million during the same period in 2010, an increase of $2.1 million. Revenue from water distribution totalled $21.3 million, as compared to $16.5 million during the same period in 2010, an increase of $4.9 million. Liberty Utilities (South) reported decreased revenue from operations of $1.9 million in 2011 as a result of the weaker U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the year ended December 31, 2011, operating expenses totalled $22.7 million, as compared to $22.2 million during the same period in 2010, an increase of $0.5 million. Liberty Utilities (South) reported lower expenses from operations of $1.2 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $22.8 million as compared to $16.0 million in the same period in 2010, an increase of $6.8 million.

	Three months ended December 31		Three months ended December 31	
	2011	2010	**2011**	2010
Number of				
Wastewater treated (millions of gallons)			**500**	500
Water sold (millions of gallons)			**1,300**	1,400
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Wastewater treatment	**5,855**	5,543	**5,993**	5,649
Water distribution	**5,223**	4,074	**5,347**	4,152
Other Revenue	**123**	205	**126**	208
	$ 11,201	$ 9,822	**$ 11,466**	$ 10,009
Expenses				
Operating expenses	**(5,901)**	(5,264)	**(6,039)**	(5,370)
Other income	**229**	152	**224**	81
Divisional operating profit	**$ 5,529**	$ 4,710	**$ 5,651**	$ 4,720

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, Liberty Utilities (South) provided approximately 1.3 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 35 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $11.2 million as compared to U.S. $9.8 million during the same period in 2010, an increase of U.S. $1.4 million or 14%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state legislators over the past two years.

Revenue from water distribution totalled U.S. $5.2 million, as compared to U.S. $4.1 million during the same period in 2010, an increase of U.S. $1.1 million or 28%. The fourth quarter water distribution revenue increased primarily due to the implementation of rate increases of U.S. $0.6 million at the LPSCo facility, U.S. $0.3 million at the Rio Rico facility and U.S. $0.3 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $5.9 million, as compared to U.S. $5.5 million during the same period in 2010, an increase of U.S. $0.3 million or 6%. The fourth quarter wastewater treatment revenue increased primarily from the implementation of rate increases of U.S. $0.5 million at the LPSCo facility and U.S. $0.2 million at ten wastewater treatment facilities primarily due to increased customers as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses totalled U.S. $5.9 million, as compared to U.S. $5.3 million during the same period in 2010. Overall expenses increased U.S. $0.6 million or 12% as compared to the same period in 2010. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.1 million and U.S. $0.4 million related to wages, salary and other operating costs as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $5.5 million as compared to U.S. $4.7 million in the same period in 2010, an increase of U.S. $0.8 million or 17%. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $11.5 million, as compared to $10.0 million during the same period in 2010. Revenue from wastewater treatment totalled $6.0 million, as compared to $5.6 million during the same period in 2010, an increase of $0.3 million. Revenue from water distribution totalled $5.3 million, as compared to $4.2 million in the same period in 2010, an increase of $1.2 million. Liberty Utilities (South) reported increased revenue from operations of $0.1 million in the fourth quarter of 2011 as a result of the stronger U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the quarter ended December 31, 2011, operating expenses totalled $6.0 million, as compared to $5.4 million during with same period in 2010, an increase of $0.6 million. Liberty Utilities (South) reported lower expenses from operations of $0.4 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $5.7 million as compared to $4.7 million in the same period in 2010, an increase of $0.9 million. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Outlook – Liberty Utilities (South)

Liberty Utilities (South) expects continuing modest customer growth throughout its service territories in 2012.

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011. Liberty Utilities (South) attributes the majority of the revenue increases in the year ended December 31, 2011 to the impact of completed rate cases.

Liberty Utilities (West)

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of approximately U.S. $136.1 million. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility, California Pacific Electric Company ("Calpeco").

The acquisition of the California Utility was completed following receipt of all U.S. state and federal regulatory approvals. Contemporaneously with the closing, Emera exchanged previously announced subscription receipts into 8.532 million APUC common shares at a purchase price of $3.25 per share. The proceeds of the subscription receipts were utilized to fund Liberty Energy's share of the equity in acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured notes. The notes are a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes maturing December 29, 2020 and U.S. $25 million of 5.59% fifteen year notes maturing December 29, 2025.

Liberty Utilities (West) operates in California and currently provides local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region.

	Year ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Number of Customer Accounts				
Residential			41,346	-
Commercial – Small			5,506	-
Commercial – Large			54	-
Total Customer Accounts			**46,906**	
Customer Usage (GWhr)				
Residential			291.2	-
Commercial – Small			174.2	-
Commercial – Large			136.6	-
Total Customer Usage (GWhr)			**602.0**	
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,843**	-		
Revenue				
Utility energy sales and distribution	**$ 78,125**	$ -	**$ 77,368**	$ -
Less:				
Cost of sales – Energy*	**(46,917)**	-	**(46,491)**	
Net utility energy sales	**$ 31,208**	$ -	**$ 30,877**	$ -
Expenses				
Operating expenses	**(16,142)**	-	**(16,019)**	-
Division operating profit**	**$ 15,066**	$ -	**$ 14,858**	$ -

* Cost of Sales – Energy consists of energy purchases. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

** Represents 100% of investment in the California Utility.

As at December 31, 2011, Liberty Utilities (West) holds a 50.001% controlling interest in the California Utility. As the California Utility was acquired on January 1, 2011 there are no comparable results for 2010.

Liberty Utilities reports active connections, exclusive of vacant connections rather than total connections. Liberty Utilities (West) had approximately 41,300 residential electrical customer accounts and 5,550 commercial electrical customer accounts, as at December 31, 2011.

Liberty Utilities (West) has investments in regulatory assets of U.S. $155.8 million in California as at December 31, 2011.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 602,000 MWhr of energy.

For the year ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $78.1 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are ultimately passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net utility energy sales revenue for Liberty Utilities (West) totalled U.S. $31.2 million.

For the year ended December 31, 2011, energy purchases for Liberty Utilities (West) totalled U.S $46.9 million. During the year ended December 31, 2011, the California Utility purchased approximately 602,000 MWhr of energy at rates averaging U.S. $77.9 per MWhr.

For the year ended December 31, 2011, operating expenses, excluding energy purchases, totalled U.S. $16.1 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $15.1 million. Liberty Utilities (West)'s operating profit did not meet expectations for the year ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by lower than budgeted property taxes and higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $77.4 million. For the year ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $30.9 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $46.5 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $16.0 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $14.9 million.

	Three months ended December 31		Three months ended December 31	
	2011	2010	2011	2010
Customer Usage (GWhr)				
Residential			69.4	-
Commercial – Small			50.4	-
Commercial – Large			40.4	-
Total Customer Usage (GWhr)			**160.2**	
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Utility energy sales and distribution	**$ 20,805**	$ -	**$ 21,287**	$ -
Less:				
Cost of Sales – Energy*	**(13,176)**	-	**(13,486)**	
	$ 7,629	$ -	**$ 7,801**	$ -
Expenses				
Operating expenses	**(5,126)**	-	**(5,243)**	-
Division operating profit**	**$ 2,503**	$ -	**$ 2,558**	$ -

* Cost of Sales – Energy consists of energy purchases. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.
** Represents 100% of investment in the California Utility.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 160,100 MWhr of energy.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $20.8 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net utility energy sales revenue totalled U.S. $7.6 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled U.S $13.2 million. During the quarter, the California Utility purchased approximately 160,100 MWhr of energy at rates averaging U.S. $82.3 per MWhr.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses, excluding energy purchases, totalled U.S. $5.1 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $2.5 million. Liberty Utilities (West)'s operating profit did not meet expectations for the three months ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $21.3 million. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $7.8 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $13.5 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $5.2 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $2.6 million.

Outlook – Liberty Utilities (West)

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the CPUC seeking, among other things, an increase of 10.0%, or $7.5 million in general rates, comprised of a $3.3 million increase in vegetation management costs, $13.0 million increase in distribution rates offset by reductions in commodity costs of $8.8 million. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

On April 29, 2011, Liberty Utilities announced it had reached an agreement with Emera to acquire the interest in the California Utility held by Emera. Emera agreed to sell its 49.999% direct ownership in the California Utility, with closing of such transaction subject to regulatory approval. As consideration Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the California Utility ownership transfer (expected in 2012) and the balance of the shares will be issued following completion of the California Utility's first rate case, expected to be completed in early 2013.

Liberty Utilities (East)

On December 9, 2010, Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State, a rate regulated New Hampshire electric utility, and EnergyNorth, a rate regulated New Hampshire natural gas utility for a total purchase price of U.S. $285 million, plus working capital and subject to certain other closing adjustments. The purchase prices for Granite State and EnergyNorth are based on anticipated regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively. Upon completion of the transaction, the results of these utilities will be reported in a newly formed Liberty Utilities (East) division.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire.

The closing of the transaction is subject to approval by the NHPUC. Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

In connection with these acquisitions, Emera has committed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. The issuance of these subscription receipts is subject to regulatory approval.

Financing of these acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Utilities (East) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

Liberty Utilities (Central)

On May 13, 2011, Liberty Utilities (Central) entered into an agreement with Atmos to acquire the gas utilities located in Missouri, Iowa, and Illinois. Total purchase price for the gas utilities is approximately U.S. $124 million, plus working capital and subject to certain other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million, plus working capital and subject to certain other closing adjustments, representing a purchase price multiple of 1.106x. The gas utilities currently provide natural gas local distribution service to approximately 84,000 customers (57,000 in Missouri, 23,000 in Illinois, and 4,000 in Iowa).

The closing of the transaction is subject to approval by the MPSC, the IUB, and the ICC. Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Upon completion of the transaction, the results of these utilities will be reported in the Liberty Utilities (Central) division. It is expected that management responsibility for the rate regulated water utility systems located in

Missouri and currently reported in the results of Liberty Utilities (South) will be transferred to the newly formed Liberty Utilities (Central) following the acquisition of the Atmos assets.

Financing of this acquisition is expected to occur simultaneously with the closing of the transaction. Liberty Utilities (Central) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

APUC: Corporate

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	**2011 (millions)**	2010 (millions)
Corporate and other expenses:				
Administrative expenses and management costs	**4.8**	5.1	**17.5**	14.9
Write down of intangibles and property plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss / (Gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Interest expense	**7.6**	6.5	**30.4**	24.8
Interest, dividend and other Income	**(0.8)**	(1.0)	**(3.0)**	(3.6)
Loss / (Gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)

2011 Annual Corporate and Other Expenses

During the year ended December 31, 2011, management and administrative expenses totalled $17.5 million, as compared to $14.9 million in the same period in 2010. The expense increase in the year ended December 31, 2011 results from additional personnel, increased wages, additional costs required to administer APUC's operations, stock option expense, franchise taxes, a provision related to water lease dues at the Cote St.-Catherine facility and other costs as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1.3 million representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. The carrying value was written down to its fair value less cost to sell resulting in an impairment charge of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the expected sales price. In addition, Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes.

Subsequent to the year end, the Region elected not to extend the existing EFW waste processing contract and is seeking competitive proposals from several waste management companies, including EFW. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and APCo recognized an impairment charge on intangible assets of $13.4 million.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1.8 million representing the difference between the carrying value of the assets and their fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

For the year ended December 31, 2011, interest expense totalled $30.4 million as compared to $24.8 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s senior unsecured notes and APCo's senior unsecured debentures compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures in April 2011, as compared to the same period in 2010.

For the year ended December 31, 2011, interest, dividend and other income totalled $3.0 million, as compared to $3.6 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on interest rate swaps and forward energy purchase contracts during 2011. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $23.0 million was recorded in the year ended December 31, 2011, as compared to a recovery of $20.8 million in the same period in 2010. There are two primary reasons for the income tax recovery for the period ended December 31, 2011. First, in the third quarter of 2011, APUC completed a capital structure project to ensure its operating subsidiaries have a capital structure that is appropriate for its business sector and that uses the functional currency in which it operates. Therefore as part of this process, APUC converted Canadian dollar denominated intercompany notes with a U.S. subsidiary of APCo into U.S. dollar denominated preferred shares resulting in a realized foreign exchange loss for tax purposes and a release of the valuation allowance associated with the unrealized foreign exchange loss accumulated to that point, thereby creating a future tax asset of approximately $15.6 million that is now available as additional tax shelter in future years. Secondly, on October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. Included in future income tax recoveries for the year ended December 31, 2011 is $6.6 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2011 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2011, management and administrative expenses totalled $4.8 million, as compared to $5.1 million in the same period in 2010. The expense decrease in the three months ended December 31, 2011 primarily results from decreased capital taxes, partially offset by the reasons discussed in "*2011 Annual Corporate and Other Expenses*" above as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes. Subsequent to the year end, EFW wrote off the remaining intangible assets associated with the existing waste management and energy contracts with the Region and recognized an impairment charge on intangible assets of $13.4 million. See the discussion in the annual corporate and other expenses section above for details related to this expense.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and the equipment at the Crossroads thermal facility in New Jersey. See the discussion in the annual corporate and other expenses section above for details related to this expense.

For the quarter ended December 31, 2011, interest expense totalled $7.6 million as compared to $6.5 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s long term debt private placement compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures, as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest, dividend and other income totalled $0.8 million, as compared to $1.0 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

Loss (gain) on derivative financial instruments consists of realized and unrealized mark-to-market losses on interest rate swaps and forward energy purchase contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $6.6 million was recorded in the three months ended December 30, 2011, as compared to a recovery of $16.4 million in the same period a year ago. The income tax recovery for the three months ended December 31, 2011 results from those factors discussed in "*2011 Annual Corporate and Other Expenses"* above as compared to the same period in 2010. Included in future income tax recoveries for the three months ended December 31, 2011 is $1.2 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

Non-GAAP Performance Measures

Reconciliation of Adjusted EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense, income tax expense or recoveries, acquisition costs, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended December 31		**Year ended December 31**	
	2011	**2010**	**2011**	**2010**
	(millions)	(millions)	**(millions)**	(millions)
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add (deduct):				
Net earnings attributable to the non controlling interest	**0.5**	0.1	**3.9**	0.4
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)
Interest expense	**7.6**	6.5	**30.4**	24.8
Acquisition Costs	**1.2**	2.3	**3.0**	3.0
Write down of intangibles, property, plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss (gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Loss (gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Depreciation and amortization	**11.6**	12.1	**45.9**	46.6
Adjusted EBITDA	**$ 24.3**	$ 20.8	**$ 105.2**	$ 75.1

For the year ended December 31, 2011, Adjusted EBITDA totalled $105.2 million as compared to $75.1 million, a net increase of $30.1 million or 40% as compared to the same period in 2010. For the quarter ended December 31, 2011, Adjusted EBITDA totalled $24.3 million as compared to $20.8 million, a net increase of $3.5 million or 17% as compared to the same period in 2010.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

	Three months ended December 31, 2011 (millions)	Year ended December 31, 2011 (millions)
Comparative Prior Period Adjusted EBITDA	$ 20.8	$ 75.1
Significant Changes:		
Acquisition of the California Utility	2.5	15.1
EFW facility	(0.4)	5.2
Liberty Utilities (South) revenue increases primarily due to rate case approvals	0.7	7.2
Hydro Renewable due to improved hydrology (reduced hydrology in Q4)	(0.5)	6.1
St. Leon - primarily due to an increased wind resource	1.6	3.0
Administration and management costs	0.3	(2.6)
Lower results from the weaker U.S. dollar (stronger in Q4)	1.2	(1.7)
Tinker Hydro / AES primarily due to lower energy demand	(0.2)	(1.0)
Windsor Locks – change in operating model	(0.4)	(1.9)
Other	(1.3)	0.7
Current Period Adjusted EBITDA	**$ 24.3**	**$ 105.2**

Reconciliation of adjusted net earnings to net earnings

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. APUC uses adjusted net earnings to assess its performance without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs and write down of intangibles and property, plant and equipment as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended December 31, 2011		Year ended December 31, 2011	
	2011	2010	2011	2010
	(millions)	(millions)	(millions)	(millions)
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add:				
Loss (gain) on derivative financial instruments, net of tax	**1.0**	(1.2)	**3.9**	0.7
Loss (gain) on foreign exchange, net of tax	**0.4**	(0.1)	**(0.7)**	(0.5)
Write down of intangibles, property, plant and equipment	**13.1**	2.5	**13.2**	2.5
Acquisition costs, net of tax	**0.7**	1.4	**1.8**	1.8
Adjusted net earnings	**$ 6.7**	$ 18.2	**$ 41.6**	$ 22.5
Adjusted net earnings per share	**$ 0.05**	$ 0.19	**$ 0.36**	$ 0.24

For the year ended December 31, 2011, adjusted net earnings totalled $41.6 million as compared to adjusted net earnings of $22.5 million, an increase of $19.1 million as compared to the same period in 2010. The increase in adjusted net earnings in the year ended December 31, 2011 is primarily due to increased earnings from operations, partially offset by increased interest and administrative expenses and lower recoveries of deferred taxes as compared to the same period in 2010.

For the three months ended December 31, 2011, adjusted net earnings totalled $6.7 million as compared to $18.2 million, a decrease of $11.5 million as compared to the same period in 2010. The decrease in adjusted net earnings in the three months ended December 31, 2011 is primarily due to increased interest and administrative expenses and reduced recoveries of deferred taxes, partially offset by increased earnings from operations as compared to the same period in 2010.

Summary of Property, Plant and Equipment Expenditures

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	2011 (millions)	2010 (millions)
APCo				
Renewable Energy Division				
Capital expenditures	**$ 6.7**	$ 1.0	**$ 25.6**	$ 2.3
Acquisition of operating entities	**-**	-	**-**	40.3
Total	**$ 6.7**	$ 1.0	**$ 25.6**	$ 42.6
Thermal Energy Division				
Capital expenditures	**$ 4.5**	$ 0.5	$ 13.6	$ 11.6
Total	**$ 4.5**	$ 0.5	**$ 13.6**	$ 11.6
LIBERTY UTILITIES				
South				
Capital Investment in regulatory assets	**$ 1.5**	$ 4.5	**$ 10.9**	$ 6.6
Acquisition of operating entities	**0.4**	-	**1.3**	2.1
Total	**$ 1.9**	$ 4.5	**$ 12.2**	$ 8.7
West				
Capital Investment in regulatory assets	**$ 4.9**	$ -	**$ 10.3**	$ -
Acquisition of operating entities	**1.4**	3.1	**98.7**	3.1
Total	**$ 6.3**	$ 3.1	**$ 109.0**	$ 3.1
Consolidated				
Total APCo				
Capital expenditures	$ 11.2	$ 1.5	**$ 39.2**	$ 13.9
Acquisition of operating entities	-	-	**-**	40.3
Total Liberty Utilities				
Capital investment in regulatory assets	$ 6.4	4.5	**$ 21.2**	6.6
Acquisition of operating entities	1.8	3.1	**100.0**	5.2
Corporate	0.1	0.1	**0.4**	0.2
Total	**$ 19.5**	$ 9.2	**$ 160.8**	$ 66.2

APUC's consolidated capital expenditures in the year ended December 31, 2011 increased as compared to the same period in 2010 primarily due to the acquisition of the California Utility, the start of the construction of St. Leon II and the Windsor Locks repowering project.

Property, plant and equipment expenditures for 2012 are anticipated to be between $60 million and $70 million, including approximately $14.0 million related to ongoing requirements by Liberty Utilities (South), $11.0 million at Liberty Utilities (West) related to the California Utility, $15.5 million related to the APCo Thermal division, primarily related to the Windsor Locks repowering and major maintenance at the Sanger facility, and $18.5 million related to the APCo Renewable Energy division, primarily related to the St. Leon II expansion and a major project at the Tinker facility.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2011 Annual Property Plant and Equipment Expenditures

During the year ended December 31, 2011, APCo incurred net capital expenditures of $39.2 million, as compared to $13.9 million during the comparable period in 2010. APCo also invested $40.3 million to acquire operating assets/entities during the comparable period in 2010.

During the year ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $25.6 million, as compared to $2.3 million in the comparable period in 2010. The St. Leon II development and the turbine overhaul project at the Tinker facility were the major individual projects initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets in 2010 relate to the Tinker Assets located in New Brunswick and Maine. The APCo Thermal Energy division's net capital expenditures were $13.6 million, as compared to $11.6 million in the comparable period in 2010. The major expenditures in the year primarily relates to the Windsor Locks repowering project and investments at the Sanger facility. In the comparable period, the capital expenditures primarily relate to the EFW facility where major capital maintenance was underway.

During the year ended December 31, 2011, Liberty Utilities invested $21.2 million in regulatory assets, as compared to $6.6 million during the comparable period in 2010. These investments comprise of $10.9 million at Liberty Utilities (South) and $10.3 million at Liberty Utilities (West). Liberty Utilities also invested $100.0 million to acquire operating assets/entities, primarily related to Liberty Utilities (West)'s investment of $98.7 million to acquire the California Utility in 2011.

2011 Fourth Quarter Property Plant and Equipment Expenditures

During the quarter ended December 31, 2011, APCo incurred net capital expenditures of $11.2 million, as compared to $1.5 million during the comparable period in 2010.

During the quarter ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $6.7 million, as compared to $1.0 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the St. Leon II development and the turbine overhaul project at the Tinker facility. The APCo Thermal Energy division's net capital expenditures were $4.5 million, as compared to $0.5 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the Windsor Locks repowering project and investments at the Sanger facility.

During the quarter ended December 31, 2011, Liberty Utilities invested $6.4 million, as compared to $4.5 million during the comparable period in 2010. These investments comprise of $1.5 million at Liberty Utilities (South) and $4.9 million at Liberty Utilities (West). During the quarter, Liberty Utilities (West) recorded an adjustment to the purchase price of the California Utility which reduced the purchase price by $1.4 million.

Dam Safety Legislation

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. All eleven dam safety evaluations have now been completed. Out of these, nine remedial plans have been submitted to the Quebec government and two are undergoing options analysis by APCo. The nine remedial plans have been accepted by the Quebec government and one is still being reviewed.

APCo has spent approximately $1.5 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APCo currently estimates further capital expenditures of approximately $16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

	Total	2012	2013	2014	2015
Estimated future Bill C-93 Capital Expenditures	**16,900**	1,100	5,300	7,700	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities.

- The dam safety evaluation for the Mont Laurier facility was completed in 2008 and APCo's proposed remediation plan has now been accepted by the Quebec government. APCo has been performing engineering and permitting since 2010 and received the Certificate of Authorization from the Quebec government in November 2011. APCo anticipates completing the on-site remediation work in 2012.
- In respect of the Donnacona facility, APCo completed the dam safety evaluation in 2007 and has been investigating alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates. APCo anticipates completing the engineering in 2012 and performing the remedial work in 2013 and 2014.

- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCO will review the results of the condition assessment and finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo has been corresponding with the Quebec government and other stakeholders about these options since 2007. APCo anticipates completion of any required work on these dams by 2015.
- The dam remediation work related to Chute Ford will be completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013. No dam remediation work is required at the Arthurville, Hydraska, and Ste-Brigitte facilities.
- The dam remediation work related to the Rawdon facility was completed in 2011.

In addition to the C-93 related dam remediation work, APCo has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

LIQUIDITY AND CAPITAL RESERVES

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2011 under the Facility:

	2011 Q4 (millions)	2011 Q3 (millions)	2011 Q2 (millions)	2011 Q1 (millions)	2010 Q4 * (millions)
Committed and available Facility	$ 120.0	$ 120.0	$ 142.0	$ 142.0	$ 142.0
Funds Drawn on Facility	-	(12.0)	(70.0)	(65.0)	(64.5)
Letters of Credit issued	(39.6)	(40.1)	(32.5)	(32.9)	(33.1)
Remaining available Facility	**$ 80.4**	**$ 67.9**	**$ 39.5**	**$ 44.1**	**$ 44.4**
Cash on Hand	72.9	15.5	8.7	2.5	**4.7**
Total liquidity and capital reserves	**$ 153.3**	**$ 83.4**	**$ 48.2**	**$ 46.6**	**$ 49.1**

* Reflects availability as at December 31, 2010, under the terms of a three year Facility renewed subsequent to December 31, 2010, having a maturity of February 14, 2014.

During the first quarter, APCo concluded negotiations with its bank syndicate on the renewal of the Facility for a three year term with a maturity date of February 14, 2014. Algonquin also reduced the total of the Facility to $120 million following the completion of the Senior Unsecured Debenture offering of APCo in July 2011. As at December 31, 2011, no amounts had been drawn on the Facility as compared to $64.5 million as at December 31, 2010. In addition to amounts actually drawn, there were $39.6 million in letters of credit outstanding as at September 30, 2011. APCo had $80.4 million of committed and available bank facilities remaining and $72.9 million of cash resulting in $153.3 million of total liquidity and capital reserves.

On July 25, 2011, APCo completed the Senior Unsecured Debenture offering of $135 million, the net proceeds of which were used to repay the Airsource senior debt financing having a principal amount outstanding of $67.8 million with the balance being used to reduce amounts outstanding on the Facility.

On October 27, 2011, APUC completed an equity offering of $85.3 million, a portion of the net proceeds of which have been used to repay the outstanding balance on the Facility. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

On January 19, 2012, Liberty Utilities announced that it had entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility includes provisions which allow the available credit to be increased to accommodate future working capital needs or other requirements.

APUC intends to use its liquidity and capital reserves to fund announced capital expansion projects in APCo and to partially fund announced share acquisitions in Liberty Utilities.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of December 31, 2011 is shown below:

	Total (millions)	Due less than 1 year (millions)	Due 1 to 3 years (millions)	Due 4 to 5 years (millions)	Due after 5 years (millions)
Long-term debt obligations[1]	$ 332.7	$ 1.6	$ 3.7	$ 16.5	$ 310.9
Convertible debentures[2]	$ 122.3	-	-	59.7	62.6
Interest on long-term debt obligations	$ 227.9	25.6	40.2	37.3	124.8
Long term service agreements	$ 94.4	4.6	8.2	8.6	73.0
Purchased power	$ 227.5	45.1	91.5	90.9	-
Accounts payable/purchase obligations	$ 57.3	57.3	-	-	-
Capital Projects	$ 7.9	7.9	-	-	-
Energy forward purchase contract	$ 1.2	0.8	0.4	-	-
Interest rate swap	$ 6.9	2.1	3.7	1.1	-
Lease obligations	$ 2.7	1.2	1.2	0.3	-
Other obligations	$ 9.8	1.1	0.5	0.5	7.7
Total obligations	$ 1,090.6	$ 147.3	$ 149.4	$ 214.9	$ 579.0

[1] Long term obligations include regular payments related to long term debt and other obligations.

[2] Convertible debentures include the Series 2A Debentures which were redeemed for equity effective February 24, 2012.

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2011, APUC had 136,122,780 issued and outstanding shares. Following the Series 2A Redemption, APUC had 146,741,635 shares outstanding.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2011, APUC does not have any issued and outstanding preferred shares.

As at December 31, 2011, APUC had issued to Emera a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the Granite State and EnergyNorth transactions at a purchase price of $5.00. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost to acquire Granite State and EnergyNorth.

On April 29, 2011, APUC agreed to issue to Emera 8.2 million shares with regards to the acquisition by Liberty Utilities of Emera's 49.999% direct ownership in the California Utility. The approval on the ownership transfer is expected in early 2012. The payment of shares is to be made in two tranches with approximately half of the shares being issued following regulatory approval of the ownership transfer and the balance of the shares being issued following completion of the California Utility's first rate case which is expected to be completed in 2012.

On April 30, 2011, APUC committed to issuance to Emera of a treasury subscription of subscription receipts convertible into approximately 6.9 million APUC common shares upon closing of the transaction related to the acquisition of an interest in a portfolio of 370MW wind projects. This treasury subscription was terminated when APCo announced on January 27, 2012 that it no longer intended to proceed with the First Wind acquisition.

On April 7th, 2011, APUC provided the holders of its Series 1A Debentures with notice of its intention to redeem for equity, all of the issued and outstanding Series 1A Debentures. Prior to the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On the Redemption Date, APUC issued and delivered 430,666 APUC shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of APUC shares on the Redemption Date. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

Subsequent to December 31, 2011, on January 20, 2012, APUC provided the holders of its Series 2A 6.35% convertible unsecured subordinated debentures due November 30, 2016 ("Series 2A Debentures") notice of its intention to redeem for equity, effective February 24, 2012 ("Series 2A Redemption Date"), all of the issued and outstanding Debentures. Prior to the Series 2A Redemption Date, a principal amount of $2,916 of Series 2A Debentures were converted into 485,998 shares of APUC.

On the Series 2A Redemption Date, APUC issued and delivered 9,836,520 APUC shares to the remaining holders of Series 2A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures of $57,041, by 95% of the current market price of APUC shares on the Series 2A Redemption Date. As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

On December 2, 2009, APUC issued 63,250 convertible unsecured debentures at a price of $1,000 for each debenture maturing on June 30, 2017 (“Series 3 Debentures”). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures’ maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional shares.

On December 31, 2011, there were 62,571 Series 3 Debentures outstanding with a face value of $62,571.

During the three months ended December 31, 2011, a principal amount of $129 Series 3 Debentures were converted into 30,710 shares APUC. During the year ended December 31, 2011, a principal amount of $334 Series 3 Debentures were converted into 79,517 shares APUC. Subsequent to the end of the quarter, $66 Series 3 Debentures were converted to 15,711 shares.

SHARE BASED COMPENSATION PLANS

For the year ended December 31, 2011, APUC recorded $0.7 million (2010 - $0.1 million) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1.2 million and $0.1 million respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

STOCK OPTION PLAN

On June 23, 2010, APUC’s shareholders approved a stock option plan (the “Plan”) that permits the grant of share options to key officers, directors, employees and selected service providers. On June 21, 2011, APUC’s shareholders approved amendments to the Plan to limit non-employee director participation in the Plan and to require shareholder approval to make further amendments to the plan with respect to a number of items as more fully described in the management information circular for the 2011 annual and special meeting of shareholders.

During the year ended December 31, 2010, 1,160,204 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $4.05. One-third of the options vest on each of January 1, 2011, 2012 and 2013. During the year ended December 31, 2011, the Board approved the following grant of options:

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;

- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.68.

Subsequent to year end on March 14, 2012, 1,194,606 options were granted which allow for the purchase of common shares at a price of $6.22.

All options are issued at the market price of the underlying common share at the date of grant. In each case, one-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

During the year ended December 31, 2011, no options were exercised. As at December 31, 2011, APUC had 2,487,104 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

As at December 31, 2011, 386,735 options with an intrinsic value of $917 are exercisable. No share options were exercised in 2011 or 2010. The intrinsic value of the 2,487,104 options as at December 31, 2011 was $4,134.

PERFORMANCE SHARE UNITS

In October 2011, APUC issued 28,370 performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. At the end of the three-year performance periods, the number of shares vested can range from 0% to 144% of the number of PSUs granted. Dividends accumulate during vesting period and are converted to PSUs based on the market value of the shares on that date. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

DIRECTORS DEFERRED SHARE UNITS

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one APUC common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period.

As at December 31, 2011, no DSUs had been issued.

EMPLOYEE SHARE PURCHASE PLAN

In September 2011, APUC approved an employee share purchase plan ("ESPP"). Eligible employees may have a portion of their earnings withheld to be used to purchase common shares of APUC. APUC will match up to 20% of an employee's contribution amount for the first $5,000 contributed annually and 10% of an employee's contribution amount for contributions over $5,000 and up to $10,000 annually. Shares purchased through the APUC match portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at December 31, 2011, a total of 7,176 shares had been issued under the ESPP. For the three and twelve month period ended December 31, 2011, APUC recorded $9 in compensation expense.

DIVIDEND REINVESTMENT PLAN

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the “Reinvestment Plan”) which will be offered to registered holders of shares (“Shareholders”) of APUC.

The purpose of the Reinvestment Plan is to enable Shareholders to invest all cash dividends on Shares in additional shares of APUC (“Plan Shares”). All such Plan Shares will be, at APUC’s election, either (i) Shares purchased on the open market through the facilities of the TSX (“Market Purchase”) or (ii) newly issued Shares purchased from APUC (“Treasury Purchase”).

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the Agent for all Plan Shares purchased in respect of a Dividend Payment Date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Shares of APUC on TSX for the five (5) trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC’s election. No commissions, service charges or brokerage fees are payable by Shareholders in connection with the Reinvestment Plan.

As at December 31, 2011, 23.6 million common shares had been registered with the Reinvestment Plan.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

APUC’s objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

- Certain executives of APUC are shareholders of Algonquin Power Management Inc. (APMI), the former manager of APCo. A member of the Board of Directors of APUC is an executive at Emera.

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and twelve months ended December 31, 2011 were $82 and $327, respectively (2010 - $82 and $327). Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.

- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC’s business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the three and twelve months ended December 31, 2011, APUC incurred costs in connection with the use of the aircraft of $103 and $453, respectively (2010 - $60 and $430) and amortization expense related to the advance against expense reimbursements of $69 and $274, respectively (2010 - $13 and $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a five year period commencing two years after the commercial operation date of the facility of June 17, 2006, increasing by 2.5% every 5 years to a maximum of 10%. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $106 and $314 for the three and twelve months ended December 31, 2011 (2010 - $77 and $266).
- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.
- Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") an entity where Senior Executives hold equity interests. APUC and APS had agreed to provide some transition services to each other until December 31, 2011. This agreement has been extended for an additional year in relation to one of the hydroelectric generating facilities. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.
- As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.
- A contract with a subsidiary of Emera to purchase energy on ISO NE and provide scheduling services on ISO NE was included as part of the acquisition of AES associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of AES. In this capacity, APUC paid a subsidiary of Emera an amount of $0 (2010 - $0 and $1,368) during the three and twelve months ended December 31, 2011 which was included as an operating expense on the consolidated statement of operations.
- In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2011 APUC paid U.S. $73 and $260 (2010 - $64 and $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.
- On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). During the three and twelve months ended December 31, 2011, AES sold electricity to MPS amounting to $1,263 and $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.
- In 2008, APUC entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and APUC issued equity to the Highground shareholders and CJIG, in exchange for $26.2 million cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as

an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

- As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of the costs related to the California Utility.
- Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.
- APUC believes that the transactions noted above were in accordance with normal commercial terms. The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Business Associations with APMI and Senior Executives.

There have been a number of business relationships between Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates (collectively the "Parties") and APUC. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. In 2011, the Board conducted a process to review all of the remaining business associations with the Parties in order to reduce, streamline and simplify these relationships. The Board formed a special committee and engaged independent consultants to assist with this process.

The co-owned assets and remaining business associations as at December 31, 2011 are listed below. Subsequent to December 31, 2011, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "Agreement"). A more detailed description of the Agreement has been set out below in S*ettlement of Other Business Associations*.

i) *Rattlebrook hydroelectric generating facility*

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 27.5% by Senior Executives and the remaining percentage by third parties. This relationship was addressed pursuant to the Agreement. See S*ettlement of Other Business Associations* below for more details.

ii) *St. Leon wind power generating facility*

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives. APUC and the Class B unit holders have simplified the relationship by amalgamating the previous partnership agreement and two amending agreements into an amended and restated agreement. In addition, APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

iii) *Brampton Cogeneration Inc.*

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $100 in relation to the development of this project. In 2008, APUC accrued $100 as an estimate of the final fee owed to APMI. This relationship and corresponding liability was addressed pursuant to the Agreement.

iv) Long Sault Rapids hydroelectric generating facility

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the equity cash flows commencing in 2014. This relationship was addressed pursuant to the Agreement.

v) Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2011, $279 of the advance remained. The Board has undertaken an independent review of the relationship and believes that continuing the original arrangement is beneficial to the company. The current arrangement is expected to end in approximately 2016 when the advance will be fully utilized.

vi) Office lease

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The original lease was due to expire in December 31, 2012. Effective April 1, 2011, a subsidiary of APUC leased its head office facilities from a third party in a new stand alone building immediately adjacent to APUC's head office for a term of 5 years ending December 31, 2015 with an additional 5 year renewal option. APUC has amended its lease at its existing premises to be co-terminus with its subsidiary's new lease. The majority of terms in the amended lease are identical. Based on a review of the real estate leasing market in the fall of 2010, APUC believes the amended lease is on terms equivalent to fair market value for prime office space of similar size and quality.

vii) Operations services

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by an affiliate of APMI. APUC and the APMI affiliate had agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit. APUC agreed to provide supervisory management on a cost recovery basis for one of the facilities until December 31, 2012 to provide sufficient time for APMI to make alternative arrangements to manage the facility.

viii) Sanger construction management

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI. This liability was settled pursuant to the Agreement.

ix) Clean Power Income Fund

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund ("Clean Power") to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of December 31, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet. This liability was settled pursuant to the Agreement.

x) Red Lily I

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. APUC has acquired APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility. This liability was settled pursuant to the Agreement.

xi) Trafalgar

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar was previously awarded a U.S. $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was reached in 2004 between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal fees, third party costs and other liabilities with the proceeds from the lawsuits being shared after reimbursement of legal fees, third party costs and other liabilities. The Board has determined that any proceeds from the lawsuit will be shared between APMI and APUC proportionally to the quantum of such costs funded by each party. The Second Circuit Court of Appeals dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

Settlement of Other Business Associations.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including Sanger repowering project, the offer to acquire Clean Power and the development of the Red Lily I wind project.

The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the Rattlebrook and Long Sault Rapids facilities, provide a valuation of these assets and to provide advice to APUC in respect thereof.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, any credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 55% of EBITDA in 2012 and 65% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $5.4 million ($0.05 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

Market price risk

The majority of APCo's electricity generating facilities sell their output pursuant to long-term PPAs. However, certain of APCo's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each $10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of $1.0 million on an annualized basis.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables, net receivable and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APUC does not believe this risk to be significant as approximately 82% of APCo Renewable Energy division's revenue, approximately 48% of APCo Thermal Energy division's revenue, and over 68% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	23,200	26%
Manitoba Hydro	AA	22,400	25%
Ontario Electricity Financial Corporation	A+	11,000	12%
MPS**	BBB+	6,600	7%
TransAlta Corp – Dickson Dam	BBB	4,000	5%
Public Service Company of New Hampshire	BBB	3,200	4%
National Grid	A-	3,000	3%
Total		**$ 73,400**	**82%**
Thermal Energy Division			
Regional Municipality of Peel	AAA	16,400	25%
Pacific Gas and Electric Company	BBB+	14,600	23%
Total		**$ 31,000**	**48%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2012.
** MPS is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. In this regard, the credit risk related to Liberty Utilities (South) accounts receivable balances of U.S. $5.1 million is spread over approximately 76,000 customers, resulting in an average outstanding balance of approximately $70.00 per customer. Liberty Utilities (West) has accounts receivable balances of U.S. $14.2 million with over 50% of revenue generated by residential customers.

Interest rate risk

APCo has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Facility has no amounts outstanding as at December 31, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

- APCo's project debt at the St. Leon facility had a balance of $67.8 million as at June 30, 2011. The outstanding balance was repaid during the quarter ended September 30, 2011 using proceeds from the Senior Unsecured Debenture offering. Accordingly there is no further interest rate risk associated with this debt facility.

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2011. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.

- APCo's project debt at Long Sault, Chute Ford and its $135 million senior unsecured debentures bear fixed rates of interest and are not subject to interest rate risk.

Liberty Utilities (South)'s project debt at the Litchfield and Bella Vista Facilities are subject to a fixed rate of interest and thus are not subject to interest rate risk. Liberty Utilities (South)'s U.S. $50 million senior unsecured notes have a term of 10 years, a fixed rate of interest at 5.6% and are not subject to interest rate risk.

Liberty Utilities (West)'s U.S. $70 million senior unsecured private debt placement at the California Utility is split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes. As such these notes are not subject to interest rate risk.

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of $0.28 per share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensure APUC's long-term success. Based on the level of dividends paid during the year ended December 31, 2011, cash provided by operating activities exceeded dividends declared by 2.1 times.

As at December 31, 2011, APUC had cash on hand of $72.9 million and $80.4 million available to be drawn on the Facility. APUC reduced its level of short-term borrowings through the renewal of the Facility on February 14, 2011 for a three year term and through a U.S. $50 million private placement debt financing at Liberty Utility (South) on December 22, 2010. On July 25, 2011, APCo completed a private placement offering of the Senior Unsecured Debentures with a principal amount of $135 million. Net proceeds from the debentures were used to repay the project debt on APCo's AirSource senior debt financing which would have matured on October 2011, and to reduce amounts outstanding under APCo's senior credit facility. See the *Liquidity and Capital Reserves* section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facility.

The long term portion of Facility and project specific debt total approximately $331.1 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million on an annual basis.

- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $1.4 million on an annual basis.

- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million.

- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 130,000 MW-hrs in fiscal 2012. While the Tinker facility is expected to provide the majority of the energy required to service these customers, AES anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that AES was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $1.3 million on an annualized basis.

  This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 70,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. $50 per MW-hr. The mark-to-market value of these forward energy purchase contracts at December 31, 2011 was a net liability of U.S. $1.2 million.

Liberty Utilities is exposed to energy price risk in its Liberty Utilities (West) region which is mitigated through certain regulatory constructs. Liberty Utilities (West) provides electric service to the Lake Tahoe basin and surrounding areas at rates approved by the CPUC. The utility purchases the energy requirements for its customers from NV Energy at rates reflecting NV Energy's system average costs. In the event that these rates change, each $10.00 change per MWhr would result in a change in expense of approximately U.S. $6.5 million on an annualized basis.

The rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance, including carrying charges, does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to the California Utility's approved rates (including carrying charges associated therewith), substantially eliminating the commodity risk associated with the purchase of power.

OPERATIONAL RISK MANAGEMENT

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter. A more detailed assessment of APUC's business risks is also set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property. The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Utilities) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

Regulatory Risk

Profitability of APUC businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Utilities' facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Utilities regularly works with its governing authorities to manage the affairs of the business.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

Liberty Utilities' facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its consolidated financial statements as at December 31, 2011.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

Liberty Utilities faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2011.

Cycles and Seasonality

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

At Liberty Utilities (South), demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

For Liberty Utilities (West), demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Liberty Utilities (West) provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

APCo owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. For additional comments on this matter, see *"Business Associations with APMI and Senior Executives - Trafalgar"*.

On December 19, 1996, the Attorney General of Québec ("Québec AG") filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management. The water lease contains a "hold harmless" clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the "Federal Authorities") into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $4.8 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, APCo accrued $1.0 million of water lease owed to Québec AG for 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $0.3 million were also recorded in 2011.

Obligations to serve

Liberty Utilities may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Utilities may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Disclosure Controls

At the end of the fiscal year ended December 31, 2011, APUC carried out an evaluation, under the supervision of and with the participation of the APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2011, APUC's disclosure controls and procedures are effective.

Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the

risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2011 based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2011.

During the year ended December 31, 2011, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. There was no significant impact of the transition to U.S. GAAP on APUC's internal controls, information technology systems and financial reporting expertise requirements. No financial covenants were impacted by APUC's conversion to U.S. GAAP.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2011.

Millions of dollars (except per share amounts)	**1st Quarter 2011**	**2nd Quarter 2011**	**3rd Quarter 2011**	**4th Quarter 2011**
Revenue	$71.7	$66.8	$66.0	$72.1
Net earnings /(loss)	5.0	7.3	19.6	(8.5)
Net earnings / (loss) per share	0.05	0.07	0.16	(0.07)
Total Assets	1,175.8	1,177.7	1,263.1	1,282.6
Long term debt*	461.0	530.0	558.9	463.8
Dividend declared per share	0.065	0.065	0.07	0.07
	1st Quarter 2010*	**2nd Quarter 2010***	**3rd Quarter 2010***	**4th Quarter 2010**
Revenue	$ 45.9	$ 42.7	$ 45.4	$48.4
Net earnings / (loss)	3.5	(2.2)	1.5	15.6
Net earnings / (loss) per share	0.04	(0.02)	0.02	0.17
Total Assets	966.2	983.2	969.4	1,016.9
Long term debt*	434.0	446.7	452.8	450.8
Dividend declared per share	0.06	0.06	0.06	0.06

* Long term debt includes long term liabilities, the Facility, convertible debentures and other long term obligations

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $42.7 million and $72.1 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of $19.6 million and a net loss of $8.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Critical Accounting Estimates and Polices

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue and fair value of derivatives. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated useful lives and recoverability of Long-Lived Assets and Intangibles

The provisions for depreciation of utility property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets (3 to 75 years). Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives (3 to 60 years) of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of APUC's assets and result in an impairment charge.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to Liberty Utilities' operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or write down. At December 31, 2011, APUC had recorded regulatory assets of $5.0 million and regulatory liabilities of $21.7 million.

Unbilled Energy Revenues

Revenues related to electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings. Historically, any differences between the actual and estimated amounts have been immaterial.

Derivatives

APUC uses derivative instruments to manage exposure to changes in electricity prices and interest rates. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value, with changes in the derivative's fair value recognized currently in earnings. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations.

Additional disclosure of APUC's critical accounting estimates is also available SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Changes in Accounting Policies

Accounting Framework

The Consolidated Financial Statements and accompanying notes have been prepared in accordance with U.S generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required per Regulation S-X provided by the Securities and Exchange Commission ("SEC") Guidance. These are APUC's first U.S. GAAP annual consolidated financial statements.

APUC's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the annual consolidated financial statements for the year ended December 31, 2010. Descriptions of the effect of the transition from Canadian GAAP to U.S. GAAP on APUC's financial position, financial performance and cash flows as at and for the two years ended December 31, 2010 are provided in note 24 of the consolidated financial statements for the year ended December 31, 2010. The accounting policies set out in the annual Consolidated Financial Statements for the year ended December 31, 2011 have been consistently applied to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

APUC has retrospectively adopted U.S. GAAP as its financial reporting accounting framework starting in 2011. U.S. GAAP reporting is permitted by Canadian securities laws and for companies listed on the TSX which are subject to reporting obligations under U.S. securities laws as an alternative to adoption of International Financial Reporting Standards ("IFRS"). APUC has concluded that U.S. GAAP is the accounting framework that provides its shareholders and other readers of its financial statements the most useful and relevant basis for financial reporting given the significance of its rate regulated businesses. U.S. GAAP includes accounting standards for rate-regulated activities within the financial statements. Except where otherwise indicated, comparative amounts in this MD&A have been restated from the amounts previously reported under Canadian GAAP.

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2011.

March 21, 2012

Ian Robertson	David Bronicheski
Chief Executive Officer	Chief Financial Officer

KPMG LLP
Chartered Accountants
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, Ontario M5H 2S5
Canada

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheet as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with US generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2011 and December 31, 2010, and its consolidated results of operations and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

Algonquin Power & Utilities Corp.

Consolidated Balance Sheets

(thousands of Canadian dollars)

		December 31, 2011		December 31, 2010
ASSETS				
Current assets:				
Cash and cash equivalents	$	72,887	$	4,749
Short term investments (note 1(e))		833		3,674
Accounts receivable net of allowance for doubtful accounts of $255 and $380 (note 22)		44,394		25,875
Due from related parties (note 15)		2,275		718
Prepaid expenses		5,620		3,546
Supplies and consumables inventory		2,714		-
Current portion of notes receivable		482		1,172
Current portion of deferred tax asset (note 14)		13,022		14,015
Current portion of tax receivable (note 14)		133		-
Current regulatory assets (note 8)		2,458		-
		144,818		53,749
Long-term investments and notes receivable (note 5)		39,820		37,179
Deferred non-current income tax asset (note 14)		67,671		74,006
Property, plant and equipment (note 6)		945,956		761,740
Intangible assets (note 7)		55,269		73,886
Goodwill		9,710		995
Restricted cash (note 1(f))		4,693		3,564
Deferred financing costs		8,503		5,991
Non-current regulatory assets (note 8)		2,571		2,484
Other assets		3,577		3,355
	$	1,282,588	$	1,016,949
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$	8,382	$	2,182
Accrued liabilities		47,102		29,534
Current regulatory liabilities		2,469		-
Due to related parties (note 15)		1,795		1,534
Dividends payable		9,566		5,719
Current portion of long-term liabilities (note 9)		1,624		70,490
Current portion of other long-term liabilities (note 11)		1,037		420
Current portion of advances in aid of construction (note 1(o))		604		591
Current portion of derivative instruments (note 22)		2,935		2,338
Current income tax liability (note 14)		407		200
Current portion of deferred credit		6,314		11,020
Deferred income tax liability (note 14)		723		514
		82,958		124,542
Long-term liabilities (note 9)		331,092		189,468
Convertible debentures (note 10)		122,297		181,760
Other long-term liabilities (note 11)		11,027		11,405
Advances in aid of construction (note 1(o))		74,547		54,524
Non-current regulatory liabilities (note 8)		19,184		-
Deferred non-current income tax liability (note 14)		53,231		79,442
Derivative instruments (note 22)		5,209		3,525
Deferred credits (note 14)		30,348		32,222
Equity (note 12):				
Shareholders' capital		975,263		795,329
Additional paid-in capital		1,525		1,612
Deficit		(366,080)		(357,035)
Accumulated other comprehensive loss		(96,510)		(99,845)
Total Equity attributable to shareholders of Algonquin Power and Utilities Corp.		514,198		340,061
Non-controlling interest (note 3(a))		38,497		-
Total Equity		552,695		340,061
Commitments and contingencies (note 18)				
Subsequent events (notes 3, 6, 7, 8, 9, 10 and 12)				
	$	1,282,588	$	1,016,949

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

	2011	2010
Revenue:		
Non-regulated energy sales	$ 134,232	$ 129,977
Regulated energy sales and distribution	77,368	-
Waste disposal fees	16,406	9,039
Regulated water reclamation and distribution	44,989	38,011
Other revenue (note 17)	3,643	3,331
	276,638	180,358
Expenses		
Operating	88,420	69,568
Regulated commodities purchased	46,508	-
Non-regulated fuel for generation	24,628	25,929
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Administrative expenses	17,534	14,886
Write down of long-lived assets (notes 6 and 7)	16,520	2,492
Gain on foreign exchange	(652)	(528)
	238,784	158,962
Operating income	37,854	21,396
Interest expense	30,441	24,839
Interest, dividend income and other income (notes 16)	(5,659)	(5,164)
Acquisition related costs	2,965	3,015
Loss on derivative financial instruments (note 22 (c))	5,844	1,103
	33,591	23,793
Earnings (loss) from operations before income taxes	4,263	(2,397)
Income tax expense (recovery) (note 14)		
Current	300	(69)
Deferred	(23,339)	(20,722)
	(23,039)	(20,791)
Net earnings	27,302	18,394
Net earnings attributable to non-controlling interests	3,921	444
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 23,381	$ 17,950
Basic net earnings per share (note 19)	$ 0.20	$ 0.19
Diluted net earnings per share (note 19)	$ 0.20	$ 0.19

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)

	2011	2010
Net Earnings	$ 27,302	$ 18,394
Other comprehensive income (loss), before tax:		
Foreign currency translation adjustment due to accounting change (note 1(t))	-	(37,605)
Increase in unfunded pension obligation (note 1(q))	(48)	-
Foreign currency translation adjustment	4,272	(13,528)
Other comprehensive income, before tax:	4,224	(51,133)
Income tax expense related to items of other comprehensive income	-	-
Other comprehensive income (loss), net of tax:	4,224	(51,133)
Comprehensive income (Loss)	31,526	(32,739)
Less: comprehensive income attributable to the non-controlling interest	4,810	(444)
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp	$ 26,716	$ (33,183)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

	2011	2010
Cash provided by (used in):		
Operating Activities:		
Net earnings	$ 27,302	$ 18,394
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Other amortization	2,192	2,148
Gain on sale of assets	(357)	-
Deferred taxes	(23,339)	(20,722)
Unrealized loss (gain) on derivative financial instruments	2,324	(7,142)
Share-based compensation	769	108
Write down of long-lived assets	16,520	2,492
Unrealized foreign exchange gain	-	(414)
Changes in non-cash operating items (note 20)	(1,542)	(85)
	69,695	41,394
Financing Activities:		
Cash dividends (note 13)	(28,582)	(18,901)
Cash distributions to non-controlling interest	(523)	(444)
Issuance of common shares	118,846	-
Deferred financing costs	(3,642)	(1,194)
Increase in long-term liabilities	204,759	98,787
Decrease in long-term liabilities	(134,932)	(80,078)
Increase in advances in aid of construction	6,288	4,857
Decrease in other long-term liabilities	(297)	(342)
	161,917	2,685
Investing Activities:		
Decrease / (increase) in restricted cash	(1,036)	575
Decrease / (increase) in short-term investments	(833)	36,212
Increase in other assets	(2,438)	(90)
Distributions received in excess of equity income	3,839	882
Receipt of principal on notes receivable	1,172	410
Increase in non-controlling interest	1,351	-
Proceeds from liquidation of Highground assets	1,073	170
Increase in long-term investments and notes receivable	(6,900)	(14,759)
Proceeds from sale of property, plant and equipment	1,583	-
Additions to property, plant and equipment	(60,745)	(20,789)
Acquisitions of operating entities (note 3(a))	(100,058)	(44,397)
	(162,992)	(41,786)
Effect of exchange rate differences on cash	(482)	(126)
Increase in cash and cash equivalents	68,138	2,167
Cash and cash equivalents, beginning of the period	4,749	2,582
Cash and cash equivalents, end of the period	$ 72,887	$ 4,749
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 28,143	$ 21,562
Cash paid during the period for income taxes	$ 195	$ (285)
Non-cash transactions		
Property, plant and equipment acquisitions in accruals	$ 8,556	$ -

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statement of Equity

(thousands of Canadian dollars)

For the year ended December 31, 2011:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2010	$ 795,329	$ 1,612	$ (357,035)	$ (99,845)	$ -	$ 340,061
Dividends declared and distributions to non-controlling interests	-	-	(32,426)	-	(523)	(32,949)
Conversion and redemption of convertible debentures	59,973	(815)	-	-	-	59,158
Issuance of common shares	118,888	-	-	-	-	118,888
Stock compensation expense	-	728	-	-	-	728
Acquisition of Liberty Energy (California)	-	-	-	-	34,210	34,210
Amounts received in connection with Highground transaction (note 3 (h))	1,073	-	-	-	-	1,073
Net earnings			23,381		3,921	27,302
Other comprehensive income	-	-	-	3,335	889	4,224
Balance, December 31, 2011	$ 975,263	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$ 552,695

For the year ended December 31, 2010:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI (CTA)	Non-controlling interests	Total
Balance, December 31, 2009	$ 785,828	$ 1,487	$ (352,220)	$ (48,712)	$ -	$ 386,383
Dividends declared and distributions to non-controlling interests	-	-	(22,765)	-	(444)	(23,209)
Conversion and redemption of convertible debentures	4,568	17	-	-	-	4,585
Stock compensation expense	-	108	-	-	-	108
Amounts received in connection with Highground transaction (note 3 (h))	170	-	-	-	-	170
Issuance pursuant to management internalization	4,763	-	-	-	-	4,763
Net earnings			17,950		444	18,394
Other comprehensive loss	-	-		(51,133)	-	(51,133)
Balance, December 31, 2010	$ 795,329	$ 1,612	$ (357,035)	$ (99,845)	$ -	$ 340,061

Notes to the Consolidated Financial Statements

December 31, 2011 and 2010
(in thousands of Canadian dollars except as noted and amounts per share)

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water, gas and energy utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements.

APUC's power generation business unit conducts business under the name Algonquin Power Co. ("APCo"). APCo owns or has interests in renewable energy facilities and thermal energy facilities representing more than 450 MW of installed electrical generation capacity. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co. ("Liberty Utilities"). Liberty Utilities businesses operate under two separately managed regions – Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco). Liberty Utilities (South) currently owns a portfolio of utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois. Liberty Utilities (West) currently owns a 50.001% interest in an electric distribution utility serving the Lake Tahoe region of California (the "California Utility"). APUC has announced an agreement to acquire, subject to regulatory approval, the remaining 49.999% interest in the California Utility (see note 3 (a)). Liberty Utilities has also announced an agreement to acquire, subject to regulatory approval, Granite State Electric Company, a New Hampshire electric distribution company, and EnergyNorth Natural Gas Inc., a regulated natural gas distribution utility (see note 3 (b)).

The regulated utility operating companies owned by Liberty Utilities are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (see note 8).

1. Significant accounting policies

(a) Basis of preparation:

The accompanying consolidated financial statements and accompanying notes have been prepared in accordance with U.S. generally accepted accounting principles in the United States (“U.S. GAAP”) and follow disclosures required under Regulation S-X provided by the Securities and Exchange Commission (“SEC”). These are the Company’s first U.S. GAAP annual consolidated financial statements.

The Company's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the audited annual financial statements for the year ended December 31, 2010. The accounting policies set out below have been consistently applied under U.S. GAAP to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

(b) Basis of consolidation:

The accompanying consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities (“VIEs”) where the Company is the primary beneficiary. Intercompany transactions and balances have been eliminated.

(c) Accounting for rate regulated operations:

APUC’s regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations (“ASC 980”). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Management believes the regulatory assets recorded in these financial statements are probable of recovery either because the Utilities received prior Regulator approval or due to regulatory precedent set for similar circumstances. Included in Note 8, Regulatory Assets & Liabilities are details of regulatory assets and liabilities, and their current regulatory treatment.

Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation to the extent permitted by the regulator. It represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction).

The electric utilities’ and the water utilities’ accounts are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and NARUC, respectively.

(d) Cash and cash equivalents:

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

(e) Short term investments:

Short term investments, consist of money market instruments with maturities commencing from January 2012 and are recorded at current market value. Included in short term investments is an investment of $nil (U.S. $nil) which is denominated in U.S. dollars (December 31, 2010 - $3,674 (U.S. $3,694)).

1. Significant accounting policies (continued)

(f) Restricted cash:

Restricted cash represent reserves and amounts set aside pursuant to requirements of various debt agreements. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the current receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(h) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant, and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and replacement cost.

(i) Property, plant and equipment:

Property, plant and equipment, consisting of renewable and thermal generation assets, electrical, water and wastewater distribution assets, equipment and land, are recorded at cost. The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for equity funds used during construction ("AFUDC") for regulated property. Plant and equipment under capital leases are stated at the present value of minimum lease payments.

AFUDC reflects the cost of debt or equity funds used to finance construction and only is capitalized as part of the cost of regulated utility plant where such treatment is permitted by the regulator. AFUDC amounts capitalized are included in rate base for establishing utility rates. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835. The interest capitalized that relates to debt reduces interest expense on the income statement. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the Statement of Operations.

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued):

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method. The range of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2011	2010	2011	2010
Generation				
Renewable	3 – 60	3 – 60	31	31
Thermal	3 – 40	3 – 40	22	22
Distribution				
Electrical	15 - 75	N/A	52	N/A
Water & wastewater	5 – 50	5 – 50	25	25
Equipment	5 – 50	5 – 50	24	24

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(j) Intangibles:

The fair value of power sales contracts and energy sales contracts acquired in business combinations are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition for power sales contracts and 12 months for energy sales contracts.

Customer relationships acquired in business combinations are amortized on a straight-line basis over their estimated life of 40 years.

1. Significant accounting policies (continued)

(k) Goodwill:

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in rate-base and is not amortized.

In accordance with ASC Update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment" issued by the FASB in September 2011, the Company annually assesses qualitative factors to determine whether it is more likely than not that the fair value of goodwill is less than its carrying amount. If it is more likely than not that its fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(l) Impairment of long-lived assets:

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Assets Held and Used: Recoverability of assets held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

Assets Held for Sale: Recoverability of assets held for sale is measured by comparing the carrying amount of an asset to its fair value less the cost to sell. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value less estimated costs to sell.

(m) Variable interest entities:

The Company performs analysis to assess whether its operations and investments represent variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE, since the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company. Total generating assets and long-term debt of Long Sault amount to $46,160 (2010 -$47,757) and to $38,136 (2010 -$39,033), respectively. The financial performance of Long Sault reflected on the statement of operations includes non-regulated energy sales of $9,804 (2010 -$7,037), operating expenses and amortization of $3,001 (2010 -$2,572) and interest expense of $3,984 (2010 - $4,126).

1. Significant accounting policies (continued)

(n) Long-term investments and notes receivable:

Investments in which APUC has significant influence but not control or joint control are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the Consolidated Statement of Operations. All other equity investments where APUC does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and the carrying amounts are adjusted only for other-than-temporary declines in value and additional investments. Income is recorded when dividends are received.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are initially recorded at cost, which is generally face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity.

An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate. The Company does not accrue interest when a note is considered impaired. When ultimate collectability of the principal balance of the impaired note is in doubt, all cash receipts on impaired notes are applied to reduce the principal amount of such notes until the principal has been recovered and are recognized as interest income thereafter. Impairment losses are charged against the allowance and increases in the allowance are charged to bad debt expense. Notes are written off against the allowance when all possible means of collection have been exhausted and the potential for recovery is considered remote.

(o) Advances in aid of construction:

The Company has various agreements with real estate development companies conducting business within the Company's service territories (the "developers"), whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development. These amounts are recorded as Advances in Aid of Construction in other long-term liabilities. In many instances, developer advances are subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods ranging from 10 to 20 years. Generally, advances not refunded within the prescribed period are not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to cost of property, plant and equipment. In 2011, $1,107 (2010 - $nil) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Other long-term liabilities:

Other long-term liabilities include deferred water rights. Deferred water rights are related to a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment, which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

1. Significant accounting policies (continued)

(p) Other long-term liabilities (continued):

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Utilities' obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be credit worthy.

(q) Pension plan:

Liberty Utilities (West) has a defined benefit cash balance pension plan covering substantially all its employees, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The plan interest credit rate varies from year-to-year based on the five-year U.S. Treasury bonds yield plus 0.25%. Employees' benefits under the plan are fully vested upon completion of three years of service. The Company's policy is to make contributions within the range determined by generally accepted actuarial principles. The costs of the Company's pension for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit plan on the consolidated balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in Accumulated other comprehensive income ("AOCI"). The projected benefit obligation of $230 exceeds the fair value of the plan assets of $200 as at December 31, 2011. Benefit cost of $182 and actuarial loss of $48 are reflected in earnings and other comprehensive income, respectively. The assumptions used in calculating the pension obligation include a discount rate of 4%, expected return on plan assets of 6% and rate of compensation increase of 4%. As at December 31, 2011, plan assets are invested in fixed income securities.

(r) Asset retirement obligations:

The Company completes periodic reviews of potential asset retirement obligations that may require recognition. The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations. Actual expenditures incurred are charged against the accumulated obligation. Based on APUC's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations have been recorded.

(s) Recognition of revenue:

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and waste water collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled revenues are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

1. Significant accounting policies (continued)

(s) Recognition of revenue (continued):

Revenues related to utility energy sales and distribution are recorded based on metered energy consumptions by customers, which occurs on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns, line loss and current tariffs.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts is recognized based on actual tonnage at the expected price for the contract year.

Interest from long-term investments is recorded as earned.

(t) Foreign currency translation:

The Company's reporting currency is the Canadian dollar.

The Company's US operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income ("OCI") and are accumulated in a component of equity on the consolidated balance sheet and are not recorded in income unless there is a complete sale or substantially complete liquidation of the investment.

As a result of the change relating to conversion of the Company from an income trust to a corporate structure at the end of 2009, the Company re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the US divisions operate. The Company concluded that the functional currency of the US operations of the Renewable Energy and Thermal Energy divisions has become the U.S. dollar. Consequently, these divisions have been prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37,605 resulting from the current rate translation of non-monetary items, principally property, plant and equipment and intangible assets, as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

(u) Stock Based Compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value using the Black-Scholes option pricing model. Liability classified awards are measured at fair value based on the average common share price over the five days immediately preceding the date of issue and at the end of the reporting period using the average over the days ending on the financial statement date.

1. Significant accounting policies (continued)

(v) Income taxes:

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment. Income tax credits are treated as a reduction to current income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company follows FASB ASC 740-10 and recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(w) Financial instruments and derivatives:

APUC has classified its cash and cash equivalents, short term investments, and restricted cash as held-for-trading, which are measured at fair value. Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the respective asset`s carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company`s credit facility and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. Deferred financing costs, premiums and discounts on long- term debt are amortized using the effective interest method while deferred financing costs relating to revolving credit facilities are amortized on a straight-line basis over the term of the facility.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values and the change in fair value is included in the Consolidated Statements of Operations. None of the derivatives were designated in hedging relationships for accounting purposes. The Company's derivative program is not designed or operated for trading or speculative purposes.

Liberty Utilities (West) enters into Power Purchase Agreements ("PPA") for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be marked-to-market and are accounted for on an accrual basis. We evaluate our counterparties on an on-going basis for non-performance risk to ensure it does not impact our conclusion with respect to this exemption.

1. Significant accounting policies (continued)

(x) Fair Value Measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principle or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(y) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(z) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of deferred tax assets, assessments of asset retirement obligations, and the fair value of financial instruments, derivatives, share-based compensation and contingent consideration. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently Adopted Accounting Pronouncements

In December 2010, the FASB issued ASC update No. 2010-28, "Intangibles-Goodwill and Other (Topic 350), When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts, a consensus of the FASB Emerging Issues Task Force." This amendment modifies guidance for Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. The adoption of this update did not have a material impact on the Company's financial statements.

2. Recently issued accounting pronouncements (continued)

(a) Recently Adopted Accounting Pronouncements (continued)

In December 2010, the FASB issued ASC update No. 2010-29, "Business Combinations (Topic 805), Disclosure of Supplementary Pro Forma Information for Business Combinations, a consensus of the FASB Emerging Issues Task Force." This amendment clarifies the periods for which pro forma financial information is presented. The acquisition of the California Utility occurred on January 1, 2011 and therefore the Statement of Operations for the year ended December 31, 2011 contains a full year of operating results from this acquisition. Accordingly pro forma financial statements would not provide any additional information. As the business combination was an acquisition of a division of the vendor for which comparable results from operations for the previous year are not available, pro forma financial statements for the comparative period are not provided as they cannot be practicably obtained. The adoption of this update did not have a material impact on the Company`s financial statements.

In September 2011, the FASB issued ASC update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment". This Update revises how an entity tests goodwill for impairment. The new guidance allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity is no longer required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. As permitted by the Update, the Company has early adopted this standard in these annual financial statements for the year ended December 31, 2011. The adoption of this update did not have a material impact on the Company`s financial statements.

In June 2011, the FASB issued ASC update No. 2011-05 "Presentation of Comprehensive income (Topic 220)". This Update provides accounting guidance on presentation of comprehensive income. The new guidance eliminates the current option to report Other comprehensive income ("OCI") and its components in the statement of changes in stockholders' equity. The new guidance requires the changes in OCI be presented either in a single continuous statement of net income and OCI or in two separate but consecutive statements. As permitted by the Update, the Company has early adopted the presentation guidance in these annual financial statements for the year ended December 31, 2011. The amendments resulted in presentation changes only in the consolidated financial statements.

Subsequently in December 2011, the FASB issued ASC update No. 2011-12, "Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05". The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCI.

(b) Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This newly issued accounting standard requires an entity to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this accounting standard only requires enhanced disclosure, the adoption of this standard is not expected to have an impact our financial position or results of operations.

2. Recently issued accounting pronouncements (continued)

(b) Recent Accounting Guidance Not Yet Adopted (continued)

In May 2011, the FASB issued ASC update No. 2011-04 “Fair Value Measurement (Topic 820)”. This Update amends the accounting and disclosure requirements for fair value measurements. The new guidance expands the disclosures about fair value measurements categorized within Level 3 of the fair value hierarchy and requires categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The new guidance will be effective for the Company’s quarter ending March 31, 2012, and will be applied prospectively. Other than requiring additional disclosures, the adoption of this guidance is not expected to have a material impact on the Company’s consolidated financial statements.

3. Acquisitions

(a) Acquisition of California electrical generation and regulated distribution utility

On January 1, 2011, APUC and Emera Inc. (“Emera”) closed the acquisition of the “California Utility” for a purchase price of approximately $135,343 (U.S. $136,077). Through its wholly owned subsidiary Liberty Energy (California), APUC owns 50.001% of the shares of California Pacific Utility Ventures LLC, which acquired the California Utility and has concluded it controls the acquired entity. Liberty Energy (California) provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The other 49.999% of the shares were acquired by Emera in the same transaction. The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition.

On April 29, 2011, Emera agreed to sell its 49.999% interest in Liberty Energy (California) to APUC in exchange for 8,211,000 shares of APUC. The transaction is subject to regulatory approval and is expected to close in 2012.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date, as well as the fair value at the acquisition date of the non-controlling interest in Liberty Energy (California):

Working capital	$ 8,964
Property, plant and equipment	146,064
Deferred income tax asset	2,056
Goodwill	8,268
Current portion of other long-term liabilities	(671)
Advances in aid of construction	(10,434)
Other long-term liabilities	(1,988)
Regulatory liabilities	(16,916)
Total net assets acquired	$ 135,343

The acquisition was funded as follows:

Contribution of equity by APUC in 2011	$ 29,074
Contribution of equity by APUC in 2010	3,787
Non-controlling interest portion of purchase price paid by Emera	32,860
Debt financing	69,622
Total acquisition consideration	$ 135,343

3. Acquisitions (continued)

(a) Acquisition of California electrical generation and regulated distribution utility (continued):

In connection with the acquisition, the Company issued 8,523,000 shares at a price of $3.25 per share to Emera pursuant to a subscription receipt agreement. The $27,700 cash proceeds of the subscription receipts were used to fund a portion of the cost of acquisition of the California Utility.

The determination of the fair value of assets and liabilities acquired has been based upon fair value measurements.

Goodwill is calculated as the excess of the purchase price over the fair value of net assets acquired and the contributing factors to the amount recorded include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. All of the goodwill was allocated to the Liberty Utilities (West) segment.

Property, plant & equipment of Liberty Energy (California) are amortized on a straight line basis, ranging from 15 to 75 years in accordance with regulatory requirements.

The Company incurred $2,572 in total acquisition-related costs (2010 - $2,210); of which $362 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

As the acquisition closed on January 1, 2011, the financial statements for the year ended December 31, 2011 contain a full year of operating results for the utility. Liberty Energy (California) contributed revenue of $77,367 and earnings of $2,987 to the Company's results for the year ended December 31, 2011. The disclosure of pro forma revenue and earnings related to 2010 is impracticable since the assets acquired were part of a small division of a much larger utility; separate financial statements were not maintained by the vendor of the assets, the regulated tariff driving revenue formulae has changed, the rate-base used in determining rates was not identical to the assets acquired and the operating costs were subject to extensive allocation.

(b) Acquisition of Regulated Water Utilities

On September 20, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of Noel Water Co., Inc. ("Noel"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $903 was paid in cash. The following assets were acquired at fair values: working capital of $28 and property, plant and equipment of $729. Goodwill amounting to $146 was recognized.

On November 9, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of KMB Utility Corporation ("KMB"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $350 was paid in cash. The following assets were acquired at fair values: working capital of $43 and property, plant and equipment of $265. Goodwill amounting to $42 was recognized.

Both utilities are located in the state of Missouri.

(c) Agreement to Acquire New Hampshire Electric and Gas Utilities

On December 9, 2010, Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company, a regulated electric utility, and EnergyNorth Natural Gas Inc. a regulated natural gas utility from National Grid USA ("National Grid") for total cash consideration of U.S. $285,000 plus working capital and subject to a final closing adjustment.

3. Acquisitions (continued)

(c) Agreement to Acquire New Hampshire Electric and Gas Utilities (continued)

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12,000,000 APUC common shares upon closing of the transactions at a purchase price of $5.00 per share. The receipt of cash from Emera and issuance of the shares is contingent on closing of these acquisitions and consequently the subscription receipts have not been recorded in the financial statements.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

The Company incurred $3,271 in total acquisition-related costs (2010 - $1,889); of which $1,382 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

(d) Agreement to Acquire Mid-West Gas Utilities

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos Energy Corporation ("Atmos Energy") to acquire certain regulated natural gas distribution utility assets (the "Mid-West Utilities") located in Missouri, Iowa, and Illinois. Total purchase price for the Mid-West Utilities is approximately U.S. $124,000, subject to certain working capital and other closing adjustments.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

The Company incurred $398 in total acquisition-related costs during 2011 (2010 - $nil). All such costs have been expensed in the consolidated Statement of Operations.

(e) Agreement to Acquire Solar Energy Project

On November 27, 2011, APCo entered into agreements to acquire rights, subject to Ontario Power Authority approval, to develop a 10 MW-AC solar project located near Cornwall, Ontario which has been granted an Ontario Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the power sale contract is $4,500 plus additional contingent consideration of $3,500 that is based on achieving certain construction milestones.

On December 30, 2011 Ontario Power Authority Approval was received and the transaction closed on January 4, 2012. Following the completion of all regulatory submissions and approvals, construction of the solar facility is expected to begin in the second half of 2012, with a commercial operation date estimated in early 2013.

(f) Power Purchase agreement for Chaplin Wind Project

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement with SaskPower for development of a 177 –MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan. The project has a targeted commercial operation date of December, 2016. The 25 year power purchase agreement features a rate escalation provision of 0.6% throughout the term of the agreement.

3. Acquisitions (continued)

(g) Highground Capital Corporation

In 2008, the Company entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and the Company issued equity in the form trust units to the Highground shareholders and CJIG, in exchange for $26.2 million of cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

(h) Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind projects in the United States from Gamesa Corporación Tecnológica, S.A. ("Gamesa") for total consideration of approximately U.S. $269 million. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissionings near the end of 2012.

4. Accounts receivable

Accounts receivable as of December 31, 2011, include unbilled receivables of $11,304 (December 31, 2010 - $1,552) in the regulated utilities. The unbilled revenue is an estimate of the amount of utility revenue since the date the meters were last read.

5. Long-term investments and notes receivable

Long-term investments and notes receivable consist of the following:

	2011	2010
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 4,926	$ 8,197
25% of Class B non-voting shares of Cochrane Power Corporation	5,382	5,775
45% interest in the Algonquin Power (Rattle Brook) Partnership	3,784	3,790
50% interest in the Valley Power Partnership	1,676	1,845
Red Lily Subordinated loan, interest at 12.5% (b)	6,565	6,565
Red Lily Senior loan, interest at 6.31% (b)	13,000	6,100
Chapais Énergie, Société en Commandite 12.1% interest in Tranche A and Tranche B term loans The loans bear interest at the rate of 10.789% and 4.91%, respectively	2,913	3,329
Silverleaf resorts loan, interest at 15.48% (c)	2,056	2,010
Note Receivable - Twin Falls. The note bears interest at the rate of 6.75%	-	740
	40,302	38,351
Less: current portion	(482)	(1,172)
Total long term investments and notes receivable	$ 39,820	$ 37,179

The above notes are secured by the underlying assets of the respective facilities. There is no allowance for doubtful account in regards to the notes receivable as at December 31, 2011 and 2010.

5. Long-term investments and notes receivable (continued)

(a) Red Lily I

The Red Lily I Partnership (‘Partnership”) is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 megawatt wind energy facility located in south-eastern Saskatchewan.

The Company’s investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility from the Partnership. APUC has advanced $13,000 (2010 - $6,100) under a senior debt facility to the Partnership. Another third party lender has also advanced $31,000 of senior debt to the Partnership. The Company’s senior loan to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership’s senior debt, including APUC’s portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as at December 31, 2011 was determined to be negligible.

During the year ended December 31, 2011, APUC advanced $6,900 of the senior debt to the Partnership. As of December 31, 2011 APUC has funded a total of $13,000 (December 31, 2010 - $6,100) of the senior debt and $6,565 (December 31, 2010 - $6,565) of the subordinated debt.

(b) Silverleaf Resorts Inc – Hill County

On July 29, 2010, Liberty Water, a wholly owned subsidiary of APUC, made an investment in its Hill Country facility, a part of Silverleaf Resorts Inc.’s (“SRI”) facilities in Comal County, Texas. The investment of $2,056 (U.S. $2,021) was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. This investment has been recorded in property, plant and equipment as additional capacity conveyed by SRI together with note receivable for funds advanced by APUC.

The note has a 10 year term and bears interest at 15.48%. The note is repayable in cash to the extent expansion does not form part of the rate base of the utility during the 10 year term. To the extent that the cost of the expansion becomes part of the rate base of the utility, the note will be assigned as payment to Silverleaf for the expansion costs with the excess received in cash.

6. Property, plant and equipment

Property, plant and equipment consist of the following:

2011

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$527,922	$132,779	$395,143
Thermal	194,080	78,776	115,304
Distribution			
Water & wastewater	239,190	48,716	190,474
Electricity	154,154	2,636	151,518
Land	12,203	-	12,203
Equipment	50,823	23,429	27,394
Construction in progress	53,920	-	53,920
	$ 1,232,292	$ 286,336	$ 945,956

2010

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$ 527,407	$ 114,780	$ 412,627
Thermal	191,138	69,816	121,322
Distribution			
Water & wastewater	219,744	41,840	177,904
Electricity	-	-	-
Land	11,976	-	11,976
Equipment	48,720	21,309	27,411
Construction in progress	10,500	-	10,500
	$ 1,009,485	$ 247,745	$ 761,740

Generation assets are those used to generate electricity. These assets include hydroelectric, wind and thermal generation stations, turbines, dams, reservoirs and other related equipment.

Electricity distribution assets are those used to distribute electricity within a specific geographic service territory to end users of electricity. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Water and waste water assets are those used to distribute water and collect wastewater. These assets include treating facilities and equipment, network of supply mains, pipes and canals, pumps and related generation equipment, meters, hydrants, collecting sewers and other related equipment.

Equipment assets include equipment, vehicles, inventory and information technology assets.

Renewable generation assets include cost of $94,606 (2010 - $94,606) and accumulated depreciation of $30,264 (2010 - $27,962) related to facilities under capital lease or owned by consolidated variable interest entities. Depreciation expense of facilities under capital lease was $2,302 (2010 - $2,536). Contributions received in aid of construction of $3,968 (2010 - $3,731) have been credited to the cost of the distribution assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

Equipment includes cost of $4,227 (2010 - $4,402) and accumulated depreciation of $2,079 (2010 - $2,149) related to equipment under capital lease. Depreciation expense of equipment under capital lease was $282 (2010 - $292).

6. Property, plant and equipment (continued)

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1,370 (2010 - $1,836) representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end the Company entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $200. As a result, the Company wrote down its investment in these hydro facilities to fair value, less costs associated with the sale, and recognized a charge on property, plant and equipment of $662 (2010 - $656).

In December 2011, Liberty Utilities (South) wrote down $1,058 from facilities assets based on regulatory decisions in 2011 that these costs are not capitalizable for rate-base purposes.

7. Intangible assets

Intangible assets consist of the following:

2011

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 60,044	$ 20,548	$ 39,496
Customer relationships	19,235	3,462	15,773
Energy sales contract	-	-	-
	$ 79,279	$ 24,010	$ 55,269

2010

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 102,980	$ 45,345	$ 57,635
Customer relationships	18,811	2,912	15,899
Energy sales contract	4,228	3,876	352
	$ 126,019	$ 52,133	$ 73,886

Subsequent to the year end, the Region of Peel elected not to extend the existing waste processing contract with the Company and will instead seek competitive proposals from several waste management companies, including the Company. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and the Company recognized a charge on intangible assets of $13,430.

Estimated amortization expense for intangibles for the next five years is $4,190 each year.

8. Regulatory assets and liabilities

The Company's regulated utility operating companies owned by Liberty Utilities are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company`s regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process.

The utilities periodically file rate cases with their regulators. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Regulated utilities use a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Liberty Utilities monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments. In the case of Liberty Utilities (West) and consistent with regulated utilities operating in California, the utility is required to make general rate case filings on a regular 3 year cycle. The utilities' most recent rate case was settled in 2009. The rate case was filed in February 2012 for the prospective years of 2012-2013. The regulator allows for the use of a prospective test year in the establishment of rates for the utility. The regulator also allows the use of annual adjuster mechanisms to account for inflation to labor and other expenses over the three year period of the rate case filing. In addition, a utility's rates include thresholds for capital expenditures, which once reached, can trigger adjustment mechanisms in between rate cases.

Energy Cost Adjustment Clause ("ECAC")

A portion of the revenue of Liberty Utilities (West) consists of ECAC which is designed to recoup or refund power supply costs that are caused by the fluctuations in the price of fuel and purchased power. The ECAC allowed in California mitigates the impact of changes in fuel prices and stabilizes earnings by allowing for the recovery of fuel and purchased power costs by updating rates charged on an annual basis. The mechanism consists of a base rate and amortization rate. The actual power supply costs incurred are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows Calpeco to request an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

The Post Test Year Adjustment Mechanism ("PTAM")

The PTAM allows Calpeco to update its rates annually by a cost inflation index. In addition, rates are allowed to be updated to recover the return on investment and associated depreciation of major capital projects.

8. Regulatory assets and liabilities (continued)

Power Purchase Agreement ("PPA")

Liberty Utilities (West) has entered into a five year all requirements PPA with NV Energy to provide its full electric needs at NV Energy's "system average cost" rates. The PPA had an effective starting date of January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply Liberty Utilities (West) with sufficient renewable power to satisfy the current 20% California Renewables Portfolio Standard requirement for the five-year term of the PPA. NV Energy's deliveries under the PPA are structured in a manner which satisfies the CPUC resource adequacy ("RA") requirements, and are designed to enable Liberty Utilities (West) to comply with the associated RA reporting requirements. Liberty Utilities (West) accounts for the PPA as an operating lease. The costs associated with the PPA are recoverable through the ECAC.

Regulatory assets and liabilities consist of the following:

	December 31, 2011	December 31, 2010
Regulatory assets:		
Rate case costs (i)	$ 2,161	$ 2,164
Alternative revenue program (ii)	2,789	320
Water testing costs (iii)	79	-
Total regulatory assets	$5,029	$ 2,484
Less current regulatory assets	2,458	-
Non-current regulatory assets	$2,571	$ 2,484
Regulatory liabilities		
Deferred energy costs (iv)	$ 6,708	$ -
Cost of removal (v)	14,945	-
Total regulatory liabilities	$ 21,653	$ -
Less current regulatory liabilities	2,469	-
Non-current regulatory liabilities	$ 19,184	$ -

(i) Rate case

The costs to file, prosecute and defend rate case applications are referred to as rate case costs and are generally recoverable, in whole or in part, as part of the rate case process over a prescribed period of time. Deferred rate case costs are those rate case costs the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

8. Regulatory assets and liabilities (continued)

(ii) Alternative revenue program

A rate decision by the regulator of one of Liberty Utilities (South)'s utilities has ordered a phase-in of the rate increases it has granted wherein the full rate increase will be phased in over a 12 month period. The phase-in also includes a surcharge mechanism that ensures the utility is not disadvantaged by the phase in of the new rates.

(iii) Water testing costs

Water testing costs consist of certain expenses associated with some water testing costs ordered by the regulator. These costs are allowed to be recovered in rates in future periods. The regulatory asset associated with these costs is amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

(iv) Deferred energy cost

Certain state statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased gas, fuel and purchased power.

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the consolidated statement of operations but rather is deferred and recorded as a regulatory asset on the balance sheet in accordance with the provisions of ASC 980. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to regulatory review. The Utilities also record and are eligible under the statute to recover a carrying charge on such deferred balances.

(v) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant.

Future implications of discontinuing application of regulatory accounting

Liberty Utilities regularly assesses whether it can continue to apply regulatory accounting to its operations. In the event that the criteria no longer applied to a deregulated portion of the operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory mechanism is provided. Additionally, these factors could results in an impairment on utility assets.

8. Regulatory assets and liabilities (continued)

Income statement impact of applying regulatory accounting

If Liberty Utilities had not applied regulatory accounting earnings would have been affected as follows:

	December 31, 2011	December 31, 2010
Liberty Utilities (South):		
As a result of not recognizing the alternative revenue program in advance of the full rate increase being phased in rates, the rate case costs would have been expensed as incurred and revenue recognized would have been limited to the current phase of the phase-in plan.	$(1,825)	$(332)
Liberty Utilities (West):		
Recognizing over-recovered purchased power costs net of capitalized rate-case that would have been expensed.	4,106	-
Total increase (decrease) in earnings	$ 2,281	$(332)

9. Long-term liabilities

Long term liabilities consist of the following:

	2011	2010
APCo		
Senior Unsecured Notes: $135,000 senior unsecured notes, interest rate of 5.5% maturing July 25, 2018. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012.	$ 134,778	$ -
Senior Secured Revolving Credit Facility: Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 2.5%.	-	64,500
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly interest and principal installments of $402 and maturing December, 2027.	39,033	39,844
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2011 is 2.05% (2010 – 1.33%).	19,526	19,096
Senior Debt Chute Ford: Interest rate of 11.6% repayable in blended monthly interest and principal installments of $64 and maturing April, 2020.	4,072	4,350
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matured on October 31, 2011. Monthly interest and quarterly principal payments totaled $72,146 (2010 - $1,741). The effective rate of interest for 2011 was 1.38% (2010 – 1.81%).	-	68,789
Bonds Payable: Obligation to the City of Sanger (2010 - U.S. $230).	-	229
Liberty Utilities		
Senior Notes – California Pacific Electric Company, LLLC: U.S. $45,000 senior unsecured notes, interest rate of 5.19%, maturing December 29, 2020 and U.S. $25,000, interest rate of 5.59%, maturing December 29, 2025. The notes are interest only, payable semi-annually.	71,190	-

9. Long term liabilities (continued)

	2011	2010
Senior Unsecured Notes – Liberty Water Co: U.S. $50,000 senior unsecured notes, interest rate of 5.6% maturing December 22, 2020. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and an annual principal repayment of U.S. $5,000 thereafter.	50,850	49,730
Litchfield Park Service Company Bonds: 1999 and 2001 IDA Bonds. Interest rates of 5.95% and 6.75% repayable in blended semi-annual installments maturing October 2023 and October 2031. Principal payments of U.S. $270 (2010 – U.S. $255). The balance of these notes at December 31, 2011 was U.S. $3,605 and U.S. $7,100, respectively (2010 – U.S. $3,810 and U.S. $7,165).	11,868	11,931
Bella Vista Water Loans: Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March, 2020 and December, 2017. The balance of these notes at December 31, 2011 was US$1,275 and US$83 respectively (2010 – US$1,384 and US$95)	1,399	1,489
	$ 332,716	$ 259,958
Less: current portion	(1,624)	(70,490)
	$ 331,092	$ 189,468

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to APUC, APCo or Liberty Utilities. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions/dividends to Liberty Utilities, APCo and APUC from the specific facilities.

APCo

On July 25, 2011 APCo completed a $135,000 private placement debt financing commitment at a price of $998.28 per $1,000 principal amount of debenture. The notes are senior unsecured with a seven year maturity date of July 25, 2018 and bear interest at 5.5%. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012. APCo incurred deferred financing costs of $1,685, which are being amortized to interest expense over the term of the loan using the effective interest rate method. The net proceeds of this financing were used to retire the project debt related to the St. Leon facility (Air Source Senior Debt Financing) and to reduce amounts outstanding on APCo's senior secured revolving credit facility. As of December 31, 2011, the Company had accrued $3,255 in interest payable.

9. Long term liabilities (continued)

In February 2011, APCo renewed its senior secured revolving credit facility in the maximum amount of $142,000 (the “Facility”) for a three year term with its Canadian bank syndicate. The Facility now has a maturity date of February 14, 2014. Refinancing costs and fees related to the renewal of $1,446 have been recorded as deferred financing costs in the period. On July 25, 2011, in conjunction with the APCo debenture offering discussed above, the maximum availability on the senior revolving facility was reduced to $120,000. At December 31, 2011, $0 (2010 - $64,500) has been drawn on the Facility. In addition, the availability of the revolving credit facility has been reduced for certain outstanding letters of credit in amounts totaling $39,606 (2010 - $33,122).

Therefore, APCo had $80,394 of undrawn bank facilities as at December 31, 2011. The terms of the Facility contain certain financial covenants including debt service ratios and leverage ratios which can limit the amounts available for borrowing. Based on current covenants at December 31, 2011, APCo is able to access the entire undrawn amount of the Facility. The facility is secured by a fixed and floating charge over all APCo entities.

On December 22, 2010 APUC’s subsidiary, Liberty Water Co. (“Liberty Water”), issued U.S. $50,000 senior unsecured notes with a ten year maturity date of December 2020 and bearing interest at 5.6%. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and annual principal repayments of U.S. $5,000 thereafter. As of December 31, 2011, Liberty Water incurred deferred financing costs of $1,235 (2010 - $854) which are being amortized to interest expense over the term of the loan using the effective interest rate method.

APUC’s subsidiary California Pacific Electric Company, LLC has issued U.S.$70,000 senior unsecured notes consisting of U.S. $45,000 bearing an interest rate of 5.19% maturing December 29, 2020 and U.S. $25,000 bearing an interest rate of 5.59% maturing December 29, 2025. The notes are interest only, payable semi-annually. Financing costs of $ 1,048 (2010 - $1,069) incurred with respect to this placement have been recorded in deferred financing costs.

Subsequent to year-end, on January 19, 2012, Liberty Utilities Co. entered into an agreement for a U.S. $80,000 senior unsecured revolving credit facility with a three year term at an interest rate equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.75%.

Interest paid on the long-term liabilities was $18,089 (2010 - $9,064).

9. Long term liabilities (continued)

Principal payments due in the next five years and thereafter are:

	2012	2013	2014	2015	2016	Thereafter	Total
APCo							
Senior Unsecured	$ -	$ -	$ -	$ -	$ -	$134,778	$134,778
Senior Debt Long Sault Rapids	897	993	1,094	1,211	1,340	33,498	39,033
Sanger Bonds	-	-	-	-	-	19,526	19,526
Senior Debt Chuteford	309	346	389	436	489	2,103	4,072
Liberty Utilities							
Senior Unsecured	-	-	-	-	5,085	45,765	50,850
Senior Unsecured	-	-	-	-	-	71,190	71,190
Litchfield Park Service Company Bonds	290	305	326	346	366	10,235	11,868
Bella Vista Water Loans	128	136	135	144	140	716	1,399
Total	$1,624	$1,780	$1,944	$2,137	$7,420	$317,811	$332,716

10. Convertible Debentures

2011	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$4.08	$6.00	$4.20	
Carrying value at December 31, 2010	$ 59,156	$ 59,699	$ 62,905	$ 181,760
Conversion to shares (Note12), net of costs	(59,449)	(10)	(334)	(59,793)
Amortization and accretion	293	37	-	330
Carrying value at December 31, 2011	$ -	$59,726	$62,571	$122,297
Face value at December 31, 2011	$ -	$59,957	$62,571	$122,528

2010	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$4.08	$6.00	$4.20	
Carrying value at December 31, 2009	$ 62,686	$ 59,664	$ 63,250	$ 185,600
Conversion to shares (Note 12), net of costs	(4,473)	-	(345)	(4,818)
Amortization and accretion	943	35	-	978
Carrying value at December 31, 2010	$59,156	$59,699	$62,905	$181,760
Face value at December 31, 2010	$62,470	$59,967	$62,905	$185,342

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC (note 12).

10. Convertible Debentures (continued)

The Series 3 debentures are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares per $1,000 principal amount of debentures. The debentures cannot be redeemed by APUC on or before December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 debentures' maturity, APUC can redeem the Series 3 debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 debentures with additional shares.

11. Other long-term liabilities

Other long term liabilities consist of the following:

	2011	2010
Contingent consideration	$ 1,080	$ 1,198
Deferred water rights inducement	2,927	3,008
Customer deposits	2,483	1,985
Capital Leases		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	501	535
Other	5,073	5,099
	12,064	11,825
Less: current portion	(1,641)	(1,011)
	$ 10,423	$ 10,814

12. Shareholders' Capital

Number of common shares:

	2011	2010
Common shares, beginning of period	95,422,778	93,064,120
Conversion and redemption of convertible debentures	15,300,824	1,178,478
Issuance pursuant to management internalization	-	1,180,180
Issuance of shares	25,399,178	-
Common shares, end of period	136,122,780	95,422,778

12. Shareholders' Capital (continued)

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are authorized or outstanding.

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC. As at December 31, 2011, APUC does not have any issued and outstanding preferred shares.

On June 29, 2010, the Company issued 1,180,180 shares valued at $4,763 pursuant to the Management Internalization Agreement signed on December 21, 2009. The issuance of shares and final settlement was approved by the Company's shareholders at its annual general meeting held on June 23, 2010.

In 2010, $4,473 principal amount of New Series 1 Debentures were converted at the option of the holders at a price of $4.08 for each share into 1,096,336 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $4,094 has been recorded as share capital.

In 2010, $345 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 82,142 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $311 has been recorded as share capital.

On April 1, 2011, APUC called for the redemption of the Series 1A Debentures on May 16, 2011 ("Redemption Date"). Prior to the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On May 16, 2011, APUC redeemed the remaining Series 1A Debentures by issuing and delivering 430,666 APUC shares. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

During the year ended December 31, 2011, $10 principal amount of Series 2A Debentures were converted at the option of the holders at a price of $6.00 for each share into 1,666 shares of APUC.

During the year ended December 31, 2011, $334 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 79,517 shares of APUC.

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC.

Subsequent to the year end, $66 principal amount of Series 3 Debentures were converted at the option of the holders into 15,711 shares of APUC.

12. Shareholders' Capital (continued)

Shareholders' Rights Plan

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan"). The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

Dividend reinvestment plan

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional Common Shares acquired through the reinvestment of cash dividends will be purchased in the open market or will be issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time.

Employee Share Purchase Plan

In September 2011, the Company approved an employee share purchase plan ("ESPP") which commenced in October 2011. Eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match a) 20% of employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and b) 15% of employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2011, a total of 7,176 common shares were issued to employees under the ESPP plan for a total compensation expense related to the ESPP in 2011 of $9.

12. Shareholders' Capital (continued)

Stock Option Plan

During 2010, the Company's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

The following assumptions were used in determining the fair value of share options granted:

	2011	**2010**
Risk-free interest rate	3.0%	2.9%
Expected volatility	30%	29%
Expected dividend yield	5.3%	5.9%
Expected life	8 years	8 years
Weighted average grant date fair value per option	$ 0.99	$ 0.61

12. Shareholders' Capital (continued)

Stock option activity during the period is as follows:

	Number of shares		Weighted average exercise price	Weighted average remaining contractual term		Aggregate intrinsic value
Balance at January 1, 2011	1,160,204	$	4.05	7.62	$	1,056
Granted	1,326,900		5.38	8.00		22
Balance at December 31, 2011	2,487,104	$	4.76	6.96	$	4,134
Exercisable at December 31, 2010	386,735	$	4.05	6.62	$	917

On March 14, 2012, 1,194,606 stock options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $6.22.

Directors Deferred Share Units

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company expects to settle these instruments in cash, these DSUs are accounted for as liability awards and dividends accumulated are recognized as additional compensation cost. The DSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period. As at December 31, 2011, no DSUs had been issued.

12. Shareholders' Capital (continued)

Performance Share Units

The Company approved a performance share unit plan to its employees as part of the Company's long-term incentive program. Performance share units ("PSUs") are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of shares issued can range from 0% to 144% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividend's are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized ratably over the performance period based on the Company's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest

A summary of the PSUs activity follows:

	Employees PSUs Outstanding
December 31, 2010	-
Granted	21,123
December 31, 2011	21,123

A summary of the non-vested PSUs follows:

	Employees PSUs	
	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2011	-	$ -
Granted	21,123	5.62
Non-vested at December 31, 2011	21,123	$5.62

Share-based compensation

For the year ended December 31, 2011, APUC recorded $769 (2010 - $108) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1,216 and $70 respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

13. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the year ended December 31, 2011, the Company declared cash dividends to shareholders totaling $32,426 (2010 - $22,765) or $0.24 per common share (2010 - $0.24 per common share).

On November 14, 2011, the Board declared a dividend on the Company's shares of $0.07 per share payable on January 16, 2012 to the shareholders of record on December 30, 2011 for the period from October 1, 2011 to December 31, 2011.

14. Income Taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 28.25% (2010 - 31%). The differences are as follows:

	2011	2010
Expected income tax expense / (recovery) at Canadian statutory rate	$1,204	$ (45)
Increase (decrease) resulting from:		
Recognition of deferred credit	(6,581)	(6,636)
Differences in tax rates in subsidiaries and changes in tax Rates	(861)	(202)
Change in valuation allowances	(16,834)	(5,979)
Foreign exchange on intercompany items	2,250	(6,228)
Non-taxable corporate dividend	(1,418)	(1,191)
Non-controlling interests share of income	(1,317)	-
Other permanent difference	518	(510)
Income tax recovery	$ (23,039)	$(20,791)

For the years ended December 31, 2011 and 2010, income/(loss) before taxes consists of the following:

	2011	2010
Canadian operations	$ (5,242)	$ (6,405)
U.S. operations	9,505	4,007
	$ 4,263	$ (2,398)

14. Income Taxes (continued)

As a result of the business combination transaction in 2009, APUC recorded certain additional tax attributes. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration was reflected as a deferred credit of $55,647 on the transaction date. The deferred credit is being recognized in income as a deferred income tax recovery in relative proportion to the amount of the related deferred tax assets that are utilized in the period.

Income tax expense (recovery) attributable to income/(loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2011			
Canada	$ 268	$ (1,936)	$ (1,668)
United States	32	(21,403)	(21,371)
	$ 300	$ (23,339)	$ (23,039)
Year ended December 31, 2010			
Canada	200	(1,081)	(881)
United States	(269)	(19,641)	(19,910)
	$ (69)	$ (20,722)	$ (20,791)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 are presented below:

	2011	2010
Deferred income tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ 133,625	$ 120,973
Unrealized foreign exchange difference on intercompany notes	-	17,860
Customer advances in aid of construction	6,610	5,559
Regulatory liabilities	4,313	-
Foreign exchange hedges and interest rate swaps	2,233	1,459
Total deferred income tax assets	146,781	145,851
Less: Valuation allowance	(15,063)	(31,896)
Total deferred income tax assets	131,718	113,955
Deferred tax liabilities:		
Property, plant and equipment	(96,158)	(96,554)
Intangible assets	(7,812)	(7,639)
Other	(1,009)	(1,697)
Total deferred income tax liabilities	(104,979)	(105,890)
Net deferred income tax assets	$ 26,739	$ 8,065

14. Income taxes (continued)

The valuation allowance for deferred tax assets as of December 31, 2011 and 2010 was $15,062 and $31,896, respectively. The net change in the total valuation allowance was a decrease of $16,834 in 2011 and a decrease of $5,979 in 2010. The valuation allowance at December 31, 2011 was primarily related to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carry back and carry forward periods), projected deferred taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

	2011	2010
Current deferred income tax asset	$ 13,022	$ 14,015
Non-current deferred income tax asset	67,671	74,006
Current deferred income tax liability	(723)	(514)
Non-current deferred income tax liability	(53,231)	(79,442)
	$ 26,739	$ 8,065

As at December 31, 2011, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital losses carry forwards
2015	$ 28,406
2026 and onwards	239,823
	$ 268,229

15. Related party transactions

Certain executives of APUC are shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of APCo. A member of the Board of Directors of APUC is an executive at Emera.

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for year ended December 31, 2011 were $327 (2010 - $327).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year, APUC incurred costs in connection with the use of the aircraft of $453 (2010 - $430) and amortization expense related to the advance against expense reimbursements of $274 (2010 - $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

15. Related party transactions (continued)

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008, increasing by 2.5% every 5 years to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $314 for the year ended December 31, 2011 (2010 - $266). APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

APMI is one of the two original developers of Red Lily I (note 5(b)) and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") which is an entity where Senior Executives hold equity interests. APUC and APS agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.

As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.

A contract with a subsidiary of Emera to purchase energy on Independent System Operator New England ("ISO NE") and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of $0 (2010 - $1,368) which was included as an operating expense on the consolidated statement of operations.

In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During 2011 APUC paid U.S. $260 (2010 - $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). For 2011, the Energy Services Business sold electricity amounting to $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

15. Related party transactions (continued)

As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including Sanger repowering project, the acquisition of the Clean Power Income Fund and the development of the Red Lily I wind project. The Company is currently evaluating the impact the settlement will have on the consolidated financial statements.

16. Interest, dividend and other income

Interest, dividend and other income includes the following items:

	2011	2010
Interest income	$ 2,533	$ 1,138
Dividend income	2,928	2,928
Equity income	193	431
Other	5	667
	$ 5,659	$ 5,164

17. Other revenue

Other revenue consists of the following:

	2011	2010
Hydro mulch sales	$1,352	$1,318
Red Lily development fees	209	209
Red Lily royalty income and supervisory fees	947	-
Red Lily construction services fees and natural gas sales	757	1,804
Gain on sale of assets	358	-
Other	20	-
	$ 3,643	$ 3,331

18. Commitments and Contingencies

Land and Water Lease Commitments:

Certain of the Company's operating entities have entered into agreements to lease either land, water rights or both that are used in the generation of electricity or to pay, in lieu of property tax, an amount based on electricity production. The terms of these leases have varying maturity dates that continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. APUC incurred costs of $2,654 during 2011 (2010 - $2,231) in respect of these agreements for all of its operating entities.

Contingencies:

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

On December 19, 1996, the Attorney General of Québec ("Québec AG") filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation (the "Seaway Management") under its water lease with Seaway Management. The water lease contains a "hold harmless" clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the "Federal Authorities") into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $5.4 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, the Company accrued $1,000 of water lease owed to Québec AG for the years 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $300 related to these years were also recorded in 2011.

18. Commitments and Contingencies (continued)

Other Commitments:

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2011.

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated the remaining potential remedial measures involving capital expenditures to be approximately $16,900 which may be required to comply with the legislation and which would be invested over a five year period or longer.

APUC has outstanding purchase commitments for long-term service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

	2012	2013	2014	2015	2016	Thereafter	Total
Long term service agreements	$4,559	$4,072	$4,153	$4,236	$4,321	$73,008	$94,349
Purchased power	45,053	45,155	46,375	45,867	45,053	-	227,503
Capital projects	7,871	-	-	-	-	-	7,871
Operating leases	939	609	369	282	20	-	2,219
Total	**$58,422**	**$49,836**	**$50,897**	**$50,385**	**$49,394**	**$73,008**	**$331,942**

Liberty Utilities (West) has entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2011. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

19. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the Company and the weighted average number of shares outstanding during the year. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs, shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the treasury stock method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the as if converted method. The weighted average shares outstanding during the year are as follows:

	2011	2010
Weighted average shares – basic	116,712,934	94,338,193
Dilutive effect of share-based awards	249,854	-
Weighted average shares – diluted	116,962,788	94,338,193

The shares potentially issuable as a result of the convertible debentures and 1,326,900 stock options (2010 –1,160,204) are excluded from this calculation as they are anti-dilutive.

20. Non-cash operating items

The changes in non-cash operating items is comprised of the following:

	2011	2010
Accounts receivable	$ (11,674)	$ (6,817)
Related party balances	145	-
Supplies and consumable inventory	(1,087)	-
Income tax receivable	(133)	1,143
Prepaid expenses	(2,071)	1,153
Accounts payable	3,991	5,050
Accrued liabilities	9,010	-
Current income tax liability	207	195
Net regulatory assets and liabilities	70	(809)
	$ (1,542)	$ (85)

21. Segmented Information

APUC has two operating segments: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric distribution services.

Within APCo there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Effective July 2011, the Company changed its operational segments within Liberty Utilities to be aggregated and reported by geography territory. As a result Liberty Utilities reports results under Liberty Utilities (West) Region (currently consisting of Calpeco) and Liberty Utilities (South) Region (currently consisting of Liberty Water). No changes in the aggregation of segmented financial information were required as a result of this change. As additional utilities are acquired, additional reportable segments by geographic territory may be added.

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy and Liberty Utilities (South) and Liberty Utilities (West). The development activities of APCo are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the loss on financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The interest rate swaps relate to specific debt facilities and gains and losses are allocated in the same manner as interest expense. Amounts relating to the convertible debentures are reported in the corporate segment.

The results of operations and assets for these segments are as follows:

21. Segmented Information (continued)

Operational Segments (continued)

	Year ended December 31, 2011							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non-regulated energy sales	$87,566	$46,666	$134,232	$ -	$ -	$ -	$ -	$ 134,232
Regulated energy sales and distribution	-	-	-	-	77,368	77,368	-	77,368
Waste disposal fees	-	16,406	16,406	-	-	-	-	16,406
Water reclamation and distribution	-	-	-	44,989	-	44,989	-	44,989
Other revenue	2,291	1,352	3,643	-	-	-	-	3,643
Total revenue	89,857	64,424	154,281	44,989	77,368	122,357	-	276,638
Operating expenses	29,802	44,485	74,287	22,720	62,511	85,231	38	159,556
	60,055	19,939	79,994	22,269	14,857	37,126	(38)	117,082
Depreciation of property, plant and equipment	(16,903)	(10,684)	(27,587)	(7,993)	(3,813)	(11,806)	-	(39,393)
Amortization of intangible assets	(3,007)	(2,735)	(5,742)	(691)	-	(691)	-	(6,433)
Administration expenses	(10,719)	(700)	(11,419)	(342)	(798)	(1,140)	(4,975)	(17,534)
Write down of long-lived assets	(2,032)	(13,430)	(15,462)	(1,058)	-	(1,058)	-	(16,520)
Gain on foreign exchange	-	-	-	-	-	-	652	652
Interest expense	(8,128)	(1,688)	(9,816)	(5,189)	(4,526)	(9,715)	(10,910)	(30,441)
Interest, dividend and other income	2,143	(6)	2,137	488	-	488	3,034	5,659
Acquisition related costs	-	-	-	(2,301)	(466)	(2,767)	(198)	(2,965)
Loss on derivative financial instruments	(1,068)	-	(1,068)	-	-	-	(4,776)	(5,844)
Earnings / (loss) before income taxes	$ 20,341	$ (9,304)	$ 11,037	$ 5,183	$ 5,254	$ 10,437	$ (17,211)	$ 4,263
Property, plant and equipment	$ 423,884	155,507	579,391	208,073	158,492	366,565	-	945,956
Intangible assets	25,863	7,088	32,951	-	22,318	22,318	-	55,269
Total assets	482,543	176,269	658,812	252,514	188,399	440,913	182,863	1,282,588
Capital expenditures	25,610	13,601	39,211	10,906	10,261	21,167	367	60,745
Acquisition of operating entities	-	-	-	1,253	98,805	100,058	-	100,058

21. Segmented Information (continued)

Operational Segments (continued)

	Year ended December 31, 2010							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non regulated energy sales	$ 80,117	$49,860	$129,977	$ -	$ -	$ -	$ -	$129,977
Waste disposal fees	-	9,039	9,039	-	-	-	-	9,039
Water reclamation and distribution	-	-	-	38,011	-	38,011	-	38,011
Other revenue	2,122	1,209	3,331	-	-	-	-	3,331
Total revenue	82,239	60,108	142,347	38,011	-	38,011	-	180,358
Operating expenses	29,481	43,817	73,298	22,199	-	22,199	-	95,497
	52,758	16,291	69,049	15,812	-	15,812	-	84,861
Depreciation of property, plant and equipment	(17,233)	(11,243)	(28,476)	(7,820)	-	(7,820)	(175)	(36,471)
Amortization of intangible assets	(6,670)	(2,774)	(9,444)	(700)	-	(700)	-	(10,144)
Administration expenses	(4,674)	(1,825)	(6,499)	(1,890)	-	(1,890)	(6,497)	(14,886)
Write down of long-lived assets	(1,836)	(656)	(2,492)	-	-	-	-	(2,492)
Foreign exchange gain	-	-	-	-	-	-	528	528
Interest expense	(7,742)	(770)	(8,512)	(1,911)	-	(1,911)	(14,416)	(24,839)
Interest, dividend and other income	783	633	1,416	149	-	149	3,599	5,164
Acquisition related costs	-	-	-	-	-	-	(3,015)	(3,015)
Loss on derivative financial instruments	(5,486)	-	(5,486)	-	-	-	4,383	(1,103)
Earnings / (loss) before income taxes	9,900	(344)	9,556	3,640	-	3,640	(15,593)	(2,397)
Property, plant and equipment	$412,159	$149,837	$561,996	$199,251	-	$199,251	$493	$761,740
Intangible assets	28,287	23,104	51,391	22,495	-	22,495	-	73,886
Total assets	467,589	194,906	662,495	237,513	-	237,513	116,941	1,016,949
Capital expenditures	2,331	11,554	13,885	6,644	-	6,644	260	20,789
Acquisition of operating entities	40,281	-	40,281	2,120	1,996	4,116	-	44,397

21. Segmented Information (continued)

Operational Segments (continued)

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2011 or 2010: Hydro Québec 17% (2010 - 14%), Pacific Gas and Electric 11% (2010 - 10%), Manitoba Hydro 16% (2010 – 15%), and AES 15% (2010 - 18%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

APUC and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2011	2010
Revenue		
Canada	$ 88,900	$ 72,360
United States	187,738	107,998
	$ 276,638	$ 180,358
Property, plant and equipment		
Canada	$ 474,094	$ 464,783
United States	471,862	296,957
	$ 945,956	$ 761,740
Intangible assets		
Canada	$ 25,863	$ 43,305
United States	29,406	30,581
	$ 55,269	$ 73,886
Other assets		
Canada	$ 3,577	$ 1,415
United States	-	1,940
	$ 3,577	$ 3,355

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

22. Financial instruments

a) Fair Value of financial instruments

	2011 Carrying amount	2011 Fair Value	2010 Carrying amount	2010 Fair value
Cash and cash equivalents	$ 72,887	$ 72,887	$ 4,749	$ 4,749
Short-term investments	833	833	3,674	3,674
Accounts receivable and due from related parties	46,669	46,669	26,593	26,593
Restricted cash	4,693	4,693	3,564	3,564
Notes receivable	24,534	24,534	18,744	18,744
Total financial assets	$ 149,616	$ 149,616	$ 57,324	$ 57,324
Accounts payable and due to related parties	10,177	10,177	3,716	3,716
Accrued liabilities	47,102	47,102	29,534	29,534
Dividends payable	9,566	9,566	5,719	5,719
Long-term liabilities	332,716	338,264	259,958	262,117
Convertible debentures	122,297	162,195	181,760	216,769
Interest rate swaps	6,975	6,975	5,440	5,440
Energy forward purchase contracts	1,169	1,169	378	378
Foreign exchange contracts	-	-	45	45
Total financial liabilities	$ 530,002	$ 575,448	$ 486,550	$ 523,718

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value at December 31, 2011 and 2010 due to the short-term maturity of these instruments.

Long term investments and notes receivable include equity instruments and notes receivable. The equity instruments do not have a quoted market price in an active market, and fair value cannot be reliably measured. Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities and convertible debentures at fixed interest rates and variable rates. The estimated fair value is calculated using the current interest rates.

Advances in aid of construction have a carrying value of $75,151 (2010 - $55,115) at December 31, 2011. Portions of these non-interest bearing instruments are payable annually through 2026 and amounts not paid by the contract expiration dates become nonrefundable. Their relative fair values cannot be accurately estimated because future refund payments depend on several variables, including new customer connections, customer consumption levels, and future rate increases. However, the fair value of these amounts would be less than their carrying value due to the non-interest bearing feature.

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

22. Financial instruments (continued)

b) Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2011 are as follows:

	Level 1	Level 2	Level 3	Total
Derivative liabilities:				
Energy forward purchase contracts	$ -	$ (1,169)	$ -	$ (1,169)
Interest rate swap	-	(6,975)	-	(6,975)
	$ -	$ (8,144)	$ -	$ (8,144)

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2011 or 2010.

The fair value of derivative instruments is estimated using forward curves obtained from brokers and market participants, net of estimated credit risk.

The Red Lily conversion option (note 5 (a)) is measured at fair value on a recurring basis using unobservable inputs (Level 3).The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, discount rate and estimated cash flows. There was no change in fair value of $0 during the years ended December 31, 2011 or 2010.

22. Financial instruments (continued)

c) Effect of derivative instruments on the Consolidated Statement of Operations

Loss/(gain) on derivative financial instruments consist of the following:

	2011	2010
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (45)	$ (1,424)
Interest rate swaps	1,536	(2,787)
Energy forward purchase contracts	833	(2,931)
Total change in unrealized loss/(gain) on derivative financial instruments	$ 2,324	$ (7,142)
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ 691	$ (620)
Interest rate swaps	2,138	5,929
Energy forward purchase contracts	691	2,936
Total realized loss on derivative financial instruments	$ 3,520	$ 8,245
Loss on derivative financial instruments	$ 5,844	$ 1,103

(d) Risk Management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, short term investments, accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from Power Generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

22. Financial instruments (continued)

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $4,996 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2011 the Company's exposure to credit risk for these financial instruments was as follows:

	December 31, 2011	
	Canadian $	**US $**
Cash and cash equivalents and restricted cash	$ 69,108	$ 9,149
Short term investments	833	-
Accounts receivable	14,229	29,912
Allowance for Doubtful Accounts	-	(251)
Note Receivable	22,478	2,021
	$ 106,648	$ 40,831

There are no material past due amounts in accounts receivable.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2011, in addition to cash on hand of $72,887 the Company had $80,400 available to be drawn on its senior debt facility. The senior credit facility contains covenants which may limit amounts available to be drawn. The Company`s liabilities mature as follows:

	Due less than 1 year	**Due 2 to 3 years**	**Due 4 to 5 years**	**Due after 5 years**	**Total**
Long term debt obligations	$ 1,624	$ 3,725	$ 9,556	$ 317,811	$ 332,716
Convertible Debentures	59,726	-	-	62,571	122,297
Interest on long term debt	25,571	40,241	37,250	124,807	227,869
Accounts Payable and due to related parties	10,177	-	-	-	10,177
Accrued liabilities	47,102	-	-	-	47,102
Derivative financial instruments:					
Interest Rate Swaps	2,935	4,113	1,096	-	8,144
Capital Lease Payments	231	260	10	-	501
Other obligations	1,063	516	516	7,681	9,776
Total obligations	$148,429	$ 48,855	$48,428	$ 512,870	$758,582

22. Financial instruments (continued)

Foreign Currency Risk

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

At December 31, 2011, the Company had no outstanding forward foreign exchange contracts. As at December 31, 2010, APUC had outstanding foreign exchange forward contracts to sell US$3,000 at an average rate of $1.00 and having a fair value liability of $45.

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

In connection with the project debt at the St. Leon facility which was repaid during 2011, APCo previously entered into an interest rate swap to hedge the floating interest rate on the project debt. Under the terms of the swap, the Company pays a fixed interest rate of 4.47% on a notional amount of $67.8 million and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2011, the estimated fair value of the interest rate swap was a liability of $6,975 (2010 –liability of $5,440). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

Market Risk

APUC provides energy requirements to various customers under contract at fixed rates. While the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In January 2011, APUC entered into electricity derivative contracts with Nextera (“counterparty”) for a term ending February 2014, which are net settled fixed-for-floating swaps whereby APUC will pay a fixed price and receive the floating or indexed price on a notional quantity of 162,128 MW-hrs of energy over the remainder of the contact term at an average rate of approximately $51.40 per MW-hr. The estimated fair value of these forward energy hedge contracts at December 31, 2011 was a net liability of $1,169 (December 31, 2010 - $nil).

23. Capital disclosures

The Company views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

The Company's objectives when managing capital are:

- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital.
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets.
- To ensure generation of cash is sufficient to fund sustainable distributions to Unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

The Company monitors its cash position on a regular basis to ensure funds are available to meet current operating as well as capital expenditures. In addition, the Company regularly reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

24. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

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Corporate Information

Directors

Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.
Christopher Ball – Executive Vice-President, Corpfinance International Ltd.
Christopher Huskilson – President & Chief Executive Officer, Emera Inc.
Chris Jarratt – Vice-Chair, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
George Steeves – Principal, True North Energy

The Management Group

Ian Robertson, Chief Executive Officer
Chris Jarratt, Vice-Chair
David Bronicheski, Chief Financial Officer

Head Office

2845 Bristol Circle
Oakville, Ontario, L6H 7H7
Telephone – 905-465-4500
Fax – 905-465-4514
Website – www.algonquinpowerandutilities.com

Registrar And Transfer Agent

Canadian Stock Transfer Company Inc.
320 Bay Street, B1 Level
Toronto, Ontario, M5H 4A6

Auditors

KPMG LLP
Toronto, Ontario

Stock Exchange

The Toronto Stock Exchange:
AQN, AQN.DB.B

Legal Counsel

Blake, Cassels & Graydon LLP

2845 Bristol Circle
Oakville, Ontario
Canada L6H 7H7

Tel: 905-465-4500
Fax: 905-465-4514

www.algonquinpower.com

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.03) Federal income tax reconciliation for the test year;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.04) Detailed computation of New Hampshire and federal income tax factors on the increment of revenue needed to produce a given increment of net operating income;

Waiver requested

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.05) Detailed list of charitable contributions charged in the test year showing donee and amount;

See 1604.01(a) (26).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.06) List of advertising charged in the test year above the line showing expenditure by media and by subject matter;

See 1604.01(a) (26).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.07) The utility's most recent cost of service study;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.08) The utility's most recent construction budget;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.09) The utility's chart of accounts, if different from the uniform system of accounts established by the commission as part of Puc 300, Puc 400, Puc 500, Puc 600 and Puc 700;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.10) The utility's Securities and Exchange Commission 10K forms and 10Q forms, for the most recent 2 years;

Please see the attached for copies of Algonquin Power & Utilities Corp.'s Form 40-F to the United States Securities and Exchange Commission for the years ended December 31, 2010 and 2011.

AQN 40-F 12/31/2010

Section 1: 40-F (FOR THE FISCAL YEAR ENDED DECEMBER 31, 2010)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

[Check one]

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

Commission File Number 000-53808

ALGONQUIN POWER & UTILITIES CORP.
(Exact name of Registrant as specified in its charter)

N/A
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

1600
(Primary Standard Industrial Classification Code Number (if applicable))

N/A
(I.R.S. Employer Identification Number (if applicable))

2845 Bristol Circle
Oakville, Ontario
L6H 7H7, Canada
(905) 465-4500
(Address and telephone number of Registrant's principal executive offices)

C T Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
N/A	N/A

Securities registered or to be registered pursuant to Section 12(g) of the Act.

Common Shares, no par value
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

N/A
(Title of Class)

For annual reports, indicate by check mark the information filed with this form:

☒ **Annual Information Form** ☒ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

As of December 31, 2010, there were 95,422,778 Common Shares outstanding.

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the Registrant was required to file such reports); and (2) has been subject to such filing requirements in the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this Chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files) Yes ☐ No ☐

DISCLOSURE CONTROLS AND PROCEDURES

The information provided under the heading "Disclosure Controls" (page 52) contained in the Management's Discussion and Analysis for the fiscal year ended December 31, 2010, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

INTERNAL CONTROL OVER FINANCIAL REPORTING

a. Management's report on internal control over financial reporting

The report of management on Algonquin Power & Utilities Corp.'s internal control over financial reporting provided under the heading "Management's Report" (page 2) in the Audited Annual Financial Statements for the fiscal year ended December 31, 2010, filed as Exhibit 99.2 to this annual report on Form 40-F is incorporated by reference herein.

b. Auditor's attestation report on internal control over financial reporting

The attestation report of KPMG LLP, the independent registered public accounting firm of Algonquin Power & Utilities Corp., on the Company's internal control over financial reporting as of December 31, 2010, is provided herein as Exhibit 99.4 of this annual report on Form 40-F.

c. Changes in internal control over financial reporting

The information provided under the heading "Internal controls over financial reporting" (page 52) contained in the Management's Discussion and Analysis for the fiscal year ended December 31, 2010, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

AUDIT COMMITTEE FINANCIAL EXPERTS

Algonquin Power & Utilities Corp.'s board of directors has determined that it has three audit committee financial experts serving on its audit committee. Christopher Ball, Kenneth Moore and George Steeves have been determined to be such audit committee financial experts and are independent, as that term is defined by the Toronto Stock Exchange's listing standards applicable to Algonquin Power & Utilities Corp. The SEC has indicated that the designation of Christopher Ball, Kenneth Moore and George Steeves as audit committee financial experts does not make any of them an "expert" for any purpose, impose any duties, obligations or liability on Christopher Ball, Kenneth Moore and George Steeves that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee or board of directors.

CODE OF ETHICS

Algonquin Power & Utilities Corp. has adopted a code of ethics (the "Code of Conduct") that applies to all employees and officers, including its Chief Executive Officer and Chief Financial Officer and Chief Accounting Officer. The Code of Conduct is available without charge to any shareholder upon request to Kelly Castledine, Telephone: (905) 465-4500, E-mail: apif@algonquinpower.com, Algonquin Power & Utilities Corp., 2845 Bristol Circle, Oakville, Ontario, L6H 7H7.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information provided under the heading "Pre-Approval Policies and Procedures" (page 77) contained in Algonquin Power & Utilities Corp.'s Annual Information Form (dated March 31, 2011), filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein. All audit services, audit-related services, tax services, and other services provided for the year ended December 31, 2010 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

Algonquin Power & Utilities Corp. is not a party to any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on Algonquin Power & Utilities Corp.'s financial condition, results of operations or cash flows.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading "Contractual Obligations" (page 35) as set forth in the Management's Discussion and Analysis for the fiscal year ended December 31, 2010, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

The information provided under the heading "Audit Committee" (page 76) identifying Algonquin Power & Utilities Corp.'s Audit Committee and confirming the independence of the Audit Committee as set forth in Algonquin Power & Utilities Corp.'s Annual Information Form (dated March 31, 2011), filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

CAUTION CONCERNING FORWARD LOOKING STATEMENTS

Certain statements included in this annual report on Form 40-F and the exhibits attached hereto contain forward-looking information within the meaning of the United States Private Securities Litigation Reform Act of 1995 and applicable Canadian securities legislation. These statements reflect the views of Algonquin Power & Utilities Corp. with respect to future events, based upon assumptions relating to, among others, the performance of Algonquin Power & Utilities Corp.'s assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of Algonquin Power & Utilities Corp., its future plans and its dividends to shareholders. Statements containing expressions such as "outlook", "believes", "anticipates", "continues", "could", "expect", "may", "will", "project", "estimates", "intend", "plan" and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require Algonquin Power & Utilities Corp. to make assumptions and involve inherent risks and uncertainties. Algonquin Power & Utilities Corp. cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that Algonquin Power & Utilities Corp.'s actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the volatility of world financial markets; the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; the state of the Canadian and the United States economies and accompanying business climate as well as those risk factors discussed or referred to in the Management's Discussion and Analysis for the fiscal year ended December 31, 2010, filed as Exhibit 99.3 to this annual report on Form 40-F and Algonquin Power & Utilities Corp.'s Annual Information Form (dated March 31, 2011), filed as Exhibit 99.1 to this annual report on Form 40-F. Algonquin Power & Utilities Corp. cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Algonquin Power & Utilities Corp. reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin Power & Utilities Corp. believes that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of these dates. Algonquin Power & Utilities Corp. is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

UNDERTAKING

Algonquin Power & Utilities Corp. undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

Algonquin Power & Utilities Corp. previously filed with the Commission a written irrevocable consent and power of attorney on Form F-X.

Any change to the name or address of the agent for service of Algonquin Power & Utilities Corp. shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin Power & Utilities Corp.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: March 31, 2011

By:	/s/ David Bronicheski
Name:	David Bronicheski
Title:	Chief Financial Officer

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the year ended December 31, 2010
99.2	Audited Annual Financial Statements for the year ended December 31, 2010
99.3	Management's Discussion & Analysis for the year ended December 31, 2010
99.4	Report of KPMG LLP, Chartered Accountants, on Internal Control Over Financial Reporting
99.5	Consent Letter from KPMG LLP Chartered Accountants
99.6	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.7	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
99.8	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.9	Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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Section 2: EX-99.1 (ANNUAL INFORMATION FORM FOR THE YEAR ENDED DECEMBER 31, 2010)

Exhibit 99.1

ALGONQUIN POWER & UTILITIES CORP.

ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 31, 2011

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*All information contained in this Annual Information Form (“**AIF**”) is presented as at March 31, 2011, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.*

1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. (“**APUC**” or the “**Corporation**”) was originally incorporated under the *Canada Business Corporations Act* (“**CBCA**”) on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the corporation amended its articles to change its name to Societe Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the corporation, among other things, created a new class of common shares (the “**Common Shares**”) and changed its name to Algonquin Power & Utilities Corp. The head and principal office of APUC is located at 2845 Bristol Circle, Oakville, Ontario, L6H 7H7.

APUC is continuing the business of Algonquin Power Income Fund (“**Algonquin**” or the “**Fund**”). APUC’s principal holdings are its trust units (“**Trust Units**”) of Algonquin Power Co. (“**APCo**”), shares of Liberty Water Co. (“**Liberty Water**”) and shares of Liberty Energy Utilities Co. (“**Liberty Energy**”).

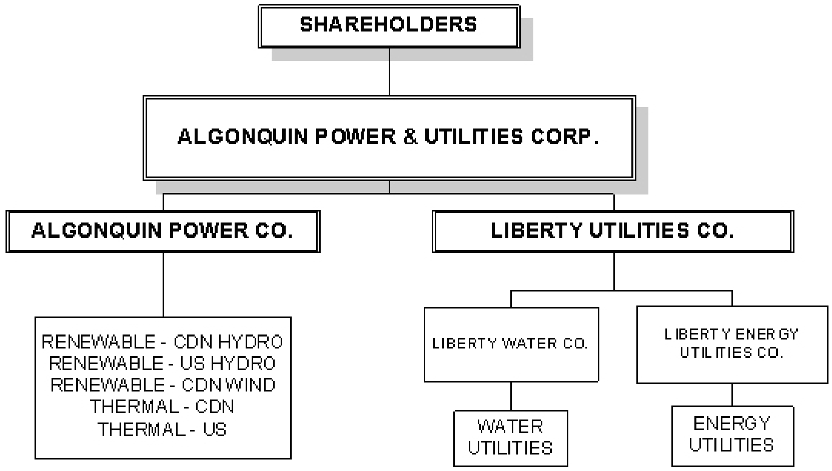
Unless the context indicates otherwise, references in this AIF to “**APUC**” include, for reporting purposes only, the direct or indirect subsidiaries of APUC and partnership interests held by APUC and its subsidiaries. Such use of “**APUC**” to refer to these other legal entities and partnership interests does not constitute a waiver by APUC or such entities or partnerships of their separate legal status, for any purpose.

1.2 Intercorporate Relationships

(a) Subsidiaries

The subsidiaries of APUC are grouped into the independent power generation and the utilities businesses. The principle holding for APUC’s independent power generation business is an investment in 100% of the issued and outstanding Trust Units of APCo. The principle holding for APUC’s utilities business is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp., a federal corporation, which in turn owns all of the issued and outstanding common shares of Liberty Utilities, a Delaware corporation, which in turn owns both Liberty Water and Liberty Energy. Each of APCo, Liberty Water and Liberty Energy have their own subsidiaries and ownership chains.

The subsidiaries of APCo include the ownership chains of Algonquin Power Trust (“**APT**”), Algonquin Power Operating Trust (“**APOT**”), Algonquin Power Fund (Canada) Inc. (“**APFC**”) and Algonquin Power Fund (America) Inc. (“**APFA**”). The Liberty Energy chain is currently structured to hold the electric utility assets located in California and acquired January 1, 2011, and the Liberty Water chain is structured to hold the water and wastewater assets located in the United States. These major chains are defined and shown in the chart below, and a detailed description of the legal entities that comprise these chains and the Facilities they own is then provided. Additional information on the Facilities is described in Schedules A, B, C and D.



(i) APCo Chain Entities

APCo is the sole beneficiary of APT, which owns all the Trust Units of APOT. APT is an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. APT controls the entities that own some of the Canadian hydroelectric facilities, and the energy-from-waste facility (the "**EFW Facility**") located in the Regional Municipality of Peel, Ontario ("**Peel**"). APOT is an unincorporated open ended trust created by an amended and restated trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta. APOT controls the entities that own the Canadian cogeneration facility located at Brampton, Ontario (the "**BCI Facility**"), the wind facility located at St. Leon, Manitoba (the "**St. Leon Facility**"), one hydroelectric facility in Alberta (the "**Dickson Dam Facility**") and APCo's 50% interest in the Alberta biomass facility (the "**Valley Power Facility**"). APCo also owns Algonquin Holdco Inc., an Ontario corporation, which owns APFC. APFC was incorporated in Nova Scotia and it controls the entities that own the majority of the hydroelectric facilities in Canada. APFC also owns APFA, a Delaware corporation, which is the top APCo entity in the United States. APFA owns and controls the U.S. hydroelectric entities, and also controls the entities that own the U.S. thermal cogeneration facilities known as the Sanger Facility and the Windsor Locks. Facility

(ii) APT Group

APT forms part of the APCo business unit and indirectly owns the EFW Facility in the city of Brampton located in Peel by virtue of owning all the Trust Units in KMS Power Income Fund, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997 in accordance with the laws of the Province of Alberta. This trust owns Algonquin Power Energy From Waste Inc. ("**APEFW**"), an Ontario corporation that owns the EFW Facility.

APT also holds interests in certain of APCo's Canadian hydroelectric Facilities. It directly owns the hydroelectric Hydraska Facility and the Arthurville Facility , and owns both the general partnership and the limited partnership interests in Algonquin Power (Campbellford) Limited Partnership

("**Campbellford LP**"), an Ontario limited partnership which operates a 4 megawatt ("**MW**") hydroelectric generation station on the Trent River near Campbellford, Ontario (the "**Campbellford Facility**"). It also holds a 42% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership (the "**Mont-Laurier Partnership**"), a Québec limited partnership, which owns the Mont-Laurier and the Côte Ste.-Catherine Facilities. APEFW owns the remaining 58% partnership interests, comprised of a 46.5% limited partnership interest and an 11.5% general partnership interest.

APT owns Corporation D'Investissements Éoliennes Algonquin Power ("**Éoliennes**"), a Canadian corporation. Éoliennes indirectly owns St. Ulric Wind Energy Investments L.P. ("**St. Ulrich LP**"), a Québec limited partnership, through its ownership of the limited partnership of St. Ulrich LP, (Société en Commandite Algonquin (Éoliennes), a Québec limited partnership, and its direct ownership of the general partner of St. Ulrich LP, named Corporation D'Investissements Éolienes St-Laurent Inc. ("**Corporation St-Laurent**"), a Québec corporation. Corporation St-Laurent Inc. is the 50% owner of Saint-Damase Wind Energy Fleur de Lis General Partner Corporation, a federal corporation, which is the general partner of the partnership known as Saint-Damase Wind Energy Fleur de Lis Limited Partnership ("**Fleur de Lis LP**"). Fleur de Lis LP has an interest in the Saint - Damase wind energy project and described below in "*Power Generation - New Wind Projects Under Development*". St. Ulrich LP owns a 49.995% equity interest in the Fleur de Lis LP, the general partner owns a .02% equity interest, and a non-Algonquin, Saint-Damase party owns the remaining 49.995% equity interest. APT also has an interest in Société Éoliennes Belle- Rivière, société en commandite ("**Belle Rivière**"), a Quebec partnership and the owner of the Val- Éo wind energy project, also described below in "*Power Generation - New Wind Projects Under Development*". It owns a 25% equity interest in the general partner, 9231-5498 Québec Inc. and it also holds a 24.9975% limited partner interest.

(iii) APOT Group

The APOT entities that own the BCI Facility are Brampton Cogeneration Limited Partnership, an Ontario partnership, the partners of which are Brampton Cogeneration Inc. ("**BCI**"), which is the general partner and holds one general partnership unit, and APOT, which owns 100% of the Class A Units (entitled to vote on all matters) and 50% of the Class B Units (vote on only specific matters) in the limited partnership. BCI is an Ontario corporation and is owned by APOT.

The APOT entity that owns the St. Leon Facility is St. Leon Wind Energy LP, an Ontario partnership ("**St. Leon LP**"). It is owned 26.43% by the general partner, St. Leon Wind Energy GP Inc. ("**St. Leon GP**"), 73.16% by St. Leon Wind Energy Trust, a Manitoba trust ("**St. Leon Trust**") and 0.42% by AirSource Power Fund I LP, a Manitoba limited partnership ("**AirSource**"). St. Leon LP has issued 100 Class B limited partnership units. Two executives of APUC, Ian Robertson and Christopher Jarratt (the "**Senior Officers**") indirectly each own 18 of the 100 Class B units. St. Leon Trust is owned 100% by AirSource, the limited partner of which is Algonquin (AirSource) Power LP ("**AAP LP**") which holds a 99.99% interest in the limited partnership, and which in turn is owned 99.99% by APOT as limited partner. AirSource is also the 100% owner of St. Leon GP. St. Leon GP is a Canadian corporation and St. Leon Trust is a trust created by a declaration of trust dated June 28, 2005 in accordance with the laws of the Province of Manitoba. The AirSource and AAP LP limited partnerships were formed in Manitoba and Ontario, respectively. APOT is also the sole limited partner in St. Leon II Wind Energy LP, a Manitoba partnership, the general partner of which is St. Leon II Wind Energy GP Inc. which is also owned by APOT.

APOT also owns Loyalist Wind Project GP Inc., an Ontario corporation, which is the general partner of Loyalist Wind Project LP ("**Loyalist LP**"), an Ontario limited partnership. APUC is the majority limited partner of Loyalist LP, holding a 87.49125% interest. The remaining limited partner of Loyalist LP is an unrelated third party, holding a 12.49875% interest.

APOT has two ownership interests in Alberta. First, it is the beneficial owner of the Dickson Dam Facility. Second, it owns 50% of Valley Power Corp., an Ontario corporation, which holds a 0.0001% limited partnership interest partner in Valley Power LP, an Alberta limited partnership which owns the Valley Power Facility. APOT directly holds a further 49.9995% limited partnership interest in Valley Power LP.

(iv) APFC Group

In Ontario, APFC directly owns the Burgess and Hurdman Facilities, and has an agreement in place to buy ownership interests in the parties to the joint venture that owns the interests in the Long Sault Rapids Facility. In Québec, APFC directly owns the facilities known as Rawdon, Hydro Snemo, St. Raphael, Belleterre and St. Brigette Facilities. APFC also holds a direct interest in Société Hydro-Donnacona, S.E.N.C. (the "**S.E.N.C.**"), the owner of the Donnacona Facility. The S.E.N.C. is a Québec general partnership, and is owned as to 99.99% by APFC and 0.01% by Donnacona Holdings Inc., an Ontario corporation 100% owned by APFC. In Newfoundland, APFC holds a 45% partnership interest in the Algonquin Power (Rattle Brook) Partnership, a Newfoundland partnership that owns the Rattlebrook Facility. APFC also 100% owns Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

(v) APFA Group

APFA owns Algonquin Power Sanger LLC ("**Sanger LLC**"), a California limited liability company, and Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. These entities own the U.S. cogeneration Sanger and Windsor Locks Facilities. Sanger LLC directly owns 100% of Dyna Fibers Inc., a California corporation that operates a hydro-mulch business at the Sanger Facility site. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA indirectly owns numerous hydroelectric facilities through majority interests ranging from 99.7 to 99.99% in the subsidiaries described in this paragraph, with Algonquin Power Fund (America) Holdco Inc. ("**Algonquin Holdco**"), a Delaware corporation owned by APFA, holding the remaining interests. The New York general partnerships Burt Dam Power Company and Hollow Dam Power Company own the Burt Dam and Hollow Dam Facilities, respectively. The Vermont partnership Moretown Hydro Energy Company owns the Moretown Facility. The New Hampshire limited partnerships Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro Associates Limited Partnership and Mine Falls Hydroelectric Limited Partnership own the Gregg Falls, Pembroke and Mine Falls Facilities, respectively.

APFA owns the New Hampshire limited liability company Clement Dam Hydroelectric, LLC which owns the Clement Dam Facility. The Franklin, Beaver Falls, Lakeport and Milton Facilities are owned by, respectively, Franklin Power, LLC, a New Hampshire company, Algonquin Power (Beaver Falls) LLC, a Delaware corporation, Lakeport Hydroelectric Corp., a New Hampshire corporation, and SFR Hydro Corporation, a New Hampshire company. The Otter Creek and Kings Falls Facilities are owned by Tug Hill Energy, Inc. a New York corporation, which is owned by Court Street Investments, Inc. ("**Court Street**"), a Massachusetts corporation, which in turn is owned 100% by APFA. Court Street also owns CSI Oswego Corp., a Delaware corporation, which is a partner in Oswego Hydro Partners L.P., the Delaware partnership that owns the Phoenix Facility. The other partner in this partnership is Oswego Energy Corp., a Delaware corporation, which is 100% owned by Oswego Power Company, Inc., a Massachusetts corporation, which in turn is 100% owned by APFA. The remaining hydroelectric facilities in the United States are the Great Falls and Lochmere Facilities. The Great Falls Facility is owned by the Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership in which APFA holds a 98% limited partner interest. Great Falls Energy, LLC holds the remaining 2%

general partner interest. Great Falls Energy, LLC is a Maryland limited liability company wholly owned by APFA. The Lochmere Facility is owned by the Indiana general partnership HDI Associates I, which is held 1% by Algonquin Holdco and 99% by APFA.

APFA, in January 2010, 100% acquired two entities, now known as Algonquin Tinker Gen Co. ("**Tinker Gen Co.**") and Algonquin Northern Maine Gen Co. ("**Northern Maine Gen Co.**"), both Wisconsin companies. Tinker Gen Co. is also registered in New Brunswick, and Northern Maine Gen Co. is also registered in Maine. Tinker Gen Co. leases the 36.8MW of electrical generating assets in New Brunswick (the "**Tinker Assets**") from APT, and Northern Maine Gen Co. is the owner of the Caribou, Squa Pan and Flos Inn hydro, diesel and steam Facilities. APFA also 100% owns Algonquin Energy Services Inc., a Delaware corporation ("**AES**") that is also registered in Connecticut, District of Columbia, Maine, Maryland, New Brunswick and Ohio. AES's business primarily involves providing the electrical energy requirements for commercial and industrial customers in northern Maine. On February 4, 2010, AES acquired a number of load supply and energy procurement contracts in northern Maine and the Independent System Operator New England ("**ISO-NE**") market (the "**Energy Services Business**"). See "*Significant Acquisitions*" in "*General Development of the Business"* and "*Energy Services Business*" in "*Description of the Business*".

In addition, APFA owns 100% of Algonquin Power Acquisition Inc., a Delaware corporation that was incorporated as an acquisition vehicle for proposed acquisitions by APCo in the United States. It currently has no assets. APFC also 100% owns Algonquin Power Services America LLC, a Delaware corporation that provides purchasing services to U.S. APCo entities.

(vi) Liberty Water Group

On December 22, 2010, APCo completed a corporate reorganization involving Liberty Water wherein 100% of the issued and outstanding common shares of Liberty Water were transferred to APUC at their estimated fair market value which approximated the book value of the shares. Liberty Water was originally formed under the laws of the state of Delaware as Algonquin Water Resources of America, Inc. The name was changed on April 28, 2009 to Liberty Water Co. Liberty Water Co. forms the top of the Liberty Water Group and indirectly owns the water and wastewater businesses located in Arizona, Texas, Missouri and Illinois, in each case through a 100% wholly-owned subsidiary, with the exception of the Entrada Del Oro Sewer Company, Inc. ("**Entrada**") in which it currently operates and holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition by Liberty Water. All of these 100% wholly-owned subsidiaries (except Northwest Sewer, Inc.) are currently conducting business as "**Liberty Water**"; however the actual legal names of the relevant entities are set out below.

In Arizona, the following Arizona corporations own the following facilities: Bella Vista Water Co., Inc. owns the Bella Vista Facility; Black Mountain Sewer Corporation owns the Black Mountain Facility; Gold Canyon Sewer Company owns the Gold Canyon Facility; Litchfield Park Service Company owns the Litchfield Facility; Northern Sunrise Water Company, Inc. owns the Northern Sunrise Facility; Rio Rico Utilities, Inc. owns the Rio Rico Facility; and Southern Sunrise Water Company, Inc. owns the Southern Sunrise Facility. Northwest Sewer, Inc., an Arizona corporation, has undertaken to a group of developers and homeowner's associations located to the west of Phoenix to apply for a Certificate of Convenience and Necessity and, if successful, operate a wastewater treatment utility in those areas. Entrada, discussed above, is an Arizona corporation, and it owns the beneficial interest in the Entrada Del Oro Facility. In Texas, the following Texas corporations own the following facilities: Tall Timbers Utility Company, Inc. owns the Tall Timbers Facility; Woodmark Utilities, Inc. owns the Woodmark Facility; and Algonquin Water Resources of Texas, LLC, a Texas limited liability company, owns water and water treatment assets at the resorts of Galveston, Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as "Big Eddy"). In Missouri, Algonquin Water Resources of Missouri, LLC, a

Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain and Timber Creek resorts. In Illinois, Algonquin Water Resources of Illinois, LLC, an Illinois limited liability company, owns assets for the Fox River resort. All water and wastewater utilities are operated under the Liberty Water brand.

In addition, Algonquin Water Services LLC ("**Water Services**") is a company established to manage and operate water distribution and wastewater treatment facilities in Arizona and Texas. It is an Arizona limited liability company owned 99% by New Spring Acquisition Partnership, an Ontario partnership, which in turn is owned 50% by APCo. Algonquin Environmental Services LLC, a Delaware limited liability company owned 100% by Liberty Water, was also established to service various entities.

(vii) Liberty Energy Group

Liberty Energy is a Delaware corporation. It owns 50.001% of California Pacific Utilities Ventures, LLC, a California limited liability company ("**CPUV**"), which in turn owns California Pacific Electric Company, LLC, a California limited liability company ("**Calpeco**"). Effective January 1, 2011, Calpeco acquired the California-based electricity distribution and related generation assets of NV Energy, Inc. ("**NV Energy**"). See "*Significant Acquisitions*". Liberty Energy also owns Liberty Energy Utilities (New Hampshire) Corp. ("**Liberty Energy NH**"), a Delaware corporation registered in New Hampshire. Liberty Energy NH is the named purchaser of the shares of Granite State Electric Company ("**Granite State**") and EnergyNorth Natural Gas Inc. ("**EnergyNorth**") currently owned by for the assets of National Grid USA ("**National Grid**").

(viii) Other

Outside of the APCo, Liberty Water and Liberty Energy chains described above, APUC beneficially owns, directly or indirectly 100% of the following: 3793257 Canada Inc. ("**3793257**"), a corporation incorporated under the CBCA; and Windlectric Inc. ("**Windlectric**"), a federal corporation that is developing the Amherst Island wind project, described below in "*Power Generation - New Wind Projects Under Development*".

(b) Other Interests in Energy Related Developments

The Corporation also has notes receivable and equity in companies owning generating facilities as described below. APT owns 25% of the Class B non-voting shares issued by Cochrane Power Corporation, the owner of a combined cycle cogeneration facility located in Cochrane, Ontario. APT also owns 32.4% of the Class B non-voting shares in Kirkland Lake Power Corporation, an entity which burns natural gas and wood waste to generate electricity. APT also owns a 12.1% interest in Tranche A and Tranche B term loan interests issued by Chapais Energie, Société en Commandité ("**Chapais**") which owns a wood waste facility in Chapais, Québec. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais. The loans bear interest at the rate of 10.789% and 4.91%, respectively.

In addition, APUC is entitled to a royalty in the form of cash flows generated by the Long Sault Rapids Facility (the "**LSR Royalty Interest**"). It is also the owner of a 14.14% secured, subordinated note (the "**LSR Subordinate Note**") in the principal amount of $2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc. The LSR Subordinate Note was acquired by the Fund on April 17, 1998.

2. GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

(a) The Unit Exchange

On October 27, 2009, Algonquin completed a transaction (the "**Unit Exchange**") in which Algonquin's unitholders exchanged their trust units of Algonquin, on a one-for-one basis, for Common Shares of an existing corporation. As a result of the Unit Exchange, the Fund itself became a wholly-owned subsidiary of the Corporation and all of the unitholders of the Fund became shareholders of the Corporation. The Unit Exchange did not result in any change to the underlying business operations of the Fund and accordingly, for accounting purposes, the Corporation is considered a continuation of the Fund. The Fund has since changed its name to Algonquin Power Co.

(b) Business Strategy

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the power and utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through growth in dividends supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon APUC strives to deliver annualized per share earnings growth of 5% and to grow its dividend supported by growth in cash flows, earnings and investment prospects.

APUC understands the importance of the dividend to its shareholders. In the fiscal year ended December 31, 2010, APUC paid quarterly cash dividends to shareholders of $0.06 per share or $0.24 per share per annum. On March 3, 2011, the board of directors of APUC (the "**Board**") approved an annual dividend increase of $0.02 per common share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per common share. The Board also declared a dividend of $0.065 per share payable on April 15, 2011 to the shareholders of record on March 31, 2011.

APUC believes this level of dividends will continue to allow for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Any increases in the level of dividends paid by APUC will be at the discretion of the Board and dividend levels shall be reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to the Corporation. APUC strives to achieve its results within a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC produces stable earnings through a diversified portfolio of renewable power and utility businesses owned and operated by its subsidiary entities. APUC conducts its operations primarily through two businesses: independent power generation and utilities (water, gas and electric). These businesses of APUC are herein referred to as the "**APUC Businesses**".

Independent Power Generation: APCo develops, owns and operates a diversified portfolio of electrical energy generation facilities. Within this business there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates APCo's hydroelectric and wind power facilities. The Thermal Energy division operates co-generation, energy-from-waste, and steam production facilities. The Development division seeks to deliver continuing growth to APCo through development of APCo's greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within APCo's existing portfolio of renewable energy and thermal energy facilities.

The renewable power and thermal energy generation business of APCo is managed with an emphasis on growth through the development of green-field projects and opportunities within APCo's existing portfolio. This involves building on APCo's expertise in the origination of greenfield renewable energy projects, expanding APCo's existing portfolio of assets for further growth, and capitalizing on new opportunities as they arise.

APCo's Renewable Energy division generates and sells electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. As at March 15, 2011, APCo owns or has interests in 44 hydroelectric facilities operating in Ontario (4), Québec (12), Newfoundland (1), New Brunswick (1) Alberta (1), New York State (13), New Hampshire (8), Vermont (1), Maine (2) and New Jersey (1) with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds debt securities in a 26 MW wind powered generating station recently completed in Saskatchewan. Approximately 75% of the installed capacity of APCo's renewable energy facilities sell their electrical output pursuant to long term power purchase agreements ("**PPA**s") with major utilities and have a weighted average remaining contract life of 16 years.

APCo's Thermal Energy division holds equity interests in one energy-from-waste facility in Ontario with an installed generating capacity of 10 MW, 4 diesel generating facilities in Maine and New Brunswick with total installed generating capacity of 34 MW and 3 natural gas-fired cogeneration facilities in each of California, Connecticut, and Ontario with an installed capacity of approximately 112 MW. In addition, APCo's Thermal Energy division owns partnership, share and debt interests in two biomass-fired generating facilities with combined installed capacity of approximately 43 MW located in Alberta and Québec. APCo's Thermal Energy division holds minority investments in two natural gas/wood waste-fired generating facilities with joint installed capacity of approximately 170 MW located in northern Ontario. APCo's ownership interest in the combined installed generating capacity represents approximately 210 MW. APCo's thermal energy facilities operate under long term PPAs with major utilities and have an average remaining contract life of 6 years. Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

Utilities: Liberty Utilities Co. ("**Liberty Utilities**") owns and operates utilities through its two wholly-owned subsidiaries, Liberty Energy and Liberty Water. Liberty Energy is in the electricity distribution, transmission and generation sector as well as natural gas distribution. Liberty Water is in the water distribution and wastewater treatment sector. These utilities share certain common infrastructure to generate economies of scale to support best-in-class customer care for its utility ratepayers. The underlying business strategy is to be a leading provider of safe, high quality and reliable utility services while providing stable and predictable earnings from utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings by identifying acquisition opportunities which provides accretive expansion of its business portfolio.

Liberty Utilities' water utility division operates under the name of Liberty Water. Liberty Water provides water and wastewater utility services to approximately 74,000 customers through 19 water distribution and wastewater collection and treatment utility systems located in four U.S. States (Arizona (8), Illinois (1), Missouri (3) and Texas (7)). These utilities generally operate under rate regulation, overseen by the public utility commissions of the States in which they operate. Detailed information on the water distribution and wastewater utility systems owned and operated by Liberty Water is set out in Schedule C.

In 2009, APUC branded all of its water and wastewater utilities under the Liberty Water brand. Liberty Water is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Water delivers long term value by profitably owning and operating water and wastewater utilities while providing safe, reliable transportation and delivery of water and wastewater treatment in its service areas. It is also focused on delivering continued growth in earnings by identifying opportunities which accretively expand its business portfolio.

Liberty Utilities' energy utility division operates under the name of Liberty Energy. Liberty Energy provides local electrical and natural gas utility services. On January 1, 2011, Liberty Energy acquired a 50.001% interest in a California-based electricity distribution utility and related generation assets, and now provides electric distribution service to customers in the Lake Tahoe region (the "**California Utility**"). Liberty Energy has entered into agreements to acquire two additional utilities which currently provide electric and natural gas distribution services to customers in New Hampshire. Detailed information on the electrical utilities systems owned and operated by Liberty Energy is set out in Schedule D.

2.2 Three Year History

The following is a description of the general development of the business of the Corporation over the last three fiscal years.

(a) Fiscal 2008

On January 16, 2008, the Fund renewed its combined $175.0 million senior secured revolving operating and acquisition credit facility (the "**Senior Credit Facility**") with a syndicate of Canadian banks. Under terms of the renewal, the Senior Credit Facility was extended for a three year term with a maturity date of January 14, 2011. The renewal included improved pricing and other terms as well as an accordion feature that, subject to certain conditions, allowed the Senior Credit Facility to increase to $225.0 million to accommodate future growth and acquisitions. The Fund subsequently exercised a portion of the accordion feature, resulting in total committed and available Senior Credit Facility of $192.8 million.

In June 2008, the BCI Facility was commissioned and became operational. The project involved diverting the existing steam produced by the EFW Facility to a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities. BCI was established to supply steam produced through normal operations at the EFW Facility to this mill.

On June 27, 2008, the Fund entered into a business combination agreement (the "**Business Combination Agreement**") with Highground Capital Corporation ("**Highground**") and CJIG Management Inc. ("**CJIG**"), the manager of Highground and a related party of the Fund controlled by the shareholders of Algonquin Power Management Inc. ("**APMI**"). APMI was the manager of APCo up to December 22, 2009 and two executives of APUC, the Senior Executives, are principals of APMI. Pursuant to the Business Combination Agreement, CJIG acquired all of the issued and outstanding common shares of Highground, and the Fund issued approximately 3.5 million Trust Units at an ascribed value of approximately $7.69 per Trust Unit. The trading price of the Trust Units at the time of issue was $7.41. Of these Trust Units, approximately 3.1 million Trust Units were received by shareholders of Highground as part of the Business Combination Agreement, with the remaining Trust Units being retained by CJIG. The Fund recorded the Trust Units issued at the estimated fair value of the assets to be liquidated by Highground which, net of transaction costs of $0.8 million, resulted in proceeds of the Trust Units being recorded at a value of $26.2 million. In connection with this transaction, the Fund received: (a) net cash in an amount of $20.6 million; (b) the return of notes, having an aggregate face value of approximately $4.8 million, that were issued by the Fund affiliates related to its St. Leon and BCI Facilities; and (c) a note receivable of $0.8 million related to a hydroelectric facility in Ontario.

The final consideration for the Trust Units is dependent on the proceeds realized from the liquidation of certain Highground investments. APUC's final consideration will be equal to the lesser of (a) $27.0 million plus 50% of the amount, if any, of the value of the assets formerly owned by Highground after payment of the transaction costs that exceeds $27.0 million and (b) the value of all of the assets formerly owned by Highground after payment of the transaction costs. The value of any non-cash securities received by APUC will be determined through negotiation between the Board and CJIG. The remaining investments, formerly held by Highground, consist primarily of non-liquid debt assets having a book value of approximately $3.2 million. APUC is entitled to 50% of the ultimate proceeds from these investments, after certain adjustments for transaction costs.

(b) Fiscal 2009

On October 27, 2009, the Fund and the Corporation completed the Unit Exchange. See "*The Unit Exchange*". As part of the Unit Exchange, on October 27, 2009, the trustees of the Fund also became directors of APUC.

Also on October 27, 2009, in connection with the Unit Exchange, the debentureholders of the Fund exchanged their convertible debentures for convertible debentures of the Corporation or Common Shares. As a result, the debentureholders of the Fund became debentureholders and shareholders of the Corporation. See "*Capital Structure - Convertible Debentures"*.

On December 2, 2009, APUC completed a public offering of 5,980,000 Common Shares at a price of $3.35 per Common Share for gross proceeds of approximately $20 million and approximately $55 million principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017 (the "**Series 3 Debentures**"). The underwriters of the offering also exercised in full an over-allotment option to purchase an additional 897,000 Common Shares and approximately $8.2 million principal amount of Series 3 Debentures resulting in aggregate gross proceeds of approximately $86.2 million. See "*Capital Structure - Convertible Debentures*".

On December 21, 2009, the board of directions of the Corporation (the "**Board**") reached agreement with the shareholders of APMI to internalize all management functions of the Fund which were provided by APMI. APUC acquired the interest previously held by APMI in the management services agreement, with consideration paid in the form of issuance of 1,158,748 Common Shares.

(c) Fiscal 2010

At the annual general meeting on June 23, 2010 (the "**Meeting**"), APUC adopted a Shareholders' Rights Plan (the "**Rights Plan**"). See "*Capital Structure - Shareholders' Rights Plan"*.

Liberty Water had ongoing rate cases at a number of its utilities which were processed throughout 2010. See "*Utilities: Water and Wastewater - Rate Cases*" for further discussion of the status of these rate cases. During the year ended December 31, 2010, Liberty Water completed rate case proceedings at nine utilities in Arizona and Texas which on an annualized basis were expected to contribute an additional U.S. $10.2 million in revenue in Liberty Water. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. $1.1 million in annual revenue requirement is expected to be concluded by the first quarter of 2011.

On December 22, 2010, Liberty Water completed a private placement financing of senior unsecured 5.6% notes for gross proceeds of approximately U.S. $50 million. The notes have a 10 year term bear interest until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. The funds were used to reduce outstanding indebtedness under the Senior Credit Facility.

2.3 Recent Developments

(a) Power Generation - New Wind Projects Under Development

75 MW Wind - Amherst Island: On February 25, 2011, APUC announced that the Ontario Power Authority ("**OPA**") awarded a contract to the wholly-owned 75 MW Amherst Island Wind Project. The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. The contract was awarded as part of the second round of the OPA's Feed-in Tariff ("**FIT**") program. Construction is expected to commence shortly following the approval of the application and is expected to take 12 months.

(b) Power Generation: Development

25MW Wind - Saint-Damase: The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APUC. The first 24 MW phase of the project currently has a targeted commercial operations date in late 2013.

25 MW Wind - Val-Éo: The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APUC. The first 24 MW phase of the project currently has a targeted commercial operations date of late 2015.

Preliminary permitting began for both projects in early 2011, with all major authorizations targeted for completion by the end of 2012.

20 MW Wind - Morse: On March 21, 2011, APUC announced it has executed an asset purchase agreement with Kineticor Renewables Inc. ("**Kineticor**"), to acquire all of the assets related to two proposed adjacent 10 MW wind energy development projects near Morse, Saskatchewan (the "**Morse Projects**"). The Morse Projects are approximately 180 km west of Regina and 400 km west of the 26.4 MW wind generation facility in southeastern Saskatchewan ("**Red Lily I**").

The Morse Projects were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program in May 2010. Upon SaskPower's approval and execution of the PPAs, Kineticor will assign the PPAs to APCo. The Morse Projects are expected to be completed in late 2013.

The Morse Projects are approximately 180 km west of Regina and 400 km west of the 26.4 MW wind generation facility in southeastern Saskatchewan ("**Red Lily I**"). It is contemplated that the Morse Projects will be situated on 1,120 acres of private lands, with additional land under lease or option in order to facilitate future expansion of the Morse Projects.

For a more detailed description of the current projects under development, see “*Current Development Projects*” and “*Quebec Community Wind Projects*” in the section entitled “*Power Generation: Development*” below.

(c) Power Generation

On February 28, 2011, APUC announced that Red Lily I commenced commercial operation under the SaskPower PPA. The PPA with SaskPower is for 25 years and includes a 2% annual increase throughout the term of the agreement. APUC’s commitment in Red Lily I is structured in the form of senior and subordinated debt investment of approximately $19.6 million bearing a blended interest rate of 8.43%.

Project construction costs at Red Lily I are expected to total $71.2 million. In addition to interest payments on its portion of the debt financing, APUC is entitled to certain supervisory fees, estimated at $1.3 million in the first full year of operation. Total interest and fee payments to APUC in 2011 are estimated to be approximately $2.4 million, representing approximately 75% of the expected net cash flows from Red Lily I. APUC has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest in Red Lily I, exercisable in February 2016.

For a more detailed description of the options and expected impact see “*Red Lily Facility*” under “*Material Facilities*” in the section entitled “*Power Generation: Renewable – Wind Power*” below.

Subsequent to December 31, 2010, the Energy Services Business entered into a three year contract with Maine Public Service Company, a regulated electric transmission and distribution utility serving approximately 36,000 electricity customer accounts in Northern Maine starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with the standard offer service is approximately 135,000 MW-hrs.

The capital upgrade at the EFW Facility, completed in July 2010, is expected to result in higher throughput and lower operating costs at the Facility in the first quarter of 2011 as compared to the same period in 2010 when the Facility was temporarily shut down as a result of an unplanned outage experienced in January 2010.

The Windsor Locks Facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO-NE day-ahead market or to retail customers through the Energy Services Business. The Facility did not commit any portion of its electrical capacity to the forward reserve market for the winter of 2011 due to unacceptably low auction prices. It is anticipated that performance during the first quarter of 2011 will be strong, resulting from moderate natural gas prices and a cold winter in the north-east U.S. that has resulted in high electricity prices. APCo has completed preliminary engineering for a repowering project at the Windsor Locks Facility and is in negotiations with Ahlstrom Windsor Locks, LLC (“**Ahlstrom**”) regarding this project. For a more detailed description of the options and expected impact see “*Windsor Locks*” under “*Material Facilities*” in the section entitled “*Cogeneration*” below.

(d) Senior Credit Facility

On January 14, 2011, APUC announced that it has received commitments from a syndicate of Canadian banks for a new $142 million Senior Credit Facility with a three year term. Under the terms of the new banking agreement, as at December 31, 2010, APCo had $44.4 million of committed and available bank facilities remaining and $5.1 million of cash resulting in $49.5 million of total liquidity and capital reserves. The APCo Senior Credit Facility now matures on February 14, 2014.

As at March 25, 2011, APCo had used the Senior Credit Facility to post (i) a letter of credit in the approximate amount of U.S. $19.5 million in respect of the Sanger Facility; (ii) a $1.0 million letter of credit in respect of the Dickson Dam Facility; (iii) letters of credit for the EFW Facility totalling $5.4 million; (iv) letters of credit pursuant to the BCI Facility totalling $2.3 million; (v) letters of credit in connection with the St. Leon Facility totalling $1.8 million; (vi) letters of credit in connection with the Long Sault Rapids Facility totalling $1.2 million; (vii) letters of credit in connection with the Amherst Island Wind Project totalling $1.5 million; and (viii) various other letters of credit required by APCo entities totalling $1.1 million.

(e) Liberty Water

On December 11, 2010, the Arizona Corporate Commission ("**ACC**") approved an order authorizing a rate increase of U.S. $0.9 million for the Rio Rico Facility, effective February 1, 2011. It is anticipated that the regulatory review of the proposed rates and tariffs for the Bella Vista, Northern Sunrise, and Southern Sunrise Facilities will be completed in Q1 2011. Total revenue increases from rate cases completed in Arizona and Texas represent an additional U.S. $10.2 million in annualized revenue. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year.

(f) Liberty Energy

In 2009, APUC announced plans to acquire the California Utility assets in partnership with Emera Inc. ("**Emera**"). The acquisition was approved by both the California Public Utilities Commission ("**CPUC**") and the Public Utilities Commission of Nevada in the fourth quarter of 2010. The transaction was completed on January 1, 2011 for a purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. The acquisition was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility. Liberty Energy's ownership share of the cost of acquisition of the California Utility was primarily funded through the proceeds of subscription receipts held by Emera for 8.532 million APUC Common Shares at a price of $3.25 per share.

On December 9, 2010 APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State, a regulated electric distribution utility, and EnergyNorth, a regulated natural gas distribution utility for total consideration of U.S. $285.0 million. See "*Significant Acquisitions - Energy Utilities*".

Liberty Energy is pursuing additional investments in electric and gas distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best in-class-customer care for its subsidiary utility ratepayers.

2.4 Significant Acquisitions

(a) Power Generation

On January 12, 2010, APCo completed the acquisition of three hydroelectric generating stations, the 34.5MW Tinker Hydro Facility, a hydroelectric generating facility with sufficient reservoir storage capability to move significant amounts of energy from off-peak to on-peak generation located on the Aroostook River near the Town of Perth-Andover, New Brunswick, Caribou Hydro Facility, a 0.9MW run-of-river hydroelectric generating facility located in Northern Maine and Squa Pan Hydro Facility, a 1.4MW run-of-river hydroelectric generating facility located in Northern Maine.

APCo also acquired five thermal generating facilities with a rated capacity of 40MW in Northern Maine and New Brunswick utilized for installed reserve capacity, not continuous generation, and New Brunswick Public Utilities Board regulated transmission lines and interconnections which allow direct and indirect access to multiple electricity markets (Northern Maine ISA, New Brunswick ISO, ISO-NE).

In connection with the acquisition of the Tinker Assets, on February 4, 2010, APCo acquired the Energy Services Business which markets the energy generated from the Tinker Assets. It is anticipated that the majority of the energy sold by the Energy Services Business will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities. The Energy Services Business primarily involves standard offer contracts for the supply of energy to commercial and industrial customers in northern Maine, as well as energy purchase obligations with the ISO-NE required to supplement self-generated energy.

The Energy Services Business consists of a series of short-term energy supply agreements. These include energy sales to a town in New Brunswick, standard offer service contracts with three local electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine.

(b) Energy Utilities

On April 23, 2009, APUC announced plans to co-acquire an electrical generation and regulated distribution utility in partnership with Emera. APUC and Emera would own 50.001% and 49.999%, respectively, of CPUV, which owns 100% of Calpeco. Calpeco was formed to acquire the California-based electricity distribution and related generation assets of NV Energy for the purchase price of approximately US $132 million, subject to certain working capital and other closing adjustments, as outlined in the asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 (the "**Purchase Agreement**").

In October 2009, an application was filed with the CPUC requesting approval of the transaction in which NV Energy had agreed to sell its California electric distribution and generation assets to Calpeco. The transaction was subject to State and Federal regulatory approval. On January 1, 2011, following receipt of all U.S. State and Federal regulatory approvals, Calpeco acquired the assets comprising the California Utility. The California Utility provides electric distribution service to approximately 48,000 customers in the Lake Tahoe region.

As an element of the California Utility partnership, pursuant to a subscription and unitholder agreement dated April 22, 2009 (the "**Subscription Agreement**"), Emera agreed to a conditional treasury subscription of approximately 8.5 million Trust Units of the Fund at a price of $3.25 per unit. Subsequent to the completion of the Unit Exchange, the Subscription Agreement was amended to reflect a subscription of Common Shares rather than Trust Units of Algonquin. Upon closing, Emera exchanged these subscription receipts into 8.532 million Common Shares at a purchase price of $3.25 per Common Share. The proceeds of the subscription receipts were utilized to fund Liberty Energy's ownership share of the cost of acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility entered into on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors, backed solely by the California Utility assets. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

On December 9, 2010, APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State, a regulated electric distribution utility, and EnergyNorth, a regulated natural gas distribution utility from National Grid for total consideration of U.S. $285.0 million, subject to certain working capital and other closing adjustments, as outlined in the share purchase agreements by and between National Grid and Liberty Energy entered into on December 8, 2010 and amended and restated on January 11, 2011 (the "**Purchase Agreements**").

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011. Financing of the acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Energy is targeting a capital structure with not more than 50% debt to total capital, consistent with investment grade utilities.

As an element of the EnergyNorth and Granite State acquisitions and pursuant to a subscription agreement dated December 9, 2010 (the "**2010 Subscription Agreement**"), Emera has agreed to a conditional treasury subscription of 12.0 million trust units of APUC at a price of $5.00 per Common Share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth.

For complete details on the Purchase Agreement(s) and the Subscription Agreement, reference should be made to the documents as filed on SEDAR at www.sedar.com.

3. DESCRIPTION OF THE BUSINESS

3.1 General Description of the Regulatory Regimes in which the Business Operates.

(a) Power Generation Regulatory Regimes

(i) Canada

In Canada, the provinces have legislative authority over the supply of energy. The majority of the electrical supply within the Canadian provinces is provided by large Crown corporations such as Ontario Power Generation Inc. and Hydro-Québec or smaller, investor-owned utilities. These large utilities have been primarily responsible for the generation, transmission and distribution of electricity.

"**Green Power**" is considered electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. Green Power includes technologies such as small hydroelectric (generally defined as facilities of less than 20 MW in capacity), bioenergy, landfill gas, wind and photovoltaic technologies. Since 1997, both the federal and provincial governments in Canada have provided various incentives to stimulate the production of Green Power in Canada. The incentives have varied from direct subsidies, to tax credits to higher than market rates for electricity generated from renewable energy sources.

Most recently in 2007, the Federal government established a new Renewable Power Production Incentive program ("**RPPI**") called "ecoEnergy for Renewable Power" that was created to stimulate up to 14.3 terawatt hours of other new renewable energy. The RPPI provides for an incentive of $10 per MW-Hr of production for the first ten years of operations for eligible projects commissioned after April 1, 2007 and before March 31, 2011. Eligible technologies include waterpower, advanced, innovative and highly efficient biomass, combustion technologies using biogas and other renewable technologies. The ecoEnergy program is scheduled to be completed by the end of March 2011.

(ii) United States

The power generation industry in the United States is regulated by the United States Federal Energy Regulatory Commission ("**FERC**") under the U.S. Public Utilities Regulatory Policies Act ("**PURPA**"). FERC, pursuant to the PURPA legislation, mandates the development of policies by state utility commissions and utilities themselves that enable private producers to build power facilities. The key policy issue was the development of long term PPAs with fixed, long-term power purchase rates. The long-term rates were based on projections of the utilities' Avoided Costs. "**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator. Today, due to market forces and economic changes, many of these long-term agreements are priced far above current market rates. While these higher costs are burdensome to the utilities, most have recognized these as costs incurred prior to deregulation that can no longer be paid by the rate base due to changes to various factors.

On February 2, 2006, PURPA issued revised rules, *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671, 114 FERC 61,102 (2006). Further regulations were also issued to clarify the regulations and became effective on April 20, 2006. In order to comply with the new regulations, in June of 2006, APUC filed with FERC a notification of holding company status for each direct and indirect subsidiary company of APUC. Based on an initial review of the regulations, APFC may be impacted by the revised rules. APUC is currently investigating the option of filing an exemption or waiver with FERC for APFC.

The key regulations that impact APUC are:

(1) Any type of Qualifying Facility that exists but has never filed a self-certification (or obtained an order certifying it as a Qualifying Facility) must file a self-certification (or petition for an order) within 60 days of Order No. 671. Self-certification documents were filed for all affected APUC Facilities in compliance this regulation.

(2) Any cogeneration Qualifying Facility, any small power production Qualifying Facility less than 30 MW, and any geothermal small power production Qualifying Facility, is now subject to rate regulation under Section 205 and 206 of the *Federal Power Act*. However, sales of energy or capacity made by Qualifying Facilities 20 MW or smaller, or made pursuant to a contract executed on or before March 4, 2006, or made pursuant to a state regulatory authority's implementation of PURPA are exempt from scrutiny under sections 205 and 206. If this exception does not apply, then these Qualifying Facilities must make a rate filing under section 205 of the Federal Power Act in order to be eligible to sell electricity. Rate filings were required to be made on or before the effective date of Order 671, which was March 4, 2006. All relevant APUC facilities had PPAs in place predating this section of the new FERC regulations and as such have not been impacted.

The Obama-Biden *New Energy for America Plan* supports 10% of electricity in the United Sates being generated from renewable sources by 2012 and 25% by 2025. The demand for additional renewable power is also expected to increase from the desire by various government entities to increase infrastructure spending.

(b) Water Utility Services Regulatory Regimes

(i) United States Water Services Industry

Investor-owned utilities are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%.

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is provided a service territory defined by a Certificate of Convenience and Necessity which imposes an exclusive right and duty to serve in the service territory. A Certificate of Convenience and Necessity is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(c) Electrical Utility Services Regulatory Regimes

(i) United States Electric Services Industry

Investor-owned electricity utilities are subject to regulation by the public utility commissions of the States in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%.

Generally, electricity providers in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the electric services company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

The electricity industry remains perhaps the most highly regulated in the United States. The industry is regulated under strict standards at multiple levels - federal, state and sometimes local. Under the Federal

Power Act, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability. This oversight also includes cost-of-service regulation to establish rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs in order to determine the revenue requirement upon which each utility's customer rates are set. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure reliable service and adequate supplies of electricity together with financial security, transparency in the rate setting process and reasonable prices.

3.2 Production Method, Principal Markets, Distribution Methods and Material Facilities

(a) Power Generation: Renewable - Hydroelectric

(i) Production Method

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as "head"), as well as to provide sufficient depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a headpond.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner. The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

(ii) Principal Markets and Distribution Methods

The principal markets of in Canada are Alberta, Ontario, New Brunswick and Québec. In the US, the principal markets are Maine, New York State and New Hampshire. The majority of generated hydroelectricity is conveyed from the relevant APCo facility to the purchasers under the terms of long term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser. A summary of the PPAs for APCo's Renewable Energy division is set out in Schedule A.

(1) Alberta

Electrical power generators in Alberta are regulated by the *Electric Utilities Act (Alberta)* and the *Independent Power and Small Power Regulation*.

(2) Ontario

The Ontario government develops the regulatory framework for wholesale and retail competition through the Ontario Energy Board (the "**OEB**"). While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

The Ontario Electricity Financial Corporation ("**OEFC**") holds all rights, obligations and liabilities under such PPAs. This Ontario government agency purchases the energy generated by the Ontario facilities in which APCo has an interest pursuant to the existing contracts. APCo has also received a licence to generate from the OEB as required by the *Energy Act (Ontario)*.

(3) New Brunswick and Northern Maine

In 2003 the New Brunswick government amended the provincial *Electricity Act (New Brunswick)* (the "**Electricity Act**") which resulted in the start of competition in the generation business.

As a result of the Electricity Act, which took effect in October of 2004, New Brunswick Power Corporation ("**NB Power**") was divided into separate businesses with the aim of selling off the various components. The distribution and customer service division of NB Power now functions as a regulated monopoly and serves all the residential and industrial power consumers in the province, with the exception of those in Saint John, Edmundston and Perth-Andover which are served by Saint John Energy, City of Edmundston Electric and the Perth-Andover Electric Light Commission, respectively.

One of the separate entities created by the Electricity Act is the New Brunswick System Operator ("**NBSO**"), an independent not-for-profit statutory corporation. NBSO is responsible for the adequacy and reliability of the integrated electricity system, and for facilitating the development and operation of the New Brunswick electricity market. These responsibilities take the form of operation of the NBSO-controlled grid and administration of the Open Access Transmission Tariff and the New Brunswick Electricity Market Rules.

The NBSO is the Balancing Authority for New Brunswick, Prince Edward Island, and Northern Maine, and the Transmission Provider for New Brunswick. NBSO provides load following and regulation service to the system in order to supply customer load in the province while maintaining scheduled flows on interconnections within established limits. NBSO is the authority responsible for the operation of the Bulk Power System in New Brunswick, Nova Scotia, Prince Edward Island, and a portion of northeastern Maine.

(4) Québec

Similar to Ontario, the Québec government develops the regulatory framework for wholesale and retail competition. Since 1991 Hydro-Québec has procured some of its power requirements from private producers. The province continues to introduce various programs to stimulate renewable power from hydroelectric and wind powered facilities as well as cogeneration plants fuelled by biomass and natural gas.

In April 2002, the Québec government adopted the *Dam Safety Act (Quebec)* and corresponding regulations. The *Dam Safety Act (Quebec)* imposes a series of safety measures governing the construction, alteration and operation of high-capacity dams. It requires dam owners to maintain their facilities in good repair and monitor their hydraulic works. As a result of this legislation, APCo's Renewable Energy division was required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased by APCo within the Province of Québec.

As a result of the assessments and preliminary evaluation of the associated remedial work, APCo currently estimates it will incur capital expenditures of approximately $17.1 million related to compliance with the legislation. APCo anticipates that these expenditures will be required to be invested over the next five years as follows:

	Total	2011	2012	2013	2014	2015
Estimated Capital Expenditures	**$17,100**	800	5,000	5,500	3,000	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre and Mont-Laurier Facilities. APCo does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. APCo is also exploring several alternatives to mitigate the capital costs of modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

(iii) Material Facilities

(1) Long Sault Rapids Facility

The Long Sault Rapids Facility is an 18,000 kilowatt hydroelectric generating facility located on the Abitibi River, 19 kilometres north of the Town of Cochrane, in northern Ontario. The Facility was commissioned on April 1, 1998.

The facility was developed by a joint venture between Algonquin Power (Long Sault) Partnership and N-R Power Partnership. The Facility is owned by the co-owning joint venturers (the "**Co-Owners**") as tenants-in-common and not as joint tenants, with the co-owners each having an undivided 50% interest in the facility. The partners in the Algonquin Power (Long Sault) Partnership, Algonquin Power (Long Sault) Corporation Inc. and Energy Acquisition (Long Sault) Ltd., are wholly-owned subsidiaries of Algonquin Power Corporation Inc. ("**APC**"), a corporation affiliated with APMI. The partners in the N-R Power Partnership are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There are two non-recourse loans outstanding which are secured against the facility and the Co-Owners' interest therein (see "*Hydroelectric – Long Sault Rapids Facility - Credit Agreements*" below).

APCo's interest in the Long Sault hydroelectric generating facility was acquired by way of subscribing to two notes from the original developers. The notes receivable have a face value of approximately $17 million and bear interest at 9%. APCo earns interest income on the notes and is entitled to 100% of any incremental after tax cash flows from the facility up to 2013, 65% of any incremental after tax cash flows from 2014 to 2027 and 58% of any incremental after tax cash flows thereafter. APCo also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

The facility is a "**run of the river**" facility, which means there is a continuous discharge of water from the facility with no storage and release of water. The powerhouse is an integrated structure, housing four 4,500 kilowatt pit turbine generating units.

i) Power Purchase Agreement

Pursuant to the terms of the PPA, the Co-Owners sell power produced by the facility exclusively to OEFC. The PPA terminates 50 years from the commercial in-service date, April 1, 1998, and may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. The rates are escalated annually based on an index figure tied to the greater of OEFC's Total Market Cost index (a minimum of 1% to a maximum of 8%).

The Co-Owners receive a monthly capacity payment when the facility delivers an average of at least 1,800 kilowatts of power delivered to the delivery point in each fifteen minute interval to OEFC during at least 85% or more of the On-peak period fifteen minute intervals for that month. The "**On-peak**" period is between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays, and "**Off-peak**" is the other remaining hours. Monthly energy in excess of 115% of target generation is subject to an additional payment.

ii) Waterpower Lease

The waterpower lease with the Province of Ontario in respect of the dam site expires in 2048. The lease provides for an annual land rental and an annual water rental charge. The annual water rental charge commenced in January 2008.

iii) Co-Owners Agreement and Management Agreement

The Co-Owners have entered into an agreement concerning, among other things, their holding of undivided interests in the facility. Upon the occurrence of specified events of default, the non-defaulting Co-Owner may purchase the defaulting Co-Owner's interest for 90% of the fair market value. The Co-Owners have entered into a management agreement with NR-Algonquin Energy Management Inc. to manage the facility on their behalf for nominal consideration.

iv) Credit Agreements

There is an outstanding senior loan against the facility in the amount of $39.9 million at December 31, 2010. The loan was provided by a syndicate comprised of The Clarica Life Insurance Company ("**Clarica**"), The Canada Life Assurance Company and The Maritime Life Assurance Company. Clarica acts as agent for the syndicate. The loan has a term of 30 years, maturing in December 2028 and bears interest at an interest rate of 10.16% for the first 15 years and 10.21% thereafter, compounded annually. Blended payments of principal and interest are made monthly. The loan is non-recourse to APCo and is secured by the facility and the ownership interests therein.

Under the terms of the credit agreement, a debt reserve is required. In 2008, APCo issued an irrevocable letter of credit in an amount of $1.2 million to replace the debt service escrow deposit. At December 31, 2010, the debt reserve was fully funded using the irrevocable letter of credit.

In addition, APCo owns the LSR Subordinate Note.

(2) Côte Ste-Catherine Facility

The Côte Ste-Catherine Facility is a hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The Facility has a total installed capacity of 11,120 kilowatts. The Côte Ste-Catherine Facility is owned by the Mont-Laurier Partnership.

i) Land and Water Rights

The land and water rights necessary for the construction and operation of the Côte Ste-Catherine Facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement with the Province of Québec dated March 1, 1988, as amended. In 2009, the existing water rights lease was renewed for an additional term of 21 years commencing March 1, 2009. Although the Facility is located on a federal waterway, the asserted jurisdiction over the water rights to this Facility and has also asserted a claim against a predecessor by amalgamation to APFC for payment of revenues paid to the federal authority. See "*Legal Proceedings*".

(3) Mont Laurier Facility

The Mont Laurier Facility is a 2,725 kilowatt hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The Mont Laurier Facility is owned by the Mont-Laurier Partnership.

i) Land and Water Rights

The facility is constructed on lands owned by the Mont-Laurier Partnership. Water rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources (Québec) pursuant to a lease agreement dated March 23, 1988 and assigned to the Mont Laurier Partnership on October 31, 1994. The term of the lease expires on December 31, 2023.

(4) Côte Ste-Catherine and Mont Laurier, Power Purchase Agreements - General

Each of the Côte Ste-Catherine and Mont Laurier Facilities have PPAs with Hydro-Québec under which all power generated by the facilities is sold to Hydro-Québec. The standard Hydro-Québec PPA stipulates annual minimum energy production requirements in each contract year. Under most Hydro-Québec PPAs, if a facility produces less energy than the minimum, a penalty is payable to Hydro-Québec. The facility can opt to reduce any energy production shortfall over a two year period using energy produced in excess of the minimum requirement, after which, a penalty is payable on any outstanding amounts at the current year prices.

Power purchase rates under the Hydro-Québec agreements (other than for the Mont Laurier and Côte Ste-Catherine (Phase I) Facilities) increase in accordance with the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. The Mont Laurier Facility is subject to a fixed annual escalation of 1.8%. The Côte Ste-Catherine Facility (Phase I) power purchase rate increases at a fixed annual index of 1.1% for the first four years and 1.8% thereafter.

(5) Tinker Hydro Facility

The Tinker Facility is located 5 miles north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The Facility consists of five hydro units and one diesel generator; the total nameplate capacity of the station equals 34.5 MW. Unit 5 of the Tinker Facility is currently operating as a fixed bladed runner. Historical gross generation from the station averages 128,000 MW-hrs per year. The Tinker Facility benefits from the flow regulation of the Millinocket and the Squa Pan Facilities, both of which are also owned and operated by APCo.

i) Transmission facilities

As part of the generation assets in New Brunswick and Northern Maine, APCo owns and operates an electrical transmission system consisting of 14.7 km of 69 kV transmission line facilities. These facilities are used to interconnect the Tinker Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/import capacity between Maine and New Brunswick. The transmission facilities are currently included in the Open Access Transmission Tariff of the NBSO.

ii) Power Purchase Agreements

The Tinker Facility supplies approximately 31,500 MW-hrs per year to the municipal utility of Perth-Andover under a power purchase and sale agreement. The remaining generation from the plant, approximately 100,000 MW-hrs per year, is sold to AES, which provides energy to commercial and industrial customers in the northern Maine and New Brunswick markets, as well as energy and capacity to the Maine and New Brunswick electricity markets.

(6) Dickson Dam Facility

The Dickson Dam Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Dickson Dam Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the waterflows of the Red Deer River. The facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

i) Power Purchase Agreement

The Dickson Dam PPA was entered into with TransAlta Utilities Corporation ("**TransAlta**") on December 7, 1990 and was approved by the Alberta Public Utilities Board on January 16, 1991. It has a term of 20 years ending on January 16, 2012. Under this agreement, TransAlta is obligated to accept delivery of all electricity in amounts up to 115% of the 12.7 MW capacity which is allocated to the Facility at rates stipulated by the Small Power Act.

ii) Use of Works Agreement

The Dickson Dam Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available waterflows for generating power until March 31, 2030. The Use of Works Agreement provides certain rights in favour of the Minister of Environment (Alberta) in connection with the Minister's water management objectives.

(b) Power Generation: Renewable - Wind Power

(i) Production Method

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.

(ii) Principal Markets and Distribution Methods

The principal market for APCo's St. Leon Facility is Manitoba. The electricity generated by the wind turbines at the St. Leon Facility is transmitted via underground distribution lines to the facility's substation for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**"). The purchaser then distributes the electricity to its customers or to other endpoints via the grid.

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

The Manitoba government and Manitoba Hydro have independently undertaken studies to determine the potential of wind power generation in Manitoba. As a result of such studies, the Manitoba Government has advised it plans to have additional capacity of approximately 1,000 MW of wind power, to be constructed, using in part, independent power producers by 2014.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through Crown Investments Corporation. SaskPower anticipates requiring 1,700 MW of additional supply by 2020 and 3,700 MW by 2030 to accommodate load growth and the retirement of generation facilities.

(iii) Material Facilities

(1) St. Leon Facility

The St. Leon Facility is a 104 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The facility is owned by St. Leon LP.

On September 18, 2007, the St. Leon Facility achieved commercial operation pursuant to a turn-key construction contract dated November 12, 2004. In January 2010, APCo executed an Operation and Maintenance Service Agreement with Vestas-Canadian Wind Technology, Inc. ("**Vestas**") whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon Facility for approximately 20 years.

i) Power Purchase Agreement

St. Leon LP and St. Leon GP have entered into a PPA with Manitoba Hydro dated as of October 28, 2004 under which all electricity produced at the St. Leon Facility is sold to Manitoba Hydro. As of June 17, 2006, the facility achieved commercial operation status under the PPA with Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional 5 years. Under the terms of the PPA, security in an amount of $1.8 million is required and as at December 31, 2010, the security was fully funded using an irrevocable letter of credit.

St. Leon LP entered into a Wind Power Production Incentive ("**WPPI**") agreement with the Ministry of Natural Resources - Canada which entitles the St. Leon Facility to receive an incentive from the Federal Government of $10.00 per MW-hr to a maximum of $3.7 million annually for a period of ten years ending March 2016. APCo anticipates that the facility will earn WPPI of approximately $3.0 million annually based on the current estimated long term wind resource.

ii) Credit Facility

A banking syndicate provided a senior loan to the St. Leon Trust to finance construction of the St. Leon Facility. The loan has an amount of $68.7 million outstanding as at December 31, 2010 and matures in October 2011. The senior loan bears interest at banker's acceptance rate plus a banking charge of 1%, payable monthly. St. Leon Trust has entered into a fixed for floating interest rate swap arrangement until September 2015 to fix the interest on the loan at 4.47%. The loan is secured solely by the facility and the ownership interests therein.

(2) Red Lily I

Red Lily I is a 26.4 MW wind generation facility located 5 kilometres west of Moosomin, Saskatchewan. Red Lily I consists of 16 Vestas V82 wind turbine generators. The equity in Red Lily I is owned by an independent investor, Concord Pacific Group. APUC has a senior debt investment in the facility which will be $13 million by the end of April 2011 and bears interest at the rate of 6.99%. Additional senior debt of $31 million has been provided by a third party lender, Integrated Private Debt. APCo has a subordinated debt investment in the facility of $6.6 million and bears interest at the rate of 12.5%. APCo has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest, exercisable in February 2016.

In addition to interest payments on its debt financing, APUC is entitled to certain supervisory fees, estimated at $1.3 million in the first full year of operation. Total interest and fee payments in 2011 are estimated to be approximately $2.4 million representing approximately 75% of net cash flows from the facility.

i) Power Purchase Agreement

Red Lily I entered into a 25 year PPA with SaskPower dated as of July 30, 2008, which includes a 2% annual increase throughout the term of the agreement. On February 25, 2011, Red Lily I commenced commercial operation under the SaskPower PPA.

(c) Power Generation: Thermal - Energy From Waste

(i) Production Method

In North America and elsewhere, the combination of increasing population and stricter environmental regulations has imposed increasing limitations upon the development of new municipal landfills and on the expansion of existing landfills. To reduce the total tonnage of municipal waste being directed to landfills and to extend the useful life of existing landfills, considerable effort is being directed toward the establishment of energy-from-waste facilities. The establishment of energy-from-waste facilities is now a licensed process in certain states of the United States and Canadian provinces.

The heat recovered from municipal solid waste is used to make steam which can be used to provide thermal energy or can be used to drive turbines and generate electricity.

(1) Principal Markets and Distribution Methods

See "*Material Facilities*".

(ii) Material Facilities

(1) EFW Facility

The EFW Facility is a 10 MW generating station located in Brampton, Ontario which produces electricity from incinerating non-recyclable materials, including municipal solid waste. The facility is designed to incinerate over 500 tonnes per day of municipal solid waste from five incinerators to produce an average of approximately 60,000 pounds per hour of steam which is the excess of the steam required for production of internally consumed electricity. It is owned by APEFW which forms part of the APCo ownership chain.

The majority of the EFW steam is diverted to the BCI Facility. See "*BCI Facility*" under "*Material Facilities*" for "*Cogeneration*". A portion of the EFW Facility steam is used by the EFW Facility to generate electricity in a steam turbine generator, the electricity from which is used to supply internal operations with any excess generation being sold to OEFC.

i) Power Purchase Agreement

The EFW Facility has entered into a PPA with OEFC which requires OEFC to purchase all the electricity produced by the facility. The OEFC uses the electricity to supply the grid in Ontario. The PPA expires in 2012. The Ontario Ministry of Energy has directed the OPA to enter into negotiations with APEFW to negotiate a new a new long term contract for the power output from the EFW Facility.

ii) Fuel Supply

Under a "tip or pay" waste supply agreement, Peel supplies the facility with a minimum of 127,900 tonnes per year of acceptable municipal solid waste. The agreement expires in 2012. Peel has the option to renew the agreement for an additional five-year term. The agreement requires Peel to pay a "tipping fee" for each tonne of acceptable waste delivered, plus an additional fee for each tonne of acceptable waste delivered above the base amount. Additional volumes of waste may be supplied by Peel at the request of either party, subject to the agreement of the other. The agreement provides that if certain taxes are imposed or revised standards are set for certain environmental or operating matters affecting the facility, the tipping fees paid by Peel will be increased to reflect the increased capital or operating costs so imposed by the taxes or revised standards.

(d) Power Generation: Thermal - Cogeneration

(i) Production Method

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. Often natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

Where both electrical and thermal energy are generated separately, typically one third to one half of the fuel's energy content is converted into useful energy output such as steam or electricity. The remainder is wasted energy which escapes as unused heat. By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel's energy content. Depending on the degree of steam and/or useful heat utilization, 55% to 80% of the fuel's energy content is converted into useful energy output, which produces significant fuel savings over conventional arrangements.

Cogeneration compared to conventional processes also has environmental benefits as it results in burning less fuel and producing less carbon dioxide. Furthermore, in cogeneration facilities which use fuels such as natural gas or oil, sulphur dioxide and nitrous oxide emissions are greatly reduced compared to other technologies and fuels.

(ii) Principal Markets and Distribution Methods

The principal markets of APCo's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to Independent System Operator rules. In addition, electrical capacity and other ancillary services are sold either under the terms of a long term contract or according to the Independent System Operator rules. A summary of the contracts for the Cogeneration Facilities is attached in Schedule B. In addition to grid sales of electricity and power, electricity and thermal energy is also sold to nearby third party purchasers for use in their production facilities.

(1) California

The electric transmission system and wholesale markets in California are primarily regulated by the California Energy Commission and FERC. The California Independent System Operator administers the wholesale electricity market place for the region.

(2) Connecticut

Connecticut Light and Power Company ("**CL&P**") is part of the North East Utilities System which is located in the New England Power Pool. ISO-NE was established as a not-for-profit, private corporation on July 1, 1997 following its approval by FERC. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

Since May 1, 1999, ISO-NE has also administered the wholesale electricity marketplace for the region. Six electricity products are bought and sold by market participants on an internet-based market system.

(iii) Material Facilities

(1) Sanger Facility

The Sanger Facility is a 56MW natural gas-fired generating facility located in Sanger, California. The Sanger Facility is a combined cycle generating station comprised of a 44 MW General Electric LM6000 natural gas fired turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, commissioned in 1991. The facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

i) Power Purchase Agreement

Output of the Facility is governed by the terms and conditions of a firm capacity and energy PPA with Pacific Gas & Electric Company ("**PG&E**"). The agreement has a term of 30 years, expiring in 2022, and calls for delivery of 38 MW of firm capacity.

ii) Fuel Supply

Natural gas for the Facility is delivered under the terms of a gas supply agreement dated August 1, 2006 with Constellation NewEnergy for the purchase and sale of all natural gas required for the facility. The expected gas requirement for the subsequent month is bought at the market rates available on the gas nomination date, which is typically the 20th day of each month. Gas above or below the nomination requirement can be bought or sold at the applicable spot prices.

iii) Energy Lease

Pursuant to a lease, energy supply and common services agreement with Dyna Fibers Inc., a wholly-owned subsidiary of Sanger LLC, Dyna Fibers Inc. leases a portion of the facility site in order to carry on its hydro mulch business and purchases certain energy at a cost equal to a percentage of the fuel costs incurred by the Facility, to offset the incremental cost of fuel to supply such energy. The water consumption, exhaust heat and steam consumption by the hydro mulch operations are metered and recorded for FERC qualifying facility calculations that are submitted to PG&E on an annual basis.

iv) Credit Facility

There is an outstanding senior loan against the Facility in the amount of US $19.2 million as at December 31, 2010. The loan is a California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond, due September 1, 2020. The senior loan bears interest at variable rates, reset monthly. Interest is payable monthly with no principal repayments. The effective interest rate in 2010 was 1.33%. The loan is secured solely by the Facility, the ownership interests therein and an irrevocable letter of credit in an amount of US $19.5 million.

(2) Windsor Locks Facility

The Windsor Locks Facility is a 56 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks Facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine and was commissioned in 1990. The Facility is owned by Algonquin Power Windsor Locks LLC, an indirect subsidiary of APCo.

Prior to April 2010, the Windsor Locks Facility ran at capacity, providing the steam and power requirements of Ahlstrom pursuant to the Energy Services Agreement ("**ESA**") with the remainder of the electrical generation being sold to CL&P. With the expiry of the PPA with CL&P, APCo determined that the existing gas turbine is not appropriately sized to meet the electrical and steam requirements of Ahlstrom.

In this regard, APCo has completed preliminary engineering and environmental permitting work for the installation of a more appropriately sized 14.2 MW combustion gas turbine. The total expected capital cost for this project is estimated at approximately U.S. $20 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to US $450/KW to a maximum of U.S. $6.6 million to offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to Windsor Locks of approximately U.S. $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate and maintain the existing equipment. APCo also believes that this project would qualify for a combined heat and power Investment Tax Credit ("**ITC**") Grant program sponsored by the US Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut grant. APCo's decision to make any investment in new capital for this site will be based on an assessment of the incremental earnings and certainty of such incremental earnings against such additional investment. With a repowered facility the existing combustion turbine would continue to be used as a capacity and reserve resources participating in the ISO-NE markets.

i) Energy Services Agreement and Ground Lease

The Windsor Locks Facility supplies thermal steam energy and a portion of electrical generation to Ahlstrom, a leading paper and non woven materials manufacturer, pursuant to a ground lease and the ESA. Pursuant to the ESA, Ahlstrom leases to the facility site to Algonquin Power Windsor Locks, LLC and utilizes thermal steam energy and a portion of electrical generation of the Windsor Locks Facility for use at its specialty fibers composites mill located adjacent to the Windsor Locks Facility. Both the ground lease and the ESA expire in January 2018, subject to certain early termination rights in favour of Ahlstrom and rights of renewal in favour of both parties. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Facility.

ii) Power Purchase Agreement

The electrical output of the Windsor Locks Facility not used to meet Ahlstrom's requirements is committed to the ISO-NE electricity market. Since April 2010, the Windsor Locks Facility has bid its remaining available capacity of approximately 40 MW into the thirty minute forward operating reserve market. APCo has entered into an agreement with Emera Energy Services Inc. to manage the off-take sales from this Facility into the ISO-NE market. See "*Current Development Projects - Windsor Locks*" under "*Development*" for further details.

iii) Fuel Supply

Natural gas for the facility continues to be delivered under a gas supply agreement with Yankee Gas Service Company ("**Yankee Gas**"). Gas is supplied by Yankee Gas at a percentage of its weighted average cost of gas for the month. The gas contract contains minimum annual consumption requirements with associated penalties for shortfalls. The Yankee Gas agreement was scheduled to terminate coincident with the PPA. APCo and Yankee Gas continue to negotiate a new agreement that will allow Windsor Locks to use Yankee Gas as a local distribution company which will enhance the Windsor Locks Facility's purchase options for its natural gas requirements.

(3) BCI Facility

The BCI Facility is a cogeneration facility located in Brampton, Ontario on the EFW Facility site. It was commissioned and became operational in June 2008. The project was established to meet the steam requirements of a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities.

The facility consists of a 150,000 pound per hour gas-fired boiler, a water treatment system, pumps to support the boiler, a twelve inch diameter pipeline to supply a nearby recycled paper board manufacturing mill with steam and a six inch diameter pipeline for condensate return. The majority of the steam supplied to the mill is produced by the EFW Facility with the gas-fired auxiliary boiler supporting peak steam demand and providing full standby capacity during normal downtime periods at the EFW Facility and where operations at the EFW Facility cannot provide sufficient volume of steam.

(4) Kirkland Facility

The Kirkland Facility is a 132MW combined cycle integrated fuels generation station located in Kirkland Lake, Ontario owned by Kirkland Lake Power Corp. ("**Kirkland**") which burns natural gas and wood waste to generate electricity using four gas turbines and two steam turbines. The Kirkland Facility was developed in two phases: the first 102MW was commissioned in 1991, operating in baseload, and the remaining 30MW was added in 2004 as a dispatchable or peaking plant. Northland Power Inc. ("**Northland**") manages the operations. Electricity produced by the Facility is sold to OEFC pursuant to a 40 year contract, which expires in 2030. Natural gas used by the Kirkland Facility is supplied under 20 year supply contracts. Price increases under such gas supply agreements are generally tied to price increases under the PPAs with OEFC. Wood waste consumed by the Kirkland Facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 32.4% of the Class B non-voting shares issued by Kirkland. It is Kirkland's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Kirkland had a put option to sell the Kirkland Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $10 million. Further to a shareholder meeting on November 12, 2009, the Kirkland shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the Facility is paid to Northland under the management agreement.

(5) Cochrane Facility

The Cochrane Facility is a 40MW combined cycle integrated fuels generating station located in the Town of Cochrane, Ontario. The Cochrane Facility is owned by Cochrane Power Corporation ("**Cochrane**") which burns natural gas and wood waste to generate power using a gas turbine and a steam turbine. The Cochrane Facility was commissioned in 1990 and is currently managed by Northland. Electricity produced by the Cochrane Facility is sold to OEFC pursuant to a 25 year contract, which expires in 2014. The majority of the natural gas used by the Facility is supplied under a supply contract which expires in 2016. Price increases under such gas supply agreements are generally tied to price increases under the PPA with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 25% of the Class B non-voting shares issued by Cochrane. It is Cochrane's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Cochrane had a put option to sell the Cochrane Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $3 million. Further to a shareholder meeting on November 12, 2009, the Cochrane shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the facility is paid to Northland under the management agreement.

(e) Power Generation: Energy Services Business

The primary business of the Energy Services Business is to market the output of the Tinker Facility which would otherwise sell the energy it generates on a merchant basis. The Energy Services Business also works to develop strategies for selling the power output of other APCo facilities that are approaching the end of their PPAs and to engage, where possible, in actual selling of power for APCo facilities that would otherwise sell power on a merchant basis.

(i) Production Method

The Energy Services Business involves standard offer contracts and direct customer contracts for the supply of energy to commercial and industrial customers. The Energy Services Business is based on a series of short-term energy supply agreements.

(ii) Principal Markets and Distribution Methods

The Energy Services Business provides energy to commercial and industrial customers in the northern Maine and New Brunswick markets. The Energy Services Business anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 100,000 MW-hrs of energy to its customers at an average rate of $86/MW-hr on an annualized basis.

The Energy Services Business purchases the majority of its energy requirements from the Tinker Facility. Based on historical long term average levels of hydroelectric energy generation, the Tinker Facility is anticipated to provide greater than 65% of the energy required by the Energy Services Business to service its customers and provides a natural hedge on supply costs of the Energy Services Business.

In addition to the energy generation provided by the Tinker Assets, the Energy Services Business purchases additional energy on the open market in order to services its customer demand. APCo manages the risk associated with this business through internally generated energy from the Tinker Assets, as well as through the purchase of fixed volume/prices from the ISO-NE market. In addition, APCO negotiates appropriate consumption volumes and pricing indexes with large retail and wholesale consumers in northern Maine to ensure risk associated with volatility of consumption by the consumer is mitigated.

(iii) Material Facilities

The Energy Services Business is based on a series of energy supply agreements. These include energy sales to a town in New Brunswick, Standard Offer Service contracts with two local electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine.

The hydroelectric and thermal generation assets offer capacity to support the energy services obligations in northern Maine. The acquisition improves hydrologic diversification through a new geographical area to the APCo generation portfolio and builds APCo’s Eastern Canadian generating presence.

The Energy Services Business involves Standard Offer contracts for the supply of energy to commercial and industrial customers in northern Maine, as well as energy purchase obligations with the ISO-NE required to supplement self-generated energy. Subsequent to December 31, 2010, the Energy Services Business entered into a three year contract with MPS starting March 1, 2011 to provide Standard Offer Service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with the standard offer service is approximately 135,000 MW-hrs.

(f) Power Generation: Development

(i) Target Markets / Development Strategy

The Development division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. The Development division is led by six full time employees who have access to, and support from, all of APCo's available resources to assist it in the development of projects. Typically, the division draws upon the support of the finance, engineering, technical services, and environmental and regulatory compliance groups. It also utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The Development division believes that the prevailing economic climate has also created opportunities for APCo to acquire third party development projects on terms that require the experience and financial resources that APCo has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

(ii) Principal Market Environment

APCo believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the U.S., continue to increase targets for renewable and other clean power generation projects. In May 2009, the Ontario government passed the GEA. Accordingly the OPA has issued standard pricing for electricity from renewable sources under a FIT program. Included within this legislation is the requirement for OPA to purchase power generated from green energy projects, and an obligation for all utilities to grant priority grid access to such projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.

Other jurisdictions have passed similar legislation. British Columbia has announced the Clean Energy Act and Nova Scotia is pursuing the 2010 Renewable Electricity Plan and will be establishing pricing for its ensuing Community FIT program in April of 2011. Both of these proposed pieces of legislation have set aggressive targets for the development of new, renewable power production. They also introduce the concept of fixed pricing based on a FIT for some categories of new renewable power projects. The combination of increased renewable production targets and appropriate fixed pricing will present investment opportunities for APCo to consider in the future.

APCo continues to actively pursue development projects which provide the opportunity to exhibit accretive growth. APCo anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being extensively supported by Canadian provincial governments and a significant number of U.S. states.

In the United States, the *New Energy for America Plan* supports 10% of the country's electricity being generated from renewable sources by 2012 and 25% by 2025. The demand for additional renewable power is also expected to benefit from the desire by various government entities to increase infrastructure spending.

(iii) Current Development Projects

(1) Amherst Island

On February 25, 2011, APUC announced that the OPA has awarded a FIT contract to Windlectric, owner of the wholly-owned 75 MW Amherst Island Wind Project, located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. The contract has been awarded as part of the second round of the OPA's FIT program.

The project is currently contemplated to use more efficient Class III wind turbine generator technology and will be developed by APCo. While final turbine selection remains to be made, modelling the higher energy capture ratios of turbines, such as the Vestas V100 or Repower MM100, forecast that the available wind resource would produce approximately 247 GW hrs of power annually. Funding for the total capital costs currently estimated to be $220 million will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 months.

(2) Quebec Community Wind Projects

In July 2010, APCo and Société en Commandite Val-Eo, a cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase submitted separate proposals into Hydro-Québec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded contracts that stipulate the use of ENERCON turbines.

(3) Saint-Damase

The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APCo. The first 24 MW phase of the project is currently envisioned to consist of twelve 2 MW ENERCON E-82 wind turbine generators, producing approximately 86,000 MW-hrs annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

The interest of APUC in the project is subject to final negotiations with the municipality but, in any event, will not be less than 50%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011, with all major authorizations targeted for completion by the end of 2012.

(4) Val-Éo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight 3 MW ENERCON E-101 wind turbine generators, producing approximately 66,000 MW-hrs annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interest of APUC in the project is subject to final negotiations with the municipality but, in any event, will not be less 25%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011, with all major authorizations targeted for completion by the end of 2012.

(5) Morse

On March 21, 2011, APCo announced it has executed an asset purchase agreement with Kineticor to acquire the Morse Projects, assets related to two proposed adjacent 10 MW wind energy development projects in Saskatchewan.

The Morse Projects were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program in May 2010. Upon SaskPower's approval and execution of the PPAs, Kineticor will assign the PPAs to APCo. The Morse Projects are expected to be completed in late 2013.

The Morse Projects are to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina and 400 km west of the 26.4 MW wind generation facility in southeastern Saskatchewan. It is contemplated that the Morse Projects will be situated on 1,120 acres of private lands, with additional land under lease or option in order to facilitate future expansion of the Morse Projects.

The total annual energy production for the Morse Projects is estimated to be 75,000 MW-hrs. While equipment selection and construction details remain to be finalized, the capital cost to construct the Morse Projects is currently estimated to be $55-$60 million, inclusive of acquisition costs. The first year PPA rate is set at $101.98 per MW-hr for the first full year of operations, which APCo expects to occur in 2014, with an annual escalation provision of 2% over the expected 20 year term.

(6) Red Lily II

In addition to the now completed Red Lily I project, APCo has secured additional land options related to property around Red Lily I to facilitate a 106 MW expansion ("**Red Lily II**"). The viability of the expanded project will be conditional upon a review of the actual operating results from Red Lily I. During the first quarter of 2010, APCo responded to the request for quotations issued by SaskPower by submitting requested information pertaining to Red Lily II.

Successful development of wind projects is subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs and construction risk that the project is built without mechanical defects and is completed on time and within budget estimates.

(7) Windsor Locks

The Windsor Locks Facility is a 54 MW natural gas power generating station located in Windsor Locks, Connecticut. This Facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to the ESA.

The balance of the Windsor Locks Facility's electrical generating capacity is sold to customers through the ISO-NE electrical market. The facility currently participates in the ISO-NE Forward Capacity Market and the day-ahead energy market. Assuming acceptable auction pricing is available in April 2011, the additional electrical capacity of approximately 26 MW at the Windsor Locks Facility will be made available into the summer 2011 Forward Reserve Market. In addition, APCo's Energy Services Business will use the production from the Windsor Locks Facility to support retail industrial electrical sales in the ISO-NE market.

APCo has completed preliminary engineering and environmental permitting work for the installation of a 14.2 MW combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of Ahlstrom. The total expected capital cost for this project is estimated at approximately U.S. $20 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million to offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Windsor Locks Facility of approximately $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO-NE market. APCo also believes that this project would qualify for a combined heat and power ITC sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant. APCo's decision to make any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

During 2011, it is expected that APCo will continue to earn revenue from steam and electrical sales to Ahlstrom, steam and electrical capacity payments made by Ahlstrom, as well as energy and capacity payments through sales to ISO-NE. Under the expected ISO-NE operating protocol APCo will need to acquire approximately 0.9 million MMBTU of natural gas annually in addition to the amount of natural gas purchased to serve the needs of Ahlstrom (in respect of which APCo receives reimbursement from Ahlstrom under the ESA).

(8) Other

APCo has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. APCo believes this project is an excellent fit for the Minister of Energy and Infrastructure's (the "**Ministry**") Directive to procure electricity from combined heat and power projects. The Ministry is currently taking registrations from interested parties that wish to participate in such a program.

(iv) Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the U.S.

APCo is currently collecting wind data on three sites in Saskatchewan and responded to Saskatchewan's Request for Qualifications to procure up to 175 MW of wind power from one or more independent power producers. These sites have met the qualifications and APCo will likely submit project proposals into future RFPs.

Discussions with the OPA indicate that energy procurement initiatives have been positively influenced by the GEA. The GEA is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by APCo as positive for the development of renewable energy in Ontario. The Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the OPA in accordance with the GEA.

APCo had previously submitted applications for approximately 120 MW of on-shore wind energy projects in eastern Ontario under the GEA's FIT program. The on-shore wind price set by the FIT program is $0.135 per KWh. APCo has received confirmation from the OPA that the remaining 42 MW of applications submitted under the FIT program are now being reviewed under the Economic Connection Test.

APCo has applied to become applicant of record for three Crown land sites in Ontario under the Ministry of Natural Resources wind power site release program.

Each project being contemplated is subject to a significant level of due diligence and financial modeling to ensure it satisfies return and diversification objectives established for the Development division. Accordingly, the likelihood of proceeding with some or all of these projects depends on the outcome of due diligence, material contract negotiations, the structure of future calls for tender, and request for proposal programs. To maximize APCo's opportunities for development, new renewable and high efficiency thermal energy generating facilities are being pursued utilizing a variety of technologies and in diverse geographic locations.

(v) Future Development Projects – Existing Facilities

(1) St. Leon II

APCo is exploring multiple options related to the St. Leon facility including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 85 MW. In the event these projects are developed, it is currently estimated to require an investment of approximately $250 million.

(g) Utilities: Water and Wastewater

(i) Method of Providing Services and Distribution Methods

A utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation.

The raw water for human consumption is sourced from the ground and extracted through wells or from surface waters such as lakes or rivers. The water is treated to potable water standards that are specified in Federal and State regulations and which are typically administered and enforced by a State or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility.

The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fee, reconnects, etc.

In respect of sewer or wastewater services, the sewage or wastewater produced by the customer flows through a buried service lateral line from the house or commercial space to the street which line is owned and maintained by the customer. This line feeds into collection pipes or lines (collection mains) located under or adjacent to the street which pipes are owned and maintained by the private utility. These pipes generally slope at a grade of approximately 1% as gravity is generally relied on to facilitate flows. On long line runs where maintaining slopes would result in excessive depths below grade or to traverse variable terrain, the line may terminate at a lift station where wastewater is collected and then pumped up to feed into another line located closer to the surface level where the wastewater can continue to flow by gravity.

The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks digested and or dewatered and the resulting solids sent to landfill or to land application as a soil amendment. The treated water, referred to as “effluent”, is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface waters. The standards to which this wastewater is treated are specified in each treatment facilities operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on Federal and State regulations which are administered and continuing compliance therewith enforced by the State agency to which Federal enforcement powers are delegated.

(ii) Principal Markets

The principal markets of Liberty Water are located in Arizona, Texas and Missouri. Liberty Water’s facilities are generally subject to regulation by the public utility commissions of the States in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The utilities use a historic test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility’s customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Water monitors the rates of return on each of its utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for the Water Services business unit is attached in Schedule C.

(1) Arizona

The ACC is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The Arizona Department of Environmental Quality ("**ADEQ**") and the Arizona Department of Water Resources in conjunction with various County agencies (county health units) have primary jurisdiction respecting environmental regulation and compliance.

(2) Texas

The Texas Commission on Environmental Quality (the "**TCEQ**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. The TCEQ also has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal *Clean Water Act* and the *Safe Drinking Water Act*, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(iii) Material Facilities

(1) Gold Canyon Facility

The Gold Canyon Facility is a wastewater treatment facility established in 1984 to serve a number of residential developments and in an unincorporated area of Pinal County referred to as Gold Canyon, approximately 25 miles east of downtown Phoenix, Arizona. The Facility currently serves over 7,300 residential and commercial customers. The Gold Canyon Facility is owned by a wholly-owned subsidiary of Liberty Water.

The treatment plant utilizes an extended aeration process combined with a sequencing batch reactor with a treatment capacity of 1.9 million gallons per day ("**gpd**").

The Facility is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on three neighbouring golf courses. Excess reclaimed water is recharged (put back into the ground to replenish underground water) via three recharge ponds. The treatment facility operates under ADEQ – Aquifer Protection Permits and Reuse Permits.

(2) Litchfield Facility

The Litchfield Facility is a water distribution and wastewater treatment facility located in the West Valley of Maricopa County, 15 miles west of Phoenix, Arizona whose service area includes sections of the cities of Goodyear and Avondale. The Litchfield Facility is owned by a wholly-owned subsidiary of Liberty Water.

The Litchfield Facility presently serves approximately 16,500 water and 18,500 wastewater customers. The wastewater facility has permitted capacity of 4.1 million gpd. The Facility's water infrastructure includes a total of twelve active wells, a 6.3 million gallon reservoir and a 4.0 million gallon reservoir which provides water to the current customer base through a single pressure zone. In 2007, in response to high growth in connections, the Facility began preparing design plans for expansion of its wastewater treatment facility. However, while permitting such expansion is currently underway, slowed growth has now postponed such construction plans and expansion of capacity is now anticipated to begin in 2012 or 2013, depending on local demand growth occurring. The Facility now operates at approximately 85% of design capacity. The Facility supplies Class “A+” effluent to a number of local golf courses in the area.

(iv) Credit Facility

The Litchfield Facility currently has outstanding indebtedness to the City of Goodyear in the amount of U.S. $11.0 million in respect of which the City of Goodyear has acted as a conduit issuer of a like amount of Industrial Development Authority bonds. The bonds consist of two series, both fully amortizing over a 30 year term. The first series was issued in 1999, has a principal amount as of December 31, 2009 of U.S. $3.8 million bearing interest at the rate of 5.87%. The second series was issued in 2001 with a principal amount as of December 31, 2010 of U.S. $7.2 million and bearing interest at the rate of 6.71%. As partial security for these bonds, the Facility is required to hold funds in a restricted, interest bearing, investment account. The balance of this account at December 31, 2010 was U.S. $1.1 million.

(1) Rio Rico Facility

The Rio Rico Facility is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona. The Facility serves approximately 6,700 water and 2,200 wastewater connections in the community of Rio Rico, Arizona. The Facility is owned by a wholly-owned subsidiary of Liberty Water.

The Rio Rico Facility has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the ACC.

(2) Rate Cases - General

In 2010, Liberty Water completed the regulatory process with rate cases relating to a number of its facilities. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Water monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

The following table sets out some particulars with respect to the status of Liberty Water’s rate cases as at March 15, 2011:

Completed Rate Cases	Date of Rate Increases	Annual U.S. $ Revenue Increase Requested	Annual U.S. $ Revenue Increase Granted
Facility			
Arizona			
Black Mountain	October 2010	$ 1.0 million	$ 0.7 million
Litchfield	December 2010	$ 11.6 million	$ 7.1 million
Rio Rico	February 2011	$ 1.6 million	$ 0.9 million
Texas			
Texas Utilities (Silverleaf – 4 utilities)	October 2009	$ 1.2 million	$ 1.2 million
Tall Timbers	July 2009	$ 0.2 million	$ 0.2 million

Woodmark	January 2010	$ 0.1 million	$ 0.1 million

Rate Cases Awaiting Recommended Order & Opinion	Estimated Annual U.S. $ Revenue Increase Requested
Facility	
Arizona	
Bella Vista, Northern and Southern Sunrise	$ 1.1 million

In Arizona, the ACC requires a full regulatory process for all rate cases using a historic test year. On August 5, 2010, the Black Mountain Facility received a recommended order ("**ROO**") recommending an annualized rate increase of approximately U.S. $0.7 million effective September 1, 2010. The Black Mountain Facility filed its rate case in December 2008 using a June 30, 2008 test year. The ROO was approved in entirety at the Commission's open meeting held in August.

On October 5, 2010, Liberty Water received a ROO for the Litchfield Facility proposing an annualized revenue increase of U.S. $8.1 million. At the ACC open meeting held on December 10, 2010 to consider the ROO, the approved revenue increase was reduced to U.S. $7.1 million, with new rates effective December 1, 2010. As part of the Litchfield ROO, the rate increase will be phased in with 50% of the increase being applied in the first 6 months, increasing to 75% for 6 months thereafter, and 100% of the rate increase being realized from month 12 forward. Litchfield is entitled to recover the foregone revenue from the phase in of rates including carrying charges under terms to be determined during the second phase of the Litchfield rate case which will focus on amounts charged for hookup fees and the methodology for recovery of foregone revenues due to the phase in of the rate increase. This phase is expected to occur later in 2011. The Litchfield Facility filed its rate case in March 2009 using a September 2008 test year.

On December 11, 2011, the ACC approved an order authorizing an annualized rate increase of U.S. $0.9 million for the Rio Rico Facility, effective February 1, 2011. The Rio Rico Facility filed its rate case in May 2009, using a test year ended December 31, 2008.

The Bella Vista, Northern Sunrise and Southern Sunrise Facilities filed rate cases in August 2009 using a March 31, 2009 test year. It is anticipated that the regulatory review of the proposed rates and tariffs for Bella Vista, Northern Sunrise, and Southern Sunrise Facilities will be completed in Q1 2011.

All of these facilities are located in Arizona.

In Texas, the TCEQ allows the utility's customers a period of 90 days from the effective date of the proposed rates to object to the imposition of interim rates pending final rates determination. If greater than 10% of a specific Texas utility's customers object to the new proposed rates, the proposed rates would be subjected to a full regulatory hearing process administered by the TCEQ in order to finalize the rates. If fewer than 10% of the customers record an objection to the proposed rates, those proposed rates are likely to be adopted and declared final as proposed. Any difference between the interim rates charged and collected and the final rates as approved by TCEQ will be subject to a retroactive adjustment and refund on the customers' subsequent monthly bill.

Liberty Water entered into negotiated settlements with the customers of the Texas Silverleaf and Tall Timbers Facilities, resulting in the achievement of the full estimated annualized revenue increase of $1.2 million and $0.2 million, respectively. The Woodmark Facility did not receive objections from 10% of the customer base and also achieved the full estimated annualized revenue increase of $0.1 million. The five

Texas Facilities filed rate cases in April 2009, and Woodmark in Texas filed in July 2009, all with test years ended December 31, 2008.

(h) Utilities: Electrical Distribution

(i) Method of Providing Services and Distribution Methods

Electricity distribution is the final stage in the delivery of electricity to end users. A distribution system's network carries electricity from the transmission system and delivers it to consumers or other end users. Typically, the network would include medium-voltage (less than 50 kV) power lines, electrical substations and pole-mounted transformers, low-voltage (less than 1 kV) distribution wiring and sometimes electricity meters.

An electric distribution utility sources and distributes electricity it to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities which can use various fuels such as water (hydro), natural gas, coal, biomass, wind, nuclear and solar. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customer where the voltage is again lowered through a transformer for use by the customer.

The fees or rates charged for electricity are comprised of a fixed charge component plus a variable fee based on the cost for generation, transmission and distribution of the electricity. Additional fees are typically chargeable for other services such as establishing a connection, late fee, reconnections, etc.

Liberty Energy's facility is subject to state regulation and rates charged by these facilities may be reviewed and altered by the State regulatory authorities from time to time.

(ii) Principal Markets

The principal market of Liberty Energy is currently in the State of California. The utility operates under a cost-of-service regulation. The utility uses a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on facilities, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which the utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Energy monitors the rates of return on its utility investment to determine the appropriate time to file a rate case in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for Liberty Energy's California Utility is attached in Schedule D.

(1) California

The CPUC regulates electrical utilities in California. The CPUC has jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These regulatory bodies have the authority to establish the allowed rate of return on approved rate base and also determine which investments are approved for inclusion in the rate base which in both cases can affect the profitability of the division.

The California regulatory regime requires regular general rate case filings. This obligates any regulated utility operating in California to file a rate case every 3 years and allows for the use of a prospective test year in the establishment of rates for the utility. The CPUC also allows the use of annual adjuster mechanisms to account for inflation to labour and other expenses over the three year period of the rate case filing. In addition, a utility's rates include thresholds for capital expenditures, which once reached, can trigger adjustment mechanisms in between rate cases.

The Energy Cost Adjustment Clause ("**ECAC**") allowed in California mitigates the impact of changes in fuel prices and stabilizes earnings by allowing for the recovery of fuel and purchased power costs by updating rates charged on an annual basis. The Post Test Year Adjustment Mechanism ("**PTAM"**) allows Calpeco to update its rates annually by a cost inflation index. In addition, rates are allowed to be updated to recover the return on investment and associated depreciation of major capital projects.

(iii) Material Facility

(1) California Utility

The California Utility provides electric service to the Lake Tahoe basin and surrounding areas. The service territory, centered around a popular tourist destination, has a primarily residential and small commercial customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in Northeastern California. The utility plant is comprised of approximately 94 miles of high voltage distribution lines, 13 substations, and 39 distribution circuits (14.4 kV) serving just over 48,000 customers in the seven County service territories. The customer base is heavily-weighted towards El Dorado and Placer Counties, which counties comprise approximately 89% of total revenues.

Calpeco is owned by CPUV, a 50.001% subsidiary of Liberty Energy.

Calpeco's most recent rate case was settled in 2009. It is anticipated that the next Calpeco rate case will be filed in June 2011 for the prospective years of 2012-2014.

i) Customer Base

Calpeco's customer base is primarily residential with exposure to large commercial accounts limited to under 20% of gross revenues. The existing commercial customers primarily consist of ski resorts, hotels, hospitals, schools and grocery stores with no single customer accounting for more than 3.6% of annual sales volume.

ii) Kings Beach Generation

Calpeco has a local-area emergency backup generation facility at Kings Beach in Placer County, California. The facility consists of six new Caterpillar 3516 Engine diesel generation units with a total nameplate capacity of 12 MW. The units were installed in November 2008 at a cost of U.S. $16.5 million and have an estimated useful life of 30 years. The repowered facility meets all California environmental standards including the new California Particulate Matter emission requirements and NOx emissions limits. Any non-preventative maintenance expenditures that may occur during the first five years of operation will be fully covered by the Kings Beach warranty.

In the event of a system outage, the Kings Beach Facility is able to provide back-up generation support to Calpeco's service territory until baseload power is restored. The facility includes quick-start technology which facilitates this support function. The new units are designed to be online and operating within 60 seconds of being activated. The facility has historically run an average of 200 hours per year.

iii) Energy Cost Adjustment Clause

ECAC is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. The mechanism consists of a base rate and amortization rate set at the time of the general rate case. The actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

iv) Post Test Year Adjustment Mechanism

In years where Calpeco does not file a general rate case, its rates are updated on January 1st to reflect inflationary increases to its administrative, operations, and maintenance costs. The inflationary adjustment is set by the use of an index, less a presumed efficiency offset.

Calpeco may also file for an annual increase in rates to recover its investment costs in material capital projects. This increase is subject to a materiality threshold.

v) Power Purchase Agreement

Calpeco has entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at rates NV Energy's "system average cost". The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply Calpeco with sufficient renewable power to satisfy the current 20% California Renewables Portfolio Standard requirement for the five-year term of the PPA.

NV Energy's deliveries under the PPA are structured in a manner which satisfies the CPUC resource adequacy ("RA") requirements, and designed to enable Calpeco to comply with the associated RA reporting requirements.

vi) Credit Facility

Calpeco entered into a long term debt private placement in an amount of U.S. $70.0 million on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate, interest only, and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

3.3 Revenues for 2010 and 2009

As at March 31, 2011, APUC owned, directly or indirectly, debt, equity and royalty and other interests in 59 power generation facilities including those identified in "Other Interests in Energy Related Developments", one electrical distribution facility and 19 water distribution and wastewater facilities. For the year ended December 31, 2010, APUC derived approximately 74.4% of its revenues from its interests in power generation facilities (71.7% in 2009), 4.9% of its revenues from waste disposal fees (7.7% in 2009) and 20.7% of its revenues from its interests in water distribution and wastewater facilities (20.6% in 2009).

3.4 Specialized Skill and Knowledge

The senior executives of APUC have extensive contacts in the independent power industry in Canada and the United States. APCo, as well, has extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of APCo requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to APCo in-house.

The energy from wind aspect of the business of APCo requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to APCo in-house. On a more general level, the production of energy from all facilities of APCo requires specialized skill and knowledge, and APCo has employed various personnel who have such skill and knowledge.

The Energy Services Business requires specialized knowledge of the ISO-NE and the energy markets in Northern Maine. APCo has contracted the services of four personnel who previously performed these services for the vendor of the Energy Services Business.

The electrical distribution service business of Liberty Energy requires specialized knowledge of electrical utility distribution systems and its various components. Liberty Energy has contracted the services of 41 employees that previously operated and maintained Calpeco’s electrical distribution network. In addition Calpeco has also recruited qualified individuals from within APCo and Liberty Water that have experienced operating regulated utilities and electrical generation facilities.

3.5 Competitive Conditions

APUC competes for projects and acquisitions with individuals, corporations and institutions (both Canadian and foreign) which are seeking or may seek investments similar to those desired by APUC. Availability of investment funds and an increase in interest in these investments may increase competition for them, thereby increasing purchase prices or development costs. Many of these investors have greater financial resources than those of APUC or operate according to more flexible conditions.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric power is not subject to commodity fuel price volatility or risk. In addition, the generation of hydroelectric power does not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind and water. Taking into account capital costs, wind power is generally more expensive than traditional forms of generated power. Fossil fuels are harmful to the environment, and waste burning power generation requires producers to abide by stringent and costly environmental regulations.

With deregulation and opening of competition in the electricity marketplace, there should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The US Department of Energy (“**DEP**”) has suggested that in a competitive marketplace, utilities and energy marketers will utilize Green Power pricing to strengthen their image with their customers and build customer loyalty. Further, the DEP has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The DEP believes that as deregulation and open competition evolve, the Green Power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation.

Though programs and policies are evolving at all government levels, the trading of greenhouse gas credits created by renewable energy projects is seen as part of the eventual solution.

APCo believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects.

APCo is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources. It has experience and knowledge in the area. APCo will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. APCo anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being supported by virtually every Canadian Province and a significant number of U.S. States.

Liberty Utilities is the holding company for APUC's utilities businesses. The primary focus of Liberty Utilities is the acquisition of regulated utilities in the water, wastewater, electric transmission and distribution and natural gas distribution businesses. These businesses have geographic monopolies in their service territories and are therefore insulated from competition. Liberty Utilities has developed in-house significant regulatory expertise in order to effectively deal with the state regulators in the various jurisdictions in which it operates.

3.6 Environmental Protection

The APUC Businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, policies and legislation. Failure to operate the APUC Businesses in strict compliance with these regulatory standards may expose the APUC Businesses to claims, clean-up costs and loss of operating licences and permits.

APUC has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters.

Environmental protection requirements did not have a significant financial or operational effect on APUC's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2010. However it is expected that certain regimes will impact APUC, in terms of increased expenditures, and that these will not affect the competitive position of APUC. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets are expected to increase the earnings and benefit the competitive position of APUC.

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies. APCo has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APCo has not recorded any contingent liabilities on its financial statements.

To manage these risks responsibly, APUC has ensured the Environmental and Compliance departments have been established within the different subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating Facilities are in compliance with environmental regulations and preparing regulatory submissions as required. In the aggregate, the departments comprise 7 full time equivalent positions based out of head office and have an annual budget of approximately $1.0 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

APUC and its subsidiaries have procedures to prevent and minimize any impact of possible oil spills and soil contamination that meet generally accepted industry practices. APCo's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

3.7 Employees

APUC has 15 employees involved in the management of the corporation. APCo currently has 79 employees who are involved in the operation of the renewable energy facilities, 17 employees who provide technical, environmental and safety services to APUC, an additional 52 employees through its subsidiaries who are involved in the operations of the thermal Facilities, 29 employees who are involved in management and 5 employees involved in energy marketing. Labour relations have been stable to date and there has not been any disruption in operations as a result of labour disputes with employees. With the exception of 45 employees at the EFW Facility and 6 employees at the Tinker Facility, the employees of APCo entities are non-unionized.

Liberty Utilities, which provides managerial expertise to Liberty Water and Liberty Energy currently has 6 employees. In addition, Liberty Water currently has 124 employees. Liberty Energy currently employs approximately 50 employees. With the exception of 41 employees at the California Utility, the employees of Liberty Utilities employees are non-unionized

3.8 Foreign Operations

For 2010, 59% of the gross revenue of APUC was generated in the United States. As at March 31, 2011, APUC has interests in 50 facilities located in the United States, including 19 water distribution and wastewater treatment facilities.

Currency fluctuations may affect the cash flow that APUC will realize from its operations, as certain APUC Businesses sell electricity in the United States and receive proceeds from such sales in US dollars. Such APUC Businesses also incur costs in US dollars.

3.9 Intangible Properties

The "Algonquin" name and trademark and related marks and designs are licenced to APUC by APC under a non-exclusive, royalty-free trademark licence agreement dated December 23, 1997 between APC and APUC. APUC, by using the "Algonquin" name, has the benefit of the goodwill and recognition associated with APC and its affiliates' use of the "Algonquin" name in the energy sector for the past thirteen years.

The trademark "Liberty Water" and the water drop logo for Liberty Water has been registered as a trademark and as a service mark to Liberty Water Co. The trademark and water drop logo have been licensed to the subsidiaries of Liberty Water Co. Also, as discussed in "Liberty Water Chain" above, these subsidiaries have trade name, business name or "doing business as" registrations that allow them to conduct business under the name "Liberty Water". These registrations are significant to the brand name recognition of the APUC Business that is Liberty Water.

APUC is in the process of taking out additional intellectual property right protection for the other marks and names used in the conduct of the APUC Businesses.

3.10 Cycles and Seasonality

Based on the type of PPAs in place at all of the Facilities in which APUC has an interest, the revenue generated by the Facilities is proportional to the amount of electrical energy generated.

(a) Power Generation - Hydrology

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Due to the geographic diversity of the facilities, variability of total revenues will be minimized.

(b) Power Generation - Wind

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of any wind farm. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For the Energy Services Business, demand for energy is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served by Algonquin Energy Services is located in a "winter peaking" region.

(c) Water Utilities

For Liberty Water, demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues. Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

(d) Electric Utilities

For Liberty Electric, demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Liberty Electric provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

3.11 Customers

The APUC Businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2010, APUC Businesses' revenues were derived as follows: Manitoba Hydro - approximately 10.8%; Hydro-Québec - approximately 11.2%; PG&E – approximately 8.6%; water distribution and wastewater treatment facilities – approximately 21%; waste disposal fees – approximately 5% and others - approximately 35%.

3.12 Economic Dependence

The largest customer on a percentage basis is Hydro-Québec which totalled 11.2% of gross revenues in the year ended December 31, 2010. This customer maintains an A+ S&P rating and receivables are invoiced monthly and generally collected within 30 days.

Similarly, the second largest customer on a percentage basis is Manitoba Hydro which totalled 10.8% of gross revenues in the year ended December 31, 2010. This customer maintains an AA S&P rating and receivables are invoiced monthly and generally collected within 20 days.

Otherwise, APUC does not believe it is substantially dependant on any single contractual agreement or set of related agreements either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or licence or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

3.13 Social or Environmental Policies

APUC has safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into APUC's Safety Mission Statement and Employee manual.

APUC has an Environmental, Health and Safety Group that reports independently to the President. This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

4. RISK FACTORS

The following are certain risk factors relating to the APUC Businesses. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this AIF and the documents incorporated by reference herein.

4.1 Treasury Risk Management

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that each of APCo, Liberty Water and Liberty Energy maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter.

(a) Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC Businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 45% of EBITDA and 60% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately $15.5 million and increased reported expenses from U.S. operations of approximately $11.5 million or a net impact of $4.0 million ($0.038 per Common Share) on an annual basis.

This risk has historically been managed through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. In 2009, APUC has determined that the practice of hedging 100% of its U.S. currency exposure was no longer appropriate and has unwound its existing forward currency contract program. As at March 15, 2011, APUC had no remaining forward currency hedges. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

APUC took steps in the year ended December 31, 2010 to enter into long term debt facilities denominated in U.S. funds to create natural hedges against its U.S. operations.

(b) Market price risk

The majority of APCo's electricity generating facilities sell their output pursuant to long term PPAs. However, certain of APCo's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each $10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of $1.0 million on an annualized basis.

(c) Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables. APUC does not believe this risk to be significant as approximately 72% of APCo Renewable Energy division's revenue, approximately 70% of APCo Thermal Energy division's revenue, and over 56% of APUC's total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	20,500	25%
Manitoba Hydro	AA	19,700	24%
Ontario Electricity Financial Corporation	A+	8,400	10%

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Maine Public Service		4,600	6%
National Grid	A-	3,100	4%
Public Service Company of New Hampshire	BBB	2,800	3%
Total		**$ 59,100**	**72%**
Thermal Energy Division			
Pacific Gas and Electric Company	BBB+	15,700	25%
Regional Municipality of Peel	AAA	14,500	23%
Ahlstrom	1R3	11,400	18%
Connecticut Light and Power Company	BBB	5,800	9%
Total		**$ 47,400**	**70%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2011

The remaining revenue is primarily earned by Liberty Water. In this regard, the credit risk related to Liberty Water accounts receivable balances of U.S. $5.0 million is spread over approximately 70,000 customers, resulting in an average outstanding balance of approximately $72.00 per customer. Liberty Water has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

Liberty Energy's customer base is primarily residential with exposure to large commercial accounts limited to below 20% of gross revenues. The existing commercial customers primarily consist of ski resorts, hotels, hospitals, schools and grocery stores with no single customer accounting for more than 3.6% of annual sales volume.

(d) Interest rate risk

APUC has a number of project specific and other credit facilities that are subject to a variable interest rate. These credit facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

(i) Power Generation

APCo's project debt at the Long Sault Rapids and Chuteford Facilities are subject to a fixed rate of interest and thus are not subject to interest rate risk.

The Senior Credit Facility had a balance of $64.5 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.6 million annually. The fixed for floating interest rate swaps in an amount of $100.0 million which reduces volatility in the interest expense expired on December 31, 2010. At December 31, 2010, the mark to market value of the interest rate swap was a nil (December 31, 2009 – net $3.3 million liability).

Project debt at the St. Leon Facility had a balance of $68.8 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.7 million annually. Although the underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank's prime rate, APCo has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt's interest and principal repayment schedule. This minimizes volatility in the interest expense on this debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. APCo has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2010, the mark-to-market value of the interest rate swap was a net liability of $5.4 million (2009 – net liability of $5.0 million).

Project debt at the Sanger Facility has a balance of U.S. $19.2 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.2 million annually.

(ii) Water Utilities

Liberty Water's project debt at the Litchfield and Bella Vista Facilities are subject to a fixed rate of interest and thus is not subject to interest rate risk.

On December 22, 2010 Liberty Water entered into a U.S. $50 million private placement debt financing. The notes are senior unsecured with a 10 year term bearing a fixed rate of interest at 5.6%. The notes are interest only until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. As Liberty Water's senior notes are subject to a fixed rate of interest, they are not subject to interest rate risk. The proceeds of these notes was used to reduce short term borrowings on the Senior Credit Facility.

(iii) Electrical Utilities

On December 29, 2010, Liberty Energy entered into a U.S. $70 million senior unsecured private debt placement at the California Utility. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes. The proceeds of these notes was used to the partially fund the acquisition of the California Utility.

As Liberty Energy's senior notes are subject to a fixed rate of interest, they are not subject to interest rate risk.

(e) Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

During the year ended December 31, 2010, APUC paid a dividend of $0.24 per Common Share per year. On March 3, 2011, the Board approved an annual dividend increase of $0.02 per Common Share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per Common Share. Based on the level of dividends paid during the twelve months ended December 31, 2010, cash provided by operating activities exceeded dividends declared by 2.0 times.

Subsequent to the year end, APCo concluded negotiations with its bank syndicate on the renewal of the Senior Credit Facility for a three year term with a maturity date of February 14, 2014. APCo reduced the total borrowing capacity of the Senior Credit Facility as part of its capital structure initiatives to term out some of the short-term borrowings under the Senior Credit Facility. Under the terms of the new banking agreement, as at December 31, 2010, APCo had $44.4 million of committed and available bank facilities remaining and $5.1 million of cash resulting in $49.5 million of total liquidity and capital reserves.

The U.S. $50 million debt financing entered into by Liberty Water on December 22, 2010 was used to reduce outstanding borrowings on the Senior Credit Facility. APUC is looking to reduce its level of short term borrowings under the Senior Credit Facility by way of obtaining long term debt at APCo through refinancing certain project specific financings or additional medium to long-term notes.

Credit facilities and project specific debt total approximately $257.4 million. In the event that APUC was required to replace the Senior Credit Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

(f) Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Energy is exposed to energy purchase price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

The Sanger Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $1.0 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $1.2 million or a net increase in operating profits of approximately $0.2 million.

The Windsor Locks Facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $1.0 million on an annual basis. However, historically, changes in the price of natural gas are generally matched with changes in market electricity prices which should result in a minimal impact on operating profit.

The BCI Facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $0.1 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $0.2 million or a net increase in operating profits of approximately $0.1 million.

The Energy Services Business provides the short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 130,000 MW-hrs in fiscal 2011. In the event that the Energy Services Business was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $1.3 million on an annualized basis.

This risk is mitigated though the use of short-term financial energy hedge contracts. Subsequent to December 31, 2010, APCo entered into a financial energy hedge contract to acquire approximately 215,000 MW-hrs of energy over a three year period starting March 1, 2011 at an average rate of approximately $50 per MW-hr.

The California Utility provides electric service to the Lake Tahoe basin and surrounding areas at rates approved by the CPUC. Calpeco purchases the energy requirements for its customers from NV Energy at rates reflecting its system average costs. In the event that these rates change, each $10.00 change per MW-hr would result in a change in expense of approximately U.S. $5.4 million on an annualized basis.

This risk is mitigated though ECAC, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

(g) Risk of Default under Senior Credit Facility

As security for repayment of the Senior Credit Facility, APCo has, among other things, pledged the shares and other equity interests of certain of its subsidiaries. In addition to the amount outstanding under the Senior Credit Facility as described above, APCo has posted certain letters of credit totaling $33.1 million as security for obligations of the APCo businesses. The terms of the Senior Credit Facility require APCo to pay a standby charge calculated as one quarter of the current stamping fee on the unused portion of the Senior Credit Facility and maintain certain financial covenants.

If the Senior Credit Facility goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their security.

4.2 Operational Risk Management

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

(a) Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of each of APUC’s Businesses. Accordingly, dividends to shareholders are dependent upon the profitability of each of APUC’s Businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

The water distribution networks of the Liberty Water operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

Electricity distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo, Liberty Water and Liberty Energy) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

(b) Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC's Businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its financial statements.

Generally, APCo's hydroelectric facilities are subject to some form of a water use agreement. The terms of these agreements vary by facility as they are agreements made with the local government body that regulates electrical energy generators and can extend over many years. Certain of the agreements contain clauses which allow the regulating body the option to require APCo to decommission the facility upon the expiry or termination of the agreements. Other facilities have no specific obligations other than to maintain the facility in good working order. APCo has options in many of its existing water use agreements to renew or extend the agreements and anticipates being in a position to extend the majority of its agreements and continue to operate its facilities. Based on historical general practice within the regions in which APCo has facilities, APCo has assessed the probability of being required to decommission a facility upon the expiry of a water use agreement to be remote. As such, any potential asset retirement obligation expense has been assessed as insignificant as the obligation would be incurred well into the future and there is a remote likelihood of being required to decommission a facility.

The St. Leon Facility does not own the property on which its turbines are located. In 2004, St. Leon entered into long-term right-of-way agreements with land owners which allowed it to construct and maintain the wind turbines used by the facility on their property. These agreements are for minimum terms of 40 years and, upon expiry or termination, provide the land owners with title to the equipment if it is not decommissioned by APCo at its option. While APCo anticipates being in a position to renew or extend the existing PPA in 2025, in the event that APCo is unable to renew or extend the agreement, or identify another purchaser of the energy, APCo may choose to decommission the facility. APCo has assessed there to be a remote likelihood of incurring any cost to decommission the wind farm.

The EFW Facility owns the property on which its facility operates. EFW's current waste incineration agreement expires in 2012 with two five year options to extend. While APCo anticipates being in a position to renew or extend the existing contract in 2012, in the event that APCo is unable to renew or extend the agreement, APCo may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

Liberty Water's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Water has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging wastewater treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus Liberty Water is allowed to earn a return on its investment.

Liberty Energy's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Energy has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging electricity distribution facilities and expenses associated with providing new sources of electricity can generally be included in the facility's rate base and thus Liberty Energy is allowed to earn a return on its investment.

(c) Environmental Risks

(i) Power Generation

The APCo Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric facility include possible dam failure which results in upstream or downstream flooding and equipment failure which result in oil or other lubricants being spilled into the waterway. In addition, the operation of a hydroelectric facility may cause the water in the associated waterway to flow faster, or slower, which could result in water flow issues which impact fish population, water quality and potential increases in soil erosion around a dam facility. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility. Federal regulators in the U.S. inspect certain hydroelectric facilities on an annual basis and complete an environmental inspection every 3-5 years.

The primary environmental risks associated with the operation of a wind farm include potential harm to the local and migratory bird population, potential harm to the local bat population as well as concerns over noise levels and visual 'harm' to the scenic environment around the wind farm. As part of the federal and provincial approval of the St. Leon wind project, certain pre-construction and post construction monitoring studies were required. No significant issues were identified as a result of these studies. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility.

The APCo Thermal Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a cogeneration facility include potential air quality and emissions issues, soil contamination resulting from oil spills and issues around the storage and handling of chemicals used in normal operations. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs regular stack testing and tests the calibration of monitoring equipment. The primary environmental risks associated with the operation of an incineration facility include potential air quality, odour and emissions issues, soil contamination resulting from oil or other chemical spills and issues around the storage and handling of municipal solid waste. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

(ii) Water Utilities

Liberty Water faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a wastewater treatment facility include potential air quality and odour management issues, wastewater spills and surface and ground water contamination. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Water maintains ongoing sampling and testing programs as required in its operational jurisdiction, including annual field investigations by management. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the wastewater collection system and at the wastewater treatment plants that it operates.

The primary environmental risks associated with the operation of a water distribution facility include risk of groundwater contamination by contaminants such as bacterial, synthetic, organic and inorganic pollutants, consumption and availability of groundwater and ensuring water quality continues to meet and exceed Environmental Protection Agency (“**EPA**”) and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Water maintains a regular sampling and testing program as required in its operational jurisdiction. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the water distribution systems that it operates.

Federal drinking water legislation in the United States requires all drinking water systems to meet specific standards. The costs of complying with drinking water standards form part of a facility’s rate case applications.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

(iii) Electrical Utilities

Liberty Energy faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Energy generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Energy investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

(iv) Specific Environmental Risks

(1) Greenhouse Gas Initiatives

Several north-eastern U.S. States have formed a coordination group to develop a multi-state green house gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative ("**RGGI**"), has received backing from states where APCo operates facilities including Connecticut. RGGI drafted a model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program will be implemented to regulate CO_2 emissions from large electrical generation facilities, including the Windsor Locks Facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks Facility is the only APCo site that is currently affected by the RGGI regulations. As such APCo will be required to purchase approximately 250,000 tons of CO_2 allowances per year, equivalent to the total annual CO_2 emissions from the Windsor Locks facility for the 2009 to 2012 fiscal years. APCo is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. APCo submitted an application on October 31, 2008 for allowances under the available programs. For 2010, APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks Facility to be between $0.2 and $0.4 million.

RGGI has been working since 2009. The first compliance period is from January 2009 to December 2011. The Windsor Locks Facility produced 221,522 tons of CO_2 in 2009 and 189,124 tons in 2010. The Facility was allocated amounts under the Useful Thermal Set-Aside Energy Account ("**UTSA**") (approximately 50,000 tons of CO_2 per year) in both years. The Facility purchased additional allowances at $2.00/ton through the PPA agreement and at auctions. The Windsor Locks Facility purchased allowances for $357 in 2009 and $163 in 2010. For 2011, it is estimated that the Facility will produce 205,000 tons of CO_2, obtain allowances of 55,000 tons through the UTSA, and be required to purchase an additional 95,000 tons to comply with RGGI by the end of December. The Windsor Locks Facility purchased $189 of allowances at the auction of March 9, 2011 and anticipates purchasing approximately another $180 by December, assuming the current average price of $1.90/ton.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called the Western Climate Initiative. This group recently released details of its Regional Cap-and-Trade Program, which is scheduled to start on January 1, 2012. Each member state/province is now responsible for developing the draft design of the Regional Cap-and-Trade Program and taking the necessary steps to implement the Program within its jurisdiction. APCo owns and operates the Sanger Facility in California and the EFW Facility in Ontario and holds investments in two others in Ontario which could be impacted by this program. As this process has just begun, it is too early to determine the potential financial impact on APCo and means available to mitigate this financial impact, if any.

The Carbon Disclosure Project ("**CDP**") is an independent non-profit organization that represents institutional investors managing over $57.0 trillion of assets. The CDP is specifically working to encourage companies worldwide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both potential physical impacts and regulatory changes that may result in an effort to address climate change.

APCo submitted a baseline greenhouse gas emissions inventory to the CDP for 2008 and 2009. The inventory is presently being done for 2010. The emissions data includes both direct emissions from our processes as well as indirect emissions from purchased power. The emissions inventory has been developed based on guidance from the Greenhouse Gas Protocol. This submission will allow comparisons with other firms to be made, and will also be useful as a baseline for addressing climate change regulations. Results are available on the CDP website.

(2) Renewable Energy Division

As a result of certain legislation passed in Québec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Québec.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates four hydroelectric facilities in Ontario. While it is too early to assess the costs of compliance, it is possible that modifications to certain dam structures may be required in order to be compliant with any new regulations should they come into effect. Any capital costs associated with the anticipated modifications are expected to be significantly lower than the expected capital costs related to the Québec Facilities, as there are fewer facilities in Ontario and they are of newer construction.

(3) Water Utilities

Liberty Water owns and operates the Litchfield Facility where groundwater pollutants, namely trichloroethylene (“**TCE**”) originally employed by a former aerospace manufacturing plant in the nearby City of Goodyear are progressing toward three of the twelve wells that provide water to the Litchfield service area. The EPA began monitoring TCE in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA regular technical meetings in regards to this monitoring program, The Litchfield Facility closely monitors its wells for this groundwater pollutant through the sampling and testing of water from wells that are potentially at risk of contamination. To date there have not been any detectable levels of TCE in the water from wells used by the Litchfield Facility. EPA’s monitoring and control efforts have not indicated that the concentrations are being reduced or fully captured. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are underway. In the event that any wells exceed EPA permitted TCE level, the Litchfield Facility would undertake the appropriate actions which may include installing appropriate treatment facilities or removing the well from the water distribution system of the utility. In the event of removal of a well, there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of the Litchfield Facility’s customers. In addition, the Litchfield Facility has identified alternate sites where replacement wells can be established to replace this potential lost capacity. The cost of establishing a new well is estimated to be between U.S $2.0 million and U.S. $3.5 million depending on the location, depth and other factors. The cost of commissioning a well forms part of the rate base for the utility. Other factors that can impact the cost of a well include, but are not limited to, any requirement to construct wellhead treatment for pollutants, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Water does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2010.

(v) Regimes that Could Impact APUC

(1) Power Generation

As a result of certain legislation passed in Quebec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. See "*Specific Environmental Risks*" under "*Risk Factors*".

(2) Electrical Utilities

The State of California is considering legislation that will increase the Renewable Portfolio Standards to 33% from the current 20% by the year 2020 which could impact the source of electricity for Calpeco. Any increases in cost of electricity will be passed on the ratepayers through the General Rate Case process.

(vi) Regimes that Could Benefit APUC

The US Federal government has committed to implementing a US carbon reduction strategy, and has included revenue from a federal carbon cap-and-trade program in future budget projections. Similarly, the Canadian federal and provincial governments have indicated increased support for Canadian participation in an integrated North American climate change program.

APUC believes that with its existing portfolio of renewable energy and high efficiency cogeneration Facilities the Power Generation business unit is ideally situated to benefit from an improved competitive position within the North American power sector.

In addition, the US Federal government is currently debating the implementation of a country-wide Renewable Energy Portfolio Standard. This would increase the market demand for renewable energy and broaden the opportunities for development of renewable energy projects.

In conjunction with the development of cap and trade programs and working to increase the supply of renewable energy, various North American governments are making legislative and regulatory changes to streamline the approvals process for the development of new renewable energy projects.

(d) Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various lawsuits, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

As discussed below under "Legal Proceedings", APCo and APC are involved in civil proceedings and bankruptcy proceedings with Trafalgar. As also discussed in that section, the Attorney General of Québec ("**Québec AG**") filed suit in 1996 in Québec Superior Court and claimed $5.4 million for amounts that an Algonquin entity had been paying to the federal authority under its water lease. Both proceedings have gone to the appeal stage. On the Trafalgar civil proceedings file, the claims against APCo were dismissed on appeal, and the bankruptcy proceedings continue. On the Côte Ste-Catherine Water Lease Dues file, the appeal was heard in January 2011 but the decision has not been rendered. If the Québec AG is successful in final appeal on the Côte Ste-Catherine case, an adjustment and/or increase of the amount of dues payable under the water lease is possible

(e) Tax Related Risks

Although APUC is of the view that all expenses being claimed by APUC are reasonable and that the cost amount of APUC's depreciable properties have been correctly determined, there can be no assurance that Canada Revenue Agency or the Internal Revenue Service will agree. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to shareholders.

(f) Tax risks Associated with the Unit Exchange

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of the Corporation or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange for APUC. While APUC is confident in its position, such a challenge or legislation could potentially and materially affect the availability or amount of the tax attributes or other tax accounts of APUC.

(g) Obligations to Serve

Liberty Water's and Liberty Energy's Facilities may be located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Water and Liberty Energy may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

4.3 Regulatory Climate and Permitting Risks

(a) Power Generation

Profitability of APUC businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue. The failure to obtain all necessary licences or permits, including renewals thereof or modifications thereto, may adversely affect cash generated from operating activities.

In the United States, FERC issues licences for the construction, operation and maintenance of electrical generating facilities. Facilities are required to be licenced or have valid exemptions from FERC. Failure to maintain such licences, including amendments or modifications thereto, may result in the owner being unable to operate the licenced facility and could adversely affect cash generated from operating activities.

The US Thermal Facilities obtain certain benefits and exemptions because of their Qualifying Facility status ("**QF Status**") under PURPA. If any facility were to lose its QF Status, the Facility would no longer be entitled to the exemptions and benefits thereof. Loss of QF Status may also require the Facility to cease selling electricity at the rates set forth in the existing PPAs to the extent they exceed current short run Avoided Costs. Under certain circumstances, loss of QF Status on a retroactive basis could lead to, among other things, claims by an electrical utility's end user customers for a refund of payments previously made.

(b) Water Utilities

Liberty Water's facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Water and wastewater utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Water, and while Liberty Water believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Water regularly works with these authorities to manage the affairs of the business.

(c) Electrical Utilities

Liberty Energy's facility is subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Energy, and while Liberty Energy believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Energy regularly works with these authorities to manage the affairs of the business.

4.4 Dependence upon APUC Businesses

APUC is entirely dependent upon the operations and assets of APUC Businesses. Accordingly, dividends to shareholders are dependent upon the ability of each of the APUC Businesses to pay principal and interest on the notes issued by it and to declare and pay dividends or distributions.

(a) Power Generation

The profitability of APCo's Businesses may be affected by expiry of the present long-term PPAs to which certain of APCo's Businesses are a party.

(b) Water Utilities

US governmental authorities have the ability to impose restrictions on water usage during drought conditions. If imposed, this could result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Water distribution and wastewater treatment facilities could also be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Water, and while Liberty Water believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

(c) Electrical Utilities

US governmental authorities have the ability to impose restrictions on electricity usage during periods of power generation disruption and loss of adequate transmission capability. If imposed, this could result in decreased demand for electricity, even if supplies are adequate, which could adversely affect revenues and earnings.

Electricity distribution facilities could also be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Energy, and while Liberty Energy believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

4.5 Safety Considerations

The operation of the Facilities require adherence to safety standards imposed by regulatory bodies. Failure to operate the facilities in strict compliance with these regulatory standards may expose the Facilities to claims and administrative sanctions. To mitigate the risk of administrative sanctions and to minimize safety risks to employees and contractors, APUC works continuously with all employees to ensure the development and implementation of a progressive, proactive safety culture within all operations. APUC has multiple active safety committees operating with each operating unit and has a dedicated staff to ensure that the existing safety program is continuously improving.

4.6 Labour Relations

While labour relations have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment cannot be assured.

(a) Power Generation

With the exception of the EFW Facility and the Tinker Facility, employees of APCo and their material subcontractors are non-unionized. The EFW Facility is unionized and a new collective bargaining agreement was renegotiated in 2008 for a term of 3 years, until April 2011. The Tinker Facility is unionized and a new collective bargaining agreement was renegotiated in January 2011 for a term of 5years.

(b) Liberty Water

All employees of Liberty Water and their material subcontractors are non-unionized.

(c) Liberty Energy

All employees of Liberty Energy are non-unionized with the exception of 41 employees at the California Utility. The California Utility is unionized and the current collective bargaining agreement was renegotiated in August 2010 for a term of 3 years, until August 2013.

4.7 Dependence Upon Key Customers

The customers that currently purchase APUC's Facilities are primarily large utilities. See the summaries of the contracts in Schedules A, B, C and D. If, for any reason, such customers were unable to fulfill their contractual obligations under the PPAs, distributable cash available to Shareholders would decline.

4.8 Potential Conflicts of Interest

As discussed in "*Developments in Fiscal 2009*" in "*Three Year History*" above, agreement was reached on December 21, 2009 to internalize management. Unitholders had previously been dependent on APMI for the administration of the Fund and for management and operation of the Facilities. Since December 21, 2009, management of Algonquin has been conducted by officers of APUC. There may be situations in which conflicts of interest may arise between the Senior Officers of APUC in relation to the interests of APUC. Transactions involving related parties, including the Senior Officers who are principals of APMI, are disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the period ended December 31, 2010.

4.9 Construction / Development Risk

Successful development of wind and other energy projects are subject to significant risks and uncertainties including those relating to the ability to obtain financing on acceptable terms, currency fluctuations affecting the cost of major capital components such as turbines, price escalation for construction labour and other construction inputs, construction risk that the project is built with mechanical defects, is not completed on time and is not within budget estimates.

4.10 Acquisitions and Divestitures

Acquisitions of complementary businesses and technologies are a part of APUC's overall business strategy. In spite of the complementary nature of any businesses or technologies acquired, there is always a risk that services, technologies, key personnel or businesses of acquired companies may not be effectively assimilated into APUC's business or service offerings. Similarly, divestitures of businesses that are no longer viewed as being strategic to APUC's continuing operations can be an active part of APUC's overall business strategy. Divestitures may result in a reduction in total revenues and net income.

5. DIVIDENDS/DISTRIBUTIONS

The total amount of dividends/distributions declared for fiscal 2008, 2009 and 2010 were $57.8, $19.3 and $22.8 million, respectively. The amount of dividends/distributions declared for each Trust Unit or Common Share of the Fund for fiscal 2008, 2009 and 2010 were $0.75, $0.24 and $0.24, respectively.

Since January 1, 2010, APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective March 3, 2011, the Board established a quarterly dividend of $0.065 or $0.26 annually.

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time in its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors noted above. See "*Risk Factors*".

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 Common Shares

APUC is authorized to issue an unlimited number of Common Shares. The holders of Common Shares are entitled to one vote per Common Share at meetings of the shareholders of the Corporation and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC.

As at December 31, 2010, APUC had 95,422,778 issued and outstanding Common Shares on a fully diluted basis. On January 1, 2011, following Emera's exercise of its subscription receipts, APUC had 103,945,778 issued and outstanding Common Shares on a fully diluted basis. The Common Shares issued to Emera were in connection with APUC's partnership with Emera entered into on April 23, 2009 wherein APUC agreed to issue approximately 8.5 million Common Shares of APUC at a price of $3.25 per Common Share to finance a portion of the acquisition of the California Utility. As at March 15, 2011, APUC had 103,988,335 issued and outstanding Common Shares on a fully diluted basis. Subsequent to December 31, 2010, Series 1A Debentures valued at approximately $72 were converted to 17,558 Common Shares and Series 3 Debentures values at approximately $105 million were exchanged for 24,999 Common Shares.

6.2 Preferred Shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in series. There are no preferred shares issued or outstanding.

6.3 Convertible Debentures

APUC currently has outstanding three series of convertible debentures:

- a principal amount of $62,398 pursuant to 7.50% convertible unsecured subordinated debentures due November 33, 2014 at a price of $1,000 per debenture (the "**Series 1A Debentures**");
- a principal amount of $59,967 pursuant to 6.35% convertible unsecured subordinated debentures due November 30, 2016 at a price of $1,000 per debenture (the "**Series 2A Debentures**"); and
- a principal amount of $62,800 pursuant to 7.00% convertible unsecured subordinated debentures due June 30, 2017 at a price of $1,000 per debenture (the "**Series 3 Debentures**").

If all of the principal amount of the Series 1A Debentures, the Series 2A Debentures and the Series 3 Debentures (the "**APUC Debentures**") were converted by the holders thereof, an additional 40,830,923 Common Shares will be issued pursuant to the terms of the trust indenture (the "**Trust Indenture**") dated as of October 27, 2009 between the APUC and CIBC Mellon Trust Company (the "**Debenture Trustee**") with respect to the Series 1A Debentures and the Series 2A Debentures and the terms of the trust indenture (the "**Series 3 Trust Indenture**") dated as of December 2, 2009 between APUC and the Debenture Trustee.

(a) Series 1A Debentures

In July 2004, the Fund issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on July 31, 2011 ("**Series 1 Debentures**"). On October 27, 2009, there were 84,964 convertible debentures outstanding with a face value of $84,964. On October 27, 2009, $63,755 of the outstanding Series 1 Debentures was exchanged for the Series 1A Debentures in a principal amount of $66,943. The remaining Series 1 Debentures having a face value of $21,209, not converted to Series 1A Debentures were exchanged for 6,607,027 Common Shares.

The Series 1A Debentures pay interest semi-annually in arrears on January 1 and July 1 each year. As at March 15, 2011, there were 62,398 Series 1A Debentures outstanding with a face value of $62,398.

(b) Series 2A Debentures

In November 2006, the Fund issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016 ("**Series 2 Debentures**"). On October 27, 2009, there were 59,967 Series 2 Debentures outstanding with a face value of $59,967. On October 27, 2009, all of the outstanding Series 2 Debentures were exchanged for Series 2A Debentures in a principal amount of $59,967.

The Series 2A Debentures pay interest semi-annually in arrears on April 1 and October 1 each year. As at March 15, 2011, there were 59,967 Series 2A Debentures outstanding with a face value of $59,967.

(c) Series 3 Debentures

On December 2, 2009, APUC issued 63,250 Series 3 Debentures. The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year. As at March 15, 2011, there were 62,800 Series 3 Debentures outstanding with a face value of $62,800.

APUC may, from time to time, without the consent of the holders of the APUC Debentures, issue additional debentures. For a complete description of the APUC Debentures, reference should be made to the Trust Indenture and the Series 3 Trust Indenture, copies of which are available on www.sedar.com.

(i) Conversion Privilege

The Series 1A Debentures are convertible at the holder's option into fully paid, non-assessable and freely tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of November 30, 2014 (the "**Series 1A Maturity Date**") and the business day immediately preceding the date specified by APUC for redemption of the Series 1A Debentures, at a conversion price of $4.08 per Common Share (the "**Series 1A Conversion Price**"), being a ratio of approximately 245.1 Common Shares per $1,000 principal amount of Series 1A Debentures. The Series 1A Debentures bear interest from the date of issue at 7.50% per annum, which will be payable semi-annually on July 1 and January 1 in each year, which commenced on January 1, 2010 (each, a "**Series 1A Interest Payment Date**").

The Series 2A Debentures are convertible at the holder's option into fully paid, non-assessable and freely tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of November 30, 2016 (the “**Series 2A Maturity Date**”) and the business day immediately preceding the date specified by APUC for redemption of the Series 2A Debentures, at a conversion price of $6.00 per Common Share (the “**Series 2A Conversion Price**”) being a ratio of approximately 166.7 Common Shares per $1,000 principal amount of Series 2A Debentures. The Series 2A Debentures bear interest from the date of issue at 6.35% per annum, which will be payable semi-annually on April 1 and October 1 in each year, commencing on April 1, 2010 (each, a “**Series 2A Interest Payment Date**”).

The Series 3 Debentures are convertible at the holder’s option into fully paid, non-assessable and freely tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of June 30, 2017 (the “**Series 3 Maturity Date**”) and the business day immediately preceding the date specified by APUC for redemption of the Series 3 Debentures, at a conversion price of $4.20 per Common Share (the “**Series 3 Conversion Price**”) being a ratio of approximately 238.1 Common Shares per $1,000 principal amount of Series 3 Debentures. The Series 3 Debentures bear interest from the date of issue at 7.0% per annum, which will be payable semi-annually on June 30 and December 31 in each year, commencing on June 30, 2010 (each, a “**Series 3 Interest Payment Date**”).

Interest will be payable based on a 365-day year. At the option of APUC, subject to applicable law, APUC may deliver Common Shares to its agent who shall sell such Common Shares on behalf of APUC in order to raise funds to satisfy all or any part of APUC’s obligations to pay interest on the APUC Debentures, but in any event, the holders of APUC Debentures shall be entitled to receive cash payments equal to the interest otherwise payable on the APUC Debentures.

No adjustment will be made for dividends on Common Shares issuable upon conversion or for interest accrued on APUC Debentures surrendered for conversion; however, holders converting their APUC Debentures are entitled to receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to the date of conversion from: (a) the latest Series 1A Interest Payment Date (in the case of the Series 1A Debentures) or (b) the latest Series 2A Interest Payment Date (in the case of the Series 2A Debentures). Notwithstanding the foregoing: (a) no Series 1A Debentures may be converted on any Series 1A Interest Payment Date and during the five business days preceding January 1 and July 1 in each year; (b) no Series 2A Debentures may be converted on any Series 2A Interest Payment Date and during the five business days preceding April 1 and October 1 in each year; and (c) no Series 3 Debentures may be converted on any Series 3 Interest Payment Date and during the five business days preceding June 30 and December 31 in each year as the registers of the Debenture Trustee are closed during such periods.

Subject to the provisions thereof, the Trust Indenture and the Series 3 Trust Indenture provide for the adjustment of the Series 1A Conversion Price, the Series 2A Conversion Price and the Series 3 Conversion Price in certain events including: (a) the subdivision or consolidation of the outstanding Common Shares; (b) the distribution of Common Shares to holders of Common Shares by way of distribution or otherwise other than an issue of securities to holders of Common Shares who have elected to receive distributions in securities of APUC in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than 95% of the then Current Market Price (as defined below under “Payment upon Redemption or Maturity”) of the Common Shares; and (d) the distribution to all holders of Common Shares of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the Series 1A Conversion Price, the Series 2A Conversion Price or the Series 3 Conversion Price, in respect of any event described in (b), (c) or (d) above if, subject to prior regulatory approval, the holders of APUC Debentures are allowed to participate as though they had converted their APUC Debentures prior to the applicable record date or effective date. APUC will not be required to make adjustments in either the Series 1A Conversion Price, the Series 2A

Conversion Price or the Series 3 Conversion Price, unless the cumulative effect of such adjustments would change the Series 1A Conversion Price, the Series 2A Conversion Price or the Series 3 Conversion Price, as the case may be, by at least 1%.

In the case of any reclassification or change (other than a change resulting only from consolidation or subdivision) of the Common Shares or in case of any amalgamation, consolidation or merger of APUC with or into any other entity, or in the case of any sale, transfer or other disposition of the properties and assets of APUC as, or substantially as, an entirety to any other entity, the terms of the conversion privilege shall be adjusted so that each APUC Debenture shall, after such reclassification, change, amalgamation, consolidation, merger or sale, be exercisable for the kind and amount of securities or property of APUC, or such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, change, amalgamation, consolidation, merger or sale if on the effective date thereof it had been the holder of the number of Common Shares into which APUC Debenture was convertible prior to the effective date of such reclassification, change, amalgamation, consolidation, merger or sale.

No fractional Common Shares will be issued on any conversion of APUC Debentures, but in lieu thereof, APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

(ii) Redemption and Purchase

During the period from January 2, 2011 to January 1, 2012, the Series 1A Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 1A Conversion Price.

On or after January 1, 2012 and prior to the Series 1A Maturity Date, the Series 1A Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

During the period from January 2, 2011 to January 1, 2012, the Series 2A Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 2A Conversion Price.

On or after January 1, 2012 and prior to the Series 2A Maturity Date, the Series 2A Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

The Series 3 Debentures may not be redeemed by APUC (except in the case of a change of control) on or before December 31, 2012. Thereafter, but prior to December 31, 2014, the Series 3 Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 3 Conversion Price.

On or after December 31, 2014 and prior to the Series 3 Maturity Date, the Series 3 Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

APUC will have the right to purchase APUC Debentures in the market, by tender or by private contract subject to regulatory requirements; provided, however, that if an Event of Default (as defined below) has occurred and is continuing, APUC will not have the right to purchase APUC Debentures by private contract.

In the case of redemption of less than all of APUC Debentures, APUC Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX.

(iii) Payment upon Redemption or Maturity

On redemption or on the Series 1A Maturity Date, the Series 2A Maturity Date or the Series 3 Maturity Date, as applicable, APUC will repay the indebtedness represented by APUC Debentures which are to be redeemed or which have matured by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding APUC Debentures, together with accrued and unpaid interest thereon. APUC may, at its option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, unless an Event of Default (as defined below) has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of APUC Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Common Shares to the holders of the APUC Debentures. The number of Common Shares to be issued will be determined by dividing the principal amount of the APUC Debentures which are to be redeemed by 95% of the Current Market Price of the Common Shares on the date fixed for redemption or the maturity date, as the case may be. No fractional Common Shares will be issued to holders of APUC Debentures but in lieu thereof APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

The term "**Current Market Price**" is defined in the Trust Indenture to mean the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event.

(iv) Cancellation

All APUC Debentures converted, redeemed or purchased as aforesaid will be cancelled and may not be reissued or resold.

(v) Subordination

The payment of the principal of, and interest on, the APUC Debentures is subordinated in right of payment, in the circumstances referred to below and more particularly as set forth in the Trust Indenture, to the prior payment in full of all Senior Indebtedness of APUC. "**Senior Indebtedness**" of APUC is defined in the Trust Indenture as all indebtedness of APUC, other than the APUC Debentures and any other debentures issued under the Trust Debenture, (whether outstanding as at the date of the Trust Indenture or thereafter created, incurred, assumed or guaranteed), and including, for greater certainty, claims of trade creditors of APUC, which by the terms of the instrument creating or evidencing the indebtedness, is not expressed to be *pari passu* with, or subordinate in right of payment to, APUC Debentures.

The Trust Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation or reorganization in connection with or as a result of an insolvency or bankruptcy proceeding or other similar proceedings relative to APUC, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding up of APUC, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of APUC, all creditors under any Senior Indebtedness will receive payment in full before the holders of APUC Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any APUC Debenture or any unpaid interest accrued thereon.

In addition to the foregoing, pursuant to the terms of the Trust Indenture, neither the Debenture Trustee for, nor the holders of, APUC Debentures are entitled to demand or otherwise attempt to enforce in any manner, institute proceedings for the collection of, or institute any proceedings against APUC, including, without limitation, by way of any bankruptcy, insolvency or similar proceedings or any proceeding for the appointment of a receiver, liquidator, trustee or other similar official (it being understood and agreed that the Debenture Trustee and/or the holders of APUC Debentures are permitted to take any steps necessary to preserve the claims of the holders of APUC Debentures in any such proceeding and any steps necessary to prevent the extinguishment or other termination of a claim or potential claim as a result of the expiry of a limitation period), or receive any payment or benefit in any manner whatsoever on account of indebtedness represented by APUC Debentures other than as set forth in the Trust Indenture at any time when (i) an event of default (howsoever designated) has occurred and is continuing under the Senior Credit Facility, or (ii) an event of default (howsoever designated) has occurred under any other Senior Indebtedness and is continuing and, in each case, notice of such event of default has been given by or on behalf of the lender or lenders party to such Senior Indebtedness to APUC or an affiliate thereof that is the borrower pursuant to such Senior Indebtedness (the "**Senior Indebtedness Postponement Provisions**").

The APUC Debentures are also subordinate to claims of creditors of APUC.

(vi) Put Right upon a Change of Control

Upon the occurrence of a change of control of APUC involving the acquisition of voting control or direction over 66 2/3% or more of the outstanding Common Shares by any person or group of persons acting jointly or in concert (a "**Change of Control**"), each holder of APUC Debentures may require APUC to purchase, on the date which is 30 days following the giving of notice of the Change of Control as set out below (the "**Put Date**"), the whole or any part of such holder's APUC Debentures at a price equal to 101% of the principal amount thereof (the "**Put Price**") plus accrued and unpaid interest to the Put Date.

If 90% or more in the aggregate principal amount of APUC Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered for purchase on the Put Date, APUC will have the right to redeem all the remaining APUC Debentures on such date at the Put Price, together with accrued and unpaid interest to such date. Notice of such redemption must be given to the Debenture Trustee prior to the Put Date and as soon as possible thereafter, by the Debenture Trustee to the holders of APUC Debentures not tendered for purchase. The principal on APUC Debentures will be payable in lawful money of Canada or, at the option of APUC and subject to applicable regulatory approval, by payment of Common Shares to satisfy, in whole or in part, its obligation to repay the principal amount of APUC Debentures.

The Trust Indenture contains notification provisions to the effect that:

(a) APUC will promptly give written notice to the Debenture Trustee of the occurrence of a Change of Control and the Debenture Trustee will thereafter give to the holders of APUC Debentures a notice of the Change of Control, the repayment right of the holders of APUC Debentures and the right of APUC to redeem un-tendered APUC Debentures under certain circumstances; and

(b) a holder of APUC Debentures, to exercise the right to require APUC to purchase its APUC Debentures, must deliver to the Debenture Trustee, not less than five business days prior to the Put Date, written notice of the holder's exercise of such right, together with a duly endorsed form of transfer.

APUC will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of APUC Debentures in the event of a Change of Control.

(vii) Modification

The rights of the holders of the APUC Debentures as well as any other series of debentures that may be issued under the Trust Indenture may be modified in accordance with the terms of the Trust Indenture. For that purpose, among others, the Trust Indenture contains certain provisions which will make binding on all holders of APUC Debentures resolutions passed at meetings of the holders of APUC Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the then outstanding APUC Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the then outstanding APUC Debentures. In certain cases, the modification will, instead of or in addition to, require assent by the holders of the required percentage of APUC Debentures of each particularly affected series. Under the Trust Indenture, the Debenture Trustee has the right to make certain amendments to the Trust Indenture in its discretion, without the consent of the holders of APUC Debentures.

(viii) Events of Default

The Trust Indenture provides that an event of default ("**Event of Default**") in respect of the APUC Debentures will occur if certain events described in the Trust Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to the APUC Debentures: (i) failure for 15 days to pay interest on the APUC Debentures when due; (ii) failure to pay principal or premium, if any, on the APUC Debentures, whether at maturity, upon redemption, by declaration or otherwise; or (iii) certain events of bankruptcy, insolvency or reorganization of APUC under bankruptcy or insolvency laws. Subject to the Senior Indebtedness Postponement Provisions, if an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall, upon the request of holders of not less than 25% in principal amount of the then outstanding APUC Debentures, declare the principal of (and premium, if any) and interest on all outstanding APUC Debentures to be immediately due and payable.

(ix) Offers for Debentures

The Trust Indenture contains provisions to the effect that if an offer is made for APUC Debentures which is a take-over bid for APUC Debentures within the meaning of the Securities Act (Ontario) and not less than 90% of the APUC Debentures (other than APUC Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the APUC Debentures held by holders of APUC Debentures who did not accept the offer on the terms offered by the offeror.

(x) Priority of Debt

The APUC Debentures are direct obligations of APUC and may not be secured by any mortgage, pledge, hypothec or other charge and are subordinated to other liabilities of APUC. The Trust Indenture does not restrict AUC from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its assets to secure any indebtedness.

6.4 Shareholders' Rights Plan

The Rights Plan is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the board of directors of the Corporation and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The Rights Plan was approved by shareholders at the Meeting until the termination of the annual general meeting of the Shareholders of APUC in 2013 or its termination under the terms of the of Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. Until the occurrence of certain specific events, the rights will trade with the Common Shares of APUC and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Rights Plan, a Permitted Bid is a bid made to all shareholders for all of their Common Shares on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent of the outstanding Common Shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Common Shares but must extend the bid for a further ten days to allow all other shareholders to tender.

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

(a) Common Shares

Common Shares are listed and posted for trading on the TSX under the symbol "AQN". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares and trust units for the periods indicated (as quoted by the TSX).

2010	High ($)	Low ($)	Volume (000's)
January	4.61	3.85	5,554,892
February	4.44	4.09	4,843,418
March	4.80	4.14	6,140,412

2010	High ($)	Low ($)	Volume (000's)
April	4.53	4.23	4,304,658
May	4.45	3.50	7,164,537
June	4.22	3.93	2,879,941
July	4.32	4.05	2,528,957
August	4.27	3.74	3,871,542
September	4.75	4.21	4,087,116
October	4.91	4.57	9,675,727
November	5.04	4.61	6,705,800
December	5.10	4.64	5,076,401

(b) Series 1A Debentures

Series IA Debentures are listed and posted for trading on the TSX under the symbol "AQN.DB". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 1A Debentures for the periods indicated (as quoted by the TSX).

2010	High ($)	Low ($)	Volume (000's)
January	112.00	107.00	5,492
February	112.00	108.00	4,011
March	117.99	109.50	23,381
April	115.00	109.01	13,889
May	110.01	102.50	10,793
June	108.65	104.50	22,366
July	110.90	107.71	34,053
August	109.01	106.76	3,165
September	116.00	109.10	22,342
October	123.02	114.09	51,254
November	124.04	114.53	67,152
December	124.75	116.44	30,933

(c) Series 2A Debentures

Series 2A Debentures are listed and posted for trading on the TSX under the symbol "AQN.DB.A". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 2A Debentures for the periods indicated (as quoted by the TSX).

2010	High ($)	Low ($)	Volume (000's)
January	105.00	101.00	4,810
February	104.50	101.00	5,560
March	108.00	101.25	8,520
April	105.00	102.75	4,230
May	104.00	95.01	4,170
June	104.90	100.00	2,650
July	104.90	101.60	4,290
August	105.00	102.01	7,380
September	106.75	104.25	3,080
October	108.00	105.00	3,560

2010	High ($)	Low ($)	Volume (000's)
November	107.85	104.10	4,400
December	106.50	103.50	3,230

(d) Series 3 Debentures

Series 3 Debentures are listed and posted for trading on the TSX under the symbol "AQN.DB.B". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 3 Debentures for the periods indicated (as quoted by the TSX).

2010	High ($)	Low ($)	Volume (000's)
January	112.38	105.00	75,240
February	110.99	106.25	17,810
March	117.00	107.50	44,545
April	112.00	107.50	10,380
May	110.00	98.46	13,750
June	106.50	103.50	14,250
July	110.00	105.00	20,480
August	108.50	105.00	14,630
September	114.90	109.00	34,110
October	118.51	112.01	26,440
November	122.00	113.55	38,110
December	122.77	114.15	23,370

7.2 Prior Sales

On August 12, 2010, a total of 1,102,041 stock options, being the only unlisted securities of the Corporation that were issued, were granted to certain executive officers of APUC as set forth below. On March 22, 2011 an additional 892,107 stock options were granted to certain executive officers of APUC as set forth below

Date of Grant	Number of Stock Options	Exercise Price	Term
August 12, 2010	1,102,041	$ 4.05	8 years
March 12, 2011	892,107	$ 5.23	8 years

8. DIRECTORS AND OFFICERS

8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC, and information on their history with the Fund. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 60	Mr. Ball is currently the Executive Vice President of Corpfinance International Limited, an investment banking boutique firm. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a Director of the Independent Power Association of British Columbia.	Director of APUC since October 27, 2009. Trustee of the Fund since October 22, 2002	24,200
KENNETH MOORE Toronto, Ontario, Canada Age: 52	Mr. Moore is currently the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., another Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation and has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director).	Director of APUC since October 27, 2009. Trustee of the Fund since December 18, 1998	18,000
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 61	Mr. Steeves is the Principal of True North Energy, an energy consulting firm. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the president of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a Chairman, director and/or audit committee member of public and private companies, including the Fund, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia.	Director of APUC since October 27, 2009. Trustee of the Fund since September 8, 1997	17,241(1)
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 53	Mr. Huskilson is currently the President and Chief Executive Officer of Emera Incorporated, a North American energy and services company. Since 1980, Mr. Huskilson has held a number of positions within Nova Scotia Power Inc, and is currently a director of Emera Incorporated, Nova Scotia Power Inc. and chairman of Bangor Hydro-Electric Company.	Director of APUC since October 27, 2009. Trustee of the Fund since July 27, 2009	nil(2)

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 51	Mr. Bronicheski is the Chief Financial Officer of APUC. He has held various senior management positions including Executive Vice President and Chief Financial Officer of a publicly traded income trust providing local telephone, cable television and internet service. He was also Chief Financial Officer for a large public hospital in Ontario. David holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA. He is also a Chartered Accountant (CA).	Officer of APUC since October 27, 2009. Officer of the Fund since September 17 2007(3) (4)	38,300(7) (8)
CHRISTOPHER K. JARRATT(5) (6) Oakville, Ontario, Canada Age: 52	Mr. Jarratt is currently the Vice Chairman of APUC. Mr. Jarratt is a founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988. Mr. Jarratt has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He holds a Professional Engineer designation and an Honours Bachelor of Science degree from the University of Guelph.	Director of APUC since June 23, 2010.	406,423(7) (8)
IAN E. ROBERTSON(5) (6) Oakville, Ontario, Canada Age: 51	Mr. Robertson is currently the President and Chief Executive Officer of APUC. Mr. Robertson is a founder and principal of Algonquin Power Corporation Inc., a private independent power developer formed in 1988. Mr. Robertson has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He received a Bachelor of Engineering from the University of Waterloo and holds the Professional Engineering designation along with a Master of Business Administration degree from York University and a Chartered Financial Analyst designation	Director of APUC since June 23, 2010.	422,708(7) (8)
MARY LOU MCDONALD Ontario,Canada Age: 48	Ms. McDonald has been general counsel for APCo since April 2008 and was appointed Corporate Secretary of APUC on March 4, 2010. Prior to her position with APCo, she was in-house legal counsel for a division of Superior Plus LP. From 2000 to 2003, Ms. McDonald was an associate at the law firm of Macleod Dixon LLP in Calgary, Alberta and prior to that worked as an associate at a boutique energy law firm. Ms McDonald attended law at the University of Calgary and was called to the bar in 1994.	Officer of APUC since March 4, 2010	1,500

Notes:

(1) Mr. Steeves' directly owns 14,327 Common Shares and Mr. Steeves' spouse owns 2,914 Common Shares. Mr. Steeves exercises control and direction over the Common Shares owned by his spouse.

(2) Mr. Huskilson does not own any Common Shares.

(3) Mr. Bronicheski became an officer of the Fund on September 17, 2007.

(4) Prior to becoming an officer of the Fund in September 2007, Mr. Bronicheski was the Chief Financial Officer of Amtelecom Income Fund from July 2003 to July 2007.
(5) Messrs. Jarratt and Robertson, together with others, collectively own all of the issued and outstanding shares of APMI.
(6) As consideration for payment of APUC's acquisition of APMI's interest in the management agreement, Mr. Robertson and Mr. Jarratt following shareholder approval at the Meeting each received 295,045 Common Shares.
(7) Messrs. Jarratt, Robertson, and Bronicheski hold 378,061, 494,388, and 229,592 stock options respectively, granted on August 12, 2010. The stock options allow for the purchase of Common Shares at a price of $4.05. One-third of the stock options vests on each of January 1, 2011, 2012 and 2013. Stock options may be exercised up to eight years following the date of grant.
(8) Messrs. Jarratt, Robertson, and Bronicheski hold 335,423, 380,146, and 176,538 stock options respectively, granted on March 11, 2011. The stock options allow for the purchase of Common Shares at a price of $5.23. One-third of the stock options vests on each of January 1, 2012, 2013 and 2014. Stock options may be exercised up to eight years following the date of grant.

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his successor is elected in accordance with the by-laws of APUC (the "**By-Laws**").

As of March 25, 2011, approximately 829,131 Common Shares representing 0.8% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by Senior Officers and approximately 925,458 Common Shares representing 0.9% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by the directors and executive officers of the Corporation.

8.2 Audit Committee

Under the By-Laws, the directors may appoint from their number committees to effect the administration of the director's duties. The directors have established an Audit Committee comprised of three of the four independent directors of APUC, Christopher Ball (Chairman), Kenneth Moore and George Steeves, all of whom are independent and financially literate for purposes of National Instrument 52-110, *Audit Committees*. The Audit Committee is responsible for reviewing significant accounting, reporting and internal control matters, reviewing all published quarterly and annual financial statements and recommending their approval to the Directors and assessing the performance of APUC's auditors.

(a) Audit Committee Charter

The charter for APUC's audit committee (the "**Audit Committee**") is attached as Schedule E to this AIF.

(b) Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as Directors of APUC, of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee.

Mr. Ball has extensive financial experience, with over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Moore has extensive financial experience and is the Managing Partner of NewPoint Capital Partners Inc., a boutique financial advisory firm focused on mergers and acquisitions. He was formerly a Vice-President at a Canadian Chartered Bank. Mr. Moore holds a Chartered Financial Analyst designation.

Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University. Mr. Steeves is the former president of Cumming Cockburn Limited and has extensive financial experience in acting as a Chairman, director and/or audit committee member of public and private companies, including the Fund, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He received a Bachelor and Masters of Engineering from Carlton University and holds the Professional Engineering designation in Ontario and British Columbia.

(c) Pre-Approval Policies and Procedures

All non-audit services proposed to be provided by APUC's auditors must be approved by the Directors prior to the auditors providing such services.

For the financial year ended December 31, 2010 and December 31, 2009, KPMG LLP charged the following fees to APUC:

Services	2010 Fees ($)	2009 Fees ($)
Audit Fees	648,000	580,000
Audit-Related Fees(1)	375,000	862,000
Tax Fees(2)	885,000	1,156,000
All Other Fees	Nil	Nil

Notes:

(1) For assurance and related services that are reasonably related to the performance of the audit or review of the Fund's financial statements and not reported under Audit Fees, including services in connection with prospectus and securities filings, accounting advice, French translation services and financial statement audits of subsidiary companies.

(2) For tax compliance, advice and planning services.

8.3 Corporate Governance and Compensation Committees

The directors have also established a Corporate Governance Committee ("**CGC**") comprised of three of the independent directors of APUC, George Steeves (chair), Chris Huskilson and Ken Moore, and management members Ian Robertson and Chris Jarratt. This CGC also serves as the director nominating and evaluating. The CGC is responsible for reviewing APUC's corporate governance practices. The CGC will also consider from time to time the effectiveness of the Directors and whether an increase to the number of directors is warranted.

The directors have also put in place a Compensation Committee, comprised of Directors Chris Huskilson (chair) and Chris Ball, and management members Ian Robertson and David Bronicheski. The Compensation Committee is responsible for reviewing directors' compensation on an annual basis, or more frequently if required, in light of the risks involved in being an effective Director. In addition, the Compensation Committee will make recommendations to the directors regarding the compensation of executive officers of APUC and produce a report concerning executive compensation in compliance with Canadian securities law requirements.

8.4 Bankruptcies

Mr. Moore was a director of Telephoto Technologies Inc., a private sports and entertainment media. Telephoto Technologies Inc. was placed into receivership in August, 2010 by Venturelink Funds. Mr. Moore resigned from the board of directors of Telephoto Technologies Inc. in April, 2010.

8.5 Potential Material Conflicts of Interest

Other than as set out below or disclosed elsewhere in this AIF and APUC's financial statements and management's discussion and analysis for the fiscal year ended December 31, 2010, APUC is not aware of any existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary. Mr. Huskilson is a director of APUC but also the President and CEO of Emera, and Emera is a shareholder of APUC, is a co-owner of Calpeco with Liberty Energy, has entered into agreement to acquire 12 million Common Shares through subscription receipts subject to certain trigger events, and is also in a strategic relationship with APUC. Mr. Huskilson does not vote in Board meetings on matters involving APUC's relationship with Emera nor on matters involving a potential conflict between APUC and Emera.

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2010 are as follows:

(a) Trafalgar

As reported in previous public filings of Algonquin, Trafalgar Power, Inc. and an affiliate (collectively, "**Trafalgar**") commenced an action in 1999 in U.S. District Court against Algonquin, APMI and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to Algonquin and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "**Trafalgar Facilities**"). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain APCo entities, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that Algonquin was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against Algonquin were dismissed by summary judgement. On October 22, 2009 Trafalgar filed an appeal from the November 6, 2008 summary judgement to the United States Court of Appeals for the Second Circuit. The Second Circuit Court of Appeals, among other things, on November 2, 2010 dismissed the claims against APCo in the civil proceedings. The bankruptcy proceedings are continuing.

(b) Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec ("**Québec AG**") filed suit in Québec Superior Court against Algonquin Développement Côte Ste-Catherine Inc. (Développement Hydromega), a predecessor company to an Algonquin subsidiary. The Québec AG at trial claimed $5.4 million for amounts that the Algonquin entity had been paying to the federal authority under its water lease with the authority. The Algonquin entity brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011. The Côte Ste-Catherine Facility currently pays water lease dues to the federal government, but if the Québec AG is successful in any appeal, an adjustment and/or increase of such amounts is possible.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2010, there have been:

(a) no penalties or sanctions imposed against APUC by a court relating to securities legislation or by a securities regulatory authority;

(b) no other penalties or sanctions imposed by a court or regulatory body against APUC that would likely be considered important to a reasonable investor in making an investment decision; or

(c) no settlement agreements that APUC has entered into with a court relating to securities legislation or with a securities regulatory authority.

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this AIF, and as disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the periods ended December 31, 2010, 2009, and 2008, management has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC.

11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Trust Units is CIBC Mellon Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, Halifax and Winnipeg.

12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of APUC and its subsidiaries, the contracts described below are the only contracts entered into by APUC or its subsidiaries during 2010 (or prior to 2009 in the case of contracts that are still in effect) that are material to APUC. It is worthy of note that Transfer Agreements dated December 21, 2009 with each of the principals of APMI that transferred their interests in the Management Agreement (as discussed in the Management Information Circular dated June 1, 2010) were approved in 2010 by the Shareholders at the Meeting as well as the TSX. The previously disclosed material contracts with Management have all been terminated as they pertain to APUC. These are the Management Agreement, the Operations Supervisory Agreement, the Administration Agreement, the Governance Agreement and the Direct Operations Agreements, all as defined in the AIF of APUC dated March 31, 2011.

(a) **Shareholder Rights Plan**: The Shareholder Rights Plan Agreement dated as of June 9, 2010 between APUC and CIBC Mellon Trust Company, as Rights Agent. The Rights Plan creates a right (which may only be exercised if a person acquires control of 20% or more of the Common Shares) for each Shareholder, other than the person that acquires 20% or more of the Common Shares, to acquire additional Common Shares at one-half of the market price at the time of exercise. Until the occurrence of certain specific events, the rights will trade with the Common Shares and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares of APUC without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of Common Shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares of APUC at a fifty percent discount to the market price at the time.

(b) **National Grid Transaction Documents:** Two Stock Purchase Agreements each entered into on December 8, 2010 and amended and restated January 21, 2011 between National Grid, as Seller, and Liberty Energy, as Buyer. One agreement is for the purchase of all issued and outstanding shares of Granite State, and the other is for all the issued and outstanding shares of EnergyNorth. The interests of Buyer in the agreements have been transferred to Liberty Energy NH. The total consideration payable is U.S. $285.0 million. Granite State is a regulated electric distribution company providing electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth is a regulated natural gas distribution utility providing natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively. The closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011.

(c) **2010 Subscription Agreement**: Offering of Subscription Receipts dated as of December 9, 2010 from APUC to Emera, in which Emera agreed to a conditional treasury subscription of 12.0 million Common Shares at a price of $5.00 per Common Share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. Payment for the 2010 Subscription Receipts will be satisfied by delivery by Emera of a non-interest bearing promissory note in the amount of $60,000,000. Upon receipt by Emera that the conditions precedent to the closing of the National Grid transactions have occurred (other than payment of the purchase price), the promissory note will become due and payable and the rights evidenced by the 2010 Subscription Receipts will be deemed to have been satisfied by the delivery of Common Shares from APUC on a one-for-one basis, subject to customary anti-dilution adjustments. In the event of termination of the 2010 Subscription Agreement, the promissory note will be returned to Emera for cancellation, and the parties will have no further obligations under the 2010 Subscription Agreement and the Subscription Receipts will be returned for cancellation.

(d) **Liberty Water Private Placement**: Liberty Water $50,000 5.60% Unsecured Notes due December 22, 2020 Note Purchase Agreement dated as of December 22, 2010, pursuant to which Liberty Water entered into a U.S. $50 million private placement debt financing. The notes are senior unsecured with a 10 year term bearing interest at 5.6%. The notes are interest only until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. The funds were used to reduce outstanding indebtedness under APCo's Senior Credit Facility.

(e) **Subscription and Unitholder Agreement** dated April 22, 2009 (the "**Subscription Agreement**") between Algonquin and Emera, pursuant to which Emera obtained a conditional treasury subscription of approximately 8.5 million trust units of Algonquin at a price of $3.25 per Trust Unit. Subsequent to the completion of the Unit Exchange, the Subscription Agreement was amended to reflect a subscription of Common Shares rather than Trust Units of Algonquin. Delivery of Common Shares under the subscription receipts to occurred simultaneously with the closing of the acquisition of the California Utility on January 1, 2011. At closing, Emera exchanged these subscription receipts into 8.532 million APUC Common Shares at a purchase price of $3.25 per Common Shares. The proceeds of the subscription receipts were utilized to fund Liberty Energy's ownership share of the cost of acquisition of the California Utility.

(f) **Calpeco Private Placement**: California Pacific Electric Company, LLC $45,000,000 5.19% Senior Unsecured Notes, Series A, due December 29, 2020 and $25,000 000 5.59% Senior

Unsecured Notes, Series B, due December 29, 2025, dated as of December 29, 2010 pursuant to which Calpeco entered into a $70 million senior unsecured private debt placement. The private placement is a senior unsecured private placement with U.S. institutional investors, backed solely by the California Utility assets. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

(g) **Red Lily Agreements**: Loan Agreement dated as of April 19, 2010 between Red Lily Wind Energy Partnership, as Borrower, and Integrated Private Debt Fund II LP and APUC, as Lenders. pursuant to which the Lenders agreed to fund the Red Lily project costs with $31 million of senior debt to be provided by Integrated Private Debt Fund II LP and with $17.5 million of senior and subordinated debt to be provided by APUC and APCo. APUC and/or certain subsidiaries also entered into agreements to provide services to and will receive fees for the development, construction, operation and supervision of the project, pursuant to a Supervisory Agreement, a Development and Construction Services Agreement, and an Operations Agreement, all dated April 19, 2010. In addition, a subsidiary of APCo, APT, entered into an Option Agreement dated April 19, 2010 among the Borrower, 7314507 Canada Inc., Red Lily Wind Energy Corp. and APT. Co has been granted an option to subscribe for a 75% equity interest in the project in exchange for its subordinated debt commitment, exercisable five years following commissioning of the project.

13. INTERESTS OF EXPERTS

KPMG LLP is the external auditor of the Corporation and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and management discussion and analysis for the year ended December 31, 2010.

SCHEDULE A

Renewable Energy - Hydroelectric and Wind Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Ontario Facilities					
Facility: Long Sault Rapids Facility (Hydroelectric) **Owner:** Algonquin Power (Long Sault) Partnership and N-R Power Partnership	18,000	Abitibi River near Cochrane, Ontario	**Electricity Purchaser:** OEFC **Rates:** $0.09195/kW-hr (average estimate)	111,600	2047
Facility: Hurdman Dam Facility (Hydroelectric) **Owner:** APFC	570	Mattawa River near Mattawa, Ontario	**Electricity Purchaser:** Hydro One Inc. **Rates:** Paid on Hourly Spot Market Price	3,150	2015
Facility: Burgess Dam Facility (Hydroelectric) **Owner:** APFC	140	Muskoka River near Bala, Ontario	**Electricity Purchaser:** OEFC **Rates:** Paid on Hourly Spot Market Price	950	2010
Facility: Campbellford Facility (Hydroelectric) **Owner:** Campbellford LP	4,000	Trent River near Campbellford, Ontario	**Electricity Purchaser:** OEFC **Rates:** $0.04346/kW-hr (average estimate)	26,250	2019

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Québec Developments					
Facility: Saint-Alban Facility (Hydroelectric) **Owner:** SLI(4)	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07609/kW-hr (Jan – Nov) $0.07837/kW-hr (Dec)	37,300	2016
Facility: Glenford Facility (Hydroelectric) **Owner:** Glenford Partnership	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07609/kW-hr (Jan – Nov) $0.07837/kW-hr (Dec)	23,750	2020
Facility: Rawdon Facility (Hydroelectric) **Owner:** APFC	2,500	Ouareau River near the Village of Rawdon, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07609/kW-hr (Jan – Nov) $0.07837/kW-hr (Dec)	15,300	2014
Facility: Côte Ste-Catherine Facility (Hydroelectric) **Owner:** Mont-Laurier Partnership	11,120	St. Lawrence River near the Town of Ste.-Catherine, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** Phase I Energy $0.04853/kW-hr Phase II Energy $0.06491/kW-hr Capacity $159.32/kilowatt * Phase III Energy $0.06759/kW-hr Capacity $167.05/kilowatt * * calculated over the average kilowatt output over the period December to March	Phase 1: 15,500 Phase II: 35,100 Phase III: 34,750	Phase 1: 2021 Phase II: 2018 Phase III: 2021

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates[(1)]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Facility: Ste-Raphaël Facility (Hydroelectric) **Owner:** APFC	3,500	Rivière de Sud near Québec City, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** \$0.07609/kW-hr (Jan – Nov) \$0.07837/kW-hr (Dec)	22,550	2014
Facility: Mont Laurier Facility (Hydroelectric) **Owner:** Mont-Laurier Partnership	2,725	Rivière-du-Lièvre in the Town of Mont Laurier, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** \$0.05803/kW-hr	21,250	2027
Facility: Rivière-du-Loup Facility (Hydroelectric) **Owner:** APFC	2,600	Rivière-du-Loup near the Town of Rivière-du-Loup, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** \$0.07609/kW-hr (Jan – Nov) \$0.07837/kW-hr (Dec)	17,250	2015
Facility: Hydraska Facility (Hydroelectric) **Owner:** APT	2,250	Yamaska River near the Town of St.-Hyacinthe, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** Summer Energy \$0.06399/kW-hr Winter Energy \$0.11734/kW-hr	9,100	2014
Facility: Ste-Brigitte Facility (Hydroelectric) **Owner:** APFC	4,200	Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** \$0.07609/kW-hr (Jan – Nov) \$0.07837/kW-hr (Dec)	12,750	2014

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Facility: Belleterre Facility (Hydroelectric) **Owner:** APFC	2,200	Winneway River in the Municipality of Laforce, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** Summer Energy: $0.06342/kW-hr Winter Energy: $0.11779/kW-hr Capacity: $156.75/kilowatt (over the average kilowatt output over the period December to March)	11,250	2013
Facility: Donnacona Facility (Hydroelectric) **Owner:** Donnacona Partnership	4,800	Jacques Cartier River near Donnacona, Québec	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07609/kW-hr (Jan – Nov) $0.07837/kW-hr (Dec)	20,550	2022
Facility: St. Raphaël de Bellechasse Facility (Arthurville) (Hydroelectric) **Owner:** APT	650	Riviere du Sud downstream from Ste-Raphaël	**Electricity Purchaser:** Hydro-Québec **Rates:** $0.07609/kW-hr (Jan – Nov) $0.07837/kW-hr (Dec)	2,900	2013
Newfoundland Facility					
Facility: Rattle Brook Facility (Hydroelectric) **Owner:** Rattlebrook Partnership	4,000	Rattle Brook near Jackson’s Arm, Newfoundland	**Electricity Purchaser:** Newfoundland and Labrador Hydro **Rates:** Summer $0.07148/kW-hr Winter $0.09693/kW-hr	15,950	2024
New York Facilities					
Facility: Ogdensburg Facility (Hydroelectric) **Owner:** Trafalgar[5]	3,675	Oswegatchie River near Ogdensburg, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04326/kW-hr (est)[6]	11,100	2011

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Facility: Forestport Facility (Hydroelectric) **Owner:** Trafalgar[5]	3,300	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04297/kW-hr (est) [6]	11,500	2011
Facility: Herkimer Facility (Hydroelectric) **Owner:** Trafalgar[5]	1,680	West Canada Creek near Herkimer, New York	**Electricity Purchaser:** National Grid **Rates:** No target rate as the site is expected to be offline	0[7]	2011
Facility: Christine Falls Facility (Hydroelectric) **Owner:** Christine Falls Corporation[5]	850	Sacandaga River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates:** US $0.04167/kW-hr (est) [6]	3,300	2028
Facility: Cranberry Lake (Hydroelectric) **Owner:** Trafalgar[5]	500	Oswegatchie River near Clifton, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04321/kW-hr (est) [6]	1,800	2011
Facility: Kayuta Lake Facility (Hydroelectric) **Owner:** Trafalgar[5]	400	Black River near Boonville, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.00824/kW-hr (est)	1,800	2028
Facility: Adams Facility (Hydroelectric) **Owner:** Trafalgar [5]	350	Sandy Creek near Adams, New York	**Electricity Purchaser:** National Grid **Rates:** No target rate as the site is expected to be offline	0[7]	2028

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Facility: Kings Falls Facility (Hydroelectric) **Owner:** Tug Hill Energy, Inc.[8]	1,750	Deer River near Copenhagen, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04352/kW-hr [6]	3,000	2011
Facility: Otter Creek Facility (Hydroelectric) **Owner:** Tug Hill Energy, Inc.[8]	530	Otter Creek in Craig, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04298/kW-hr (est) [6]	1,900	2011
Facility: Phoenix Facility (Hydroelectric) **Owner:** Oswego Hydro Partners L.P.[8]	3,500	Oswego River in Phoenix, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.09205/kW-hr Flat Rate	11,250	2026
Facility: Beaver Falls Facility (Hydroelectric) **Owner:** Algonquin Power (Beaver Falls) LLC	2,500	Beaver River in Beaver Falls, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.02989/kW-hr (est)	15,400	2019
Facility: Burt Dam Facility (Hydroelectric) **Owner:** Burt Dam Partnership	600	18 Mile Creek near Newfane, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04354/kW-hr (est) [6]	1,950	2011
Facility: Hollow Dam Facility (Hydroelectric) **Owner:** Hollow Dam Partnership	900	Oswegatchie River near Gouverneur, New York	**Electricity Purchaser:** National Grid **Rates:** US$0.04328/kW-hr (est) [6]	4,050	2011

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
New England Facilities					
Facility: Greggs Falls Facility (Hydroelectric) **Owner:** Greggs Falls Partnership	3,500	Piscataquog River near the Town of Goffstown, New Hampshire	**Electricity Purchaser:** Public Service Company of New Hampshire ("**PSNH**") **Rates:** US$0.05058/kW-hr (est) [8]	10,450	60 day written notice
Facility: Pembroke Facility (Hydroelectric) **Owner:** Pembroke Hydro Associates Limited Partnership[10]	2,600	Suncook River near the Town of Pembroke, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.05159/kW-hr (est) [8]	9,750	60 day written notice
Facility: Clement Facility (Hydroelectric) **Owner:** Clement Dam Hydroelectric LLC [11]	2,400	Winnipisaukee River near the Town of Tilton, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.05242/kW-hr (est) [8]	10,700	60 day written notice
Facility: Franklin Facility (Hydroelectric) **Owner:** Franklin Power LLC [8]	River Bend 1,600 Steven's Mill 200	Winnipesaukee River near the Town of Franklin, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** River Bend US$0.04803/kW-hr (est) [8] Steven's Mill US$0.05292/kW-hr (est) [8]	River Bend 6,800 Steven's Mill 950	60 day written notice – both sites
Facility: Lochmere Facility (Hydroelectric) **Owner:** HDI Partnership	1,200	Winnipesaukee River near Lochmere, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.05179/kW-hr (est) [8]	4,150	60 day written notice

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Facility: Lakeport Facility (Hydroelectric) **Owner:** Lakeport Corporation	600	Winnipesaukee River near Laconia, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US$0.05185/kW-hr (est) [8]	2,450	60 day written notice
Facility: Milton Facility (Hydroelectric) **Owner:** SFR Hydro Corporation	1,335	Salmon River near the Town of Milton, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** No target rate as the site is expected to be offline	0[7]	60 day written notice
Facility: Mine Falls Facility (Hydroelectric) **Owner:** Mine Falls Limited Partnership	3,000	Nashua River near the City of Nashua, New Hampshire	**Electricity Purchaser:** PSNH **Rates:** US $0.05139/kW-hr (est)[8]	11,400	60 day written notice
Facility: Great Falls Facility (Hydroelectric) **Owner:** Great Falls Partnership	10,950	Passaic River near the City of Paterson, New Jersey	**Electricity Purchaser:** Public Service Electric and Gas Company **Rates:** US $0.05491/kW-hr (est)[8]	23,350	60 day written notice
Facility: Moretown Facility (Hydroelectric) **Owner:** Moretown Partnership	1,200	Mad River near Moretown, Vermont	**Electricity Purchaser:** Vermont Power Exchange, Inc. **Rates:** $0.10702/kW-hr (average estimate)	2,100	2018

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Western Canada Facility					
Facility: Dickson Dam Facility (Hydroelectric) **Owner:** APOT	15,000	Innisfail, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation **Rates:** Energy: $0.0619/kW-hr	65,900	2012
Maritime Facilities					
Facility: Tinker Facility (Hydroelectric) **Owner:** APT	33,500	Perth-Andover, New Brunswick	**Electricity Purchaser:** Maine Gen Co. Town of Perth-Andover **Rates:** Maine Gen Co.: US $0.071/kWhr (net of transmission charges – variable monthly) Town of Perth Andover: $.065/kWhr CDN (net of transmission charges – variable monthly)	124,000	2011
Facility: Caribou Facility (Hydroelectric) **Owner:** Maine Gen Co.	900	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Energy - US $0.050/kWhr	5,050	2011
Facility: Squa Pan Facility (Hydroelectric) **Owner:** Maine Gen Co.	1,400	Squa Pan Lake, near Caribou Maine	**Electricity Purchaser:** AES **Rates:** Energy - US $0.050/kWhr Reserve Market: variable monthly US $0.3/kW-hr (average estimate)	700	2011

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement
Wind Facilities					
Facility: St. Leon Facility (Wind) **Owner:** St. Leon LP	99,000	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro **Rates:** Dependable $0.05831/kW-hr (average estimate) Non-dependable $0.04658/kW-hr (average estimate) Rates indexed annually to CPI in May. WPPI $ 0.0100/kW-hr	372,000	2025 + one 5 year extension
Facility: Red Lily (Wind) **Owner:**	26,400	Saskatchewan	**Electricity Purchaser:** SaskPower **Rates:**	88,000	2036
Facility: Amherst Island (Wind)	75,000	Stella, Ontario	**n/a** (Under Development)	247,000	n/a
Facility: Saint-Damase (Wind)	25,000	Saint-Damase, Québec	**n/a** (Under Development)	86,000	n/a
Facility: Val-Éo (Wind)	25,000	Saint-Gédéon, Québec	**n/a** (Under Development)	66,000	n/a
Facility: Morse (Wind)	20,000	Morse, Saskatchewan	**n/a** (Under Development)	75,000	n/a

Notes:

(1) 2011 PPA rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable PPAs. Long-term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project.

(2) No agreement has been obtained for a long-term lease; the current lease is on a month-to-month basis.

(4) See "*Description of the Business - Production Method, Principal Markets, Distribution Methods and Material Facilities – Hydroelectric – Material Facilities – Saint-Alban Facility*"

(5) APC provides Trafalgar with certain operational services in respect of the Trafalgar Facilities.

(6) These rates reflect the estimated Avoided Costs of National Grid.

(7) Scheduled to be offline for repairs in 2011. No decision has been made as to the timing of repairing these Facilities.

(8) PSNH purchases the energy produced by these generating stations at the ISO-NE. market rates. These agreements are cancellable on 60 days written notice.

SCHEDULE B

Thermal - Biomass, Cogeneration, Steam, Diesel and Energy From Waste Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Thermal - Biomass Facility						
Facility: Valley Power Facility (Biomass) **Owner:** Valley Power L.P.	12,000	Drayton Valley, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation **Rates:** Energy: $0.0709/kW-hr	74,000[3]	2014	Owned
Thermal - Cogeneration Facilities						
Facility: Sanger Facility (Cogeneration) **Owner:** Sanger LLC[1]	56,000	Sanger, California	**Electricity Purchaser:** PG&E **Rates:** Period A PG&E Avoided Cost - US0.046/ kW-hr (estimated average)* Period B US$ 0. 047/ kW-hr (estimated average)* * subject to gas price indexing **Capacity -** US$ 190 per kW/year up to 38,000 kW-hrs + bonus of 18% (80% earned May – Oct)	133,000	2021	Owned
Facility: Windsor Locks Facility (Cogeneration) **Owner:** Algonquin Windsor Locks LLC[1]	56,000	Windsor Locks, Connecticut	**Electricity Purchaser:** ISO New England **Rates:** Market Rates , included hourly energy, forward capacity and forward reserve payments Mill/NGC - US$0. 053/kW-hr* Capacity $197,000** Steam - DNM/NGC - US$7.90/1000lbs* Capacity $125,000 * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are CPI indexed. Capacity Market and Spot Market – market prices	182,000	Merchant	2018
Facility: Brampton Cogeneration Inc. (Cogeneration) **Owner:** APOT	N/A	Brampton, Ontario	**Electricity Purchaser:** N/A **Rates:** Steam - Normapac $7.47/1000lbs* Capacity $102,700** * Estimated average rate, includes variable component based on natural	675 million lbs of steam	2024	N/A

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
			gas prices. **Estimated average monthly rate, charges are partially CPI indexed.			
Facility: EFW Facility (Energy from Waste) **Owner:** Algonquin Power Energy from Waste Inc.	10,100	Brampton, Ontario	**Electricity Purchaser:** OEFC **Rates:** $0.055/kW-hr (average estimated summer rate) $0.0641/kW-hr (average estimated winter rate) Tipping - Peel – $91/tonne up to 127,900 tonnes, $66 tonnes thereafter Waste rates subject to monthly CPI indexing	7,500	2012	Owned
Thermal - Diesel						
Facility: Tinker Facility (Diesel) **Owner:** Tinker Gen Co.	1,000	Perth-Andover, New Brunswick	**Electricity Purchaser:** AES **Rates:** Capacity – US $2.875/kw -mo	0(2)	2011	Owned
Facility: Caribou Facility (Diesel) **Owner:** Maine Gen Co.	7,000	Caribou, Maine	**Electricity Purchaser:** Not under contract. **Rates:** – N/A	0(2)	2011	Owned
Facility: Flo’s Inn Facility (Diesel) **Owner:** Maine Gen Co.	4,000	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Capacity – US $2.875/kw -mo	0(2)	2011	Owned

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2011 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Steam						
Facility: Caribou Facility (Steam) **Owner:** Maine Gen Co.	21,700	Caribou, Maine	**Electricity Purchaser:** Not Under Contract **Rates:** N/A	0[2]	2011	Owned

Notes:

(1) This entity is a subsidiary of APFA.

(2) Available to provide capacity only. The thermal facilities located in Northern Maine and New Brunswick are not considered strategic to APUC. As a result APUC is taking steps to shutdown these facilities.

(3) This facility no longer fits APUC's preferred asset profile and is no longer considered strategic to APUC. As a result, APUC's interest in these facilities is expected to be sold in 2011.

SCHEDULE C

Wastewater and Water Distribution Facilities

Utility	Owner[1]	Location	Type of Utility	December 31, 2010 Connections	Rates
Black Mountain	Black Mountain Sewer Corporation	Carefree, Arizona	Wastewater	2,173	Residential US $65.24 (standard monthly rate)
Gold Canyon	Gold Canyon Sewer Company	Gold Canyon Arizona	Wastewater	7,315	Residential US $52.40 (standard monthly rate)
Bella Vista	Bella Vista Water Co., Inc.	Sierra Vista, Arizona	Water Distribution	8,998	Residential US $26.75 (Average monthly rate)
Tall Timbers	Tall Timbers Utility Company, Inc.	Tyler, Texas	Wastewater	1,920	Residential US $54.93 (standard monthly rate)
Woodmark	Woodmark Utilities, Inc.	Tyler, Texas	Wastewater	1,699	Residential US $47.76 (standard monthly rate)
Litchfield Park	Litchfield Park Service Company	Litchfield, Park, Arizona	Wastewater	18,536	Residential US $38.99 [3]
			Water Distribution	16,533	Commercial US $65.93 [3] US $39.77 [3] (Average residential rate)
Fox River	AWRI	Sheridan, Illinois	Wastewater	219	US $240.08 US $141.61
			Water Distribution	220	
Timber Creek	AWRM	DeSoto, Missouri	Wastewater	22	US $16.00 min & $17.24/1000 gal.
			Water Distribution	31	US $8.96 min. & US $5.96/1000 gal
Holliday Hills	AWRM	Branson, Missouri	Water Distribution	481	US $8.96 min. & US $5.96/1000 gal
Ozark Mountain	AWRM	Kimberling City, Missouri	Wastewater	241	US $16.00 min & $17.24/1000 gal.
			Water Distribution	255	US $8.96 min. & $5.96/1000 gal
Holly Lake Ranch	AWRT	Hawkins, Texas	Wastewater	131	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	1,898	US $39.81 min. & $1.30/1000 gal

Utility	Owner[1]	Location	Type of Utility	December 31, 2010 Connections	Rates
Big Eddy	AWRT	Flint, Texas	Wastewater	411	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	663	US $39.81 min. & $1.30/1000 gal
Piney Shores	AWRT	Conroe, Texas	Wastewater	269	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	273	US $39.81 min. & $1.30/1000 gal
Hill Country	AWRT	New Braunfels, Texas	Wastewater	378	US $128.53 min & US $3.65/1000 gal.
			Water Distribution	225	US $39.81 min. & $1.30/1000 gal
Rio Rico	Rio Rico Utilities Inc.	Rio Rico, Arizona	Wastewater	2,201	US $56.36 (residential rates)
			Water Distribution	6,730	US $6.45 min. & 0-4,000 gal – US $1.44/1,000 gal 4,001-10,000 gal – US $1.70/1,000 gal >10,000 gal – US $1.90/1,000 gal
Northern Sunrise	Northern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	355	US $31.00 min & 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal >10,000 gal – US $3.90/1,000 gal
Southern Sunrise	Southern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	860	US $31.00 min & 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal >10,000 gal – US $3.90/1,000 gal
Entrada Del Oro [2]	Entrada Del Oro Sewer Company	Gold Canyon, Arizona	Wastewater	302	US $76.00 (standard monthly rate)
Seaside Resort	AWRT	Galveston, Texas	Water Distribution	156	US $166.68
			Wastewater Collection	156	US $165.45
Total connections				**73,651**	

Notes:

(1) Each of these entities is a wholly-owned subsidiary of Liberty Water Co.

(2) Liberty Water Co. currently holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition.

(3) Effective rates based on upon implementation of rates awarded on December 1, 2010 at the Litchfield Facility.

SCHEDULE D

Wastewater and Water Distribution Facilities

Utility	Owner(1)	Location	Type of Utility	December 31, 2010 Connections	Rates
Calpeco	California Pacific Electric Company, LLC	Lake Tahoe, California	Electricity Distribution	48,000	Residential Rates – Monthly Charge $6.62. plus $$0.10864/kwh for baseline usage; $0.13696 for excess usage

SCHEDULE E

ALGONQUIN POWER & UTILITIES CORP.

MANDATE OF THE AUDIT COMMITTEE

By appropriate resolution of the board of directors (the "**Board**") of Algonquin Power & Utilities Corp., the Audit Committee (the "**Committee**") has been established as a standing committee of the Board with the terms of reference set forth below. Unless the context requires otherwise, the term "Corporation" refers to Algonquin Power & Utilities Corp. and its subsidiaries.

1. PURPOSE

1.1 The Committee's purpose is to:

(a) assist the Board's oversight of:

(i) the integrity of the Corporation's financial statements, Management's Discussion and Analysis ("**MD&A**") and other financial reporting;

(ii) the Corporation's compliance with legal and regulatory requirements;

(iii) the external auditor's qualifications, independence and performance;

(iv) the performance of the Corporation's internal audit function and internal auditor;

(v) the communication among management of the Corporation and its subsidiary entities and the Corporation's Chief Executive Officer and its Chief Financial Officer (collectively, "**Management**"), the external auditor, the internal auditor and the Board;

(vi) the review and approval of any related party transactions; and

(vii) any other matters as defined by the Board;

(b) prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

2. COMMITTEE MEMBERSHIP

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

(a) be a director of the Corporation;

(b) not be an officer or employee of the Corporation or any of the Corporation's subsidiary entities or affiliates;

(c) be an unrelated director for the purposes of the Toronto Stock Exchange (the "**TSX**") Corporate Governance Policy; and

(d) satisfy the independence requirements applicable to members of audit committees under each of the rules of National Instrument 52 110 – Audit Committees of the Canadian Securities Administrators (“**NI 52 110**”) and other applicable laws and regulations.

2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under the TSX Corporate Governance Policy, NI 52 110 and other applicable laws and regulations.

2.4 Annual Appointment of Members – The Committee and its Chair shall be appointed annually by the Board and each member of the Committee shall serve at the pleasure of the Board until he or she resigns, is removed or ceases to be a director.

3. COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly, a majority of the members of the Committee shall constitute a quorum and the Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings – As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Board approve, the annual audited financial statements of the Corporation or at which the Committee reviews the interim financial statements of the Corporation, and at such other times as the Committee deems appropriate, the Committee shall meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

(a) representatives of Management;

(b) the external auditor; and

(c) the internal audit personnel.

3.3 Attendance at Meetings – The external auditors are entitled to attend and be heard at each Committee meeting. In addition, the Committee may invite to a meeting any officers or employees of the Corporation, legal counsel, advisor and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities.

4. COMMITTEE AUTHORITY AND RESOURCES

4.1 Direct Channels of Communication – The Committee shall have direct channels of communication with the Corporation’s internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Corporation such independent legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.

4.3 Funding – The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this Charter.

4.4 Investigations – The Committee shall have unrestricted access to the personnel and documents of the Corporation and the Corporation's subsidiary entities and shall be provided with the resources necessary to carry out its responsibilities.

5. REMUNERATION OF COMMITTEE MEMBERS

5.1 Director Fees Only – No member of the Committee may accept, directly or indirectly, fees from the Corporation or any of its subsidiary entities other than remuneration for acting as a director or member of the Committee or any other committee of the Board.

5.2 Other Payments – For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Corporation. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any of its subsidiaries, other than limited partners, non–managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

6. DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

6.1 Overview – The Committee's principal responsibility is one of oversight. Management is responsible for preparing the Corporation's financial statements and the external auditor is responsible for auditing those financial statements.

6.2 The Committee's specific duties and responsibilities are as follows:

(a) Financial and Related Information

(i) Annual Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's annual financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(ii) Interim Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's interim financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(iii) Prospectuses and Other Documents – The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Board as a whole.

(iv) Accounting Treatment – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Corporation's accounting principles and financial statement presentation, including, without limitation, the following:

(A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of Management's disclosures along with any significant proposed modifications by the auditors that were not included;

(B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management's judgments and accounting estimates and the external auditor's judgments about the quality of the Corporation's accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor's preferred accounting treatment or accounting policy is not selected, the reasons therefor should also be reported to the Committee;

(C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

(E) any significant changes in the Corporation's selection or application of accounting principles;

(F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and

(G) the adequacy of the Corporation's internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information – The Committee shall:

(A) review, and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Corporation containing audited, unaudited or forward-looking financial information in advance of its public release by the Corporation, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

(B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

(C) satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the Corporation's financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

(b) External Auditor

(i) Authority with Respect to External Auditor – As representative of the Corporation's shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation's shareholders for appointment as external auditor, whether at any time the incumbent external auditor should be removed from office, and the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan – The Committee shall approve, prior to the external auditor's audit, the external auditor's audit plan (including, without limitation, staffing), the scope of the external auditor's review and all related fees.

(iii) Independence – The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

(A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Corporation and the Committee shall actively engage in a dialogue with the external auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Board take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor's independence.

(B) In accordance with applicable laws and regulations, the Committee shall pre–approve any non–audit services (including, without limitation, fees therefor) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non–audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non audit services. The Chair may approve additional non audit services that arise between Committee meetings, provided that the Chair reports any such approvals to the Committee at the next scheduled meeting.

(C) The Committee shall establish a policy setting out the restrictions on the Corporation's subsidiary entities hiring partners, employees, former partners and former employees of the Corporation's external auditor or former external auditor.

(iv) Rotating of Auditor Partner – The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit – The Committee shall review with the external auditor:

(A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Corporation's response to that letter;

(B) any changes required in the planned scope of the internal audit; and

(C) the internal audit department's responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Corporation's auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by Section 5741 of the CICA Handbook – Assurance relating to the conduct of the audit.

(c) Internal Audit Function – Controls

(i) Regular Reporting – Internal audit personnel shall report regularly to the Committee.

(ii) Oversight of Internal Controls – The Committee shall oversee Management's design and implementation of and reporting on the Corporation's internal controls and review the adequacy and effectiveness of Management's financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems devisable in respect of the internal audit function.

(iii) Review of Audit Problems – The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management's responses thereto.

(iv) Review of Internal Audit Personnel – The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(d) Risk Assessment and Risk Management

(i) Risk Exposure – The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Corporation's major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) Investment Practices – The Committee shall review Management's plans and strategies around investment practices, banking performance and treasury risk management.

(iii) Compliance with Covenants – The Committee shall review Management's procedures to ensure compliance by the Corporation with its loan covenants and restrictions, if any.

(e) Legal Compliance

(i) On at least a quarterly basis, the Committee shall review with the Corporation's legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Corporation's financial position, operating results or financial statements and the Corporation's compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Board with respect to the Corporation's policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Board, promptly after becoming aware of any material non–compliance by the Corporation with applicable laws and regulations.

(f) Whistle Blowing – The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation's subsidiary entities of concerns regarding questionable accounting or auditing matters.

(g) Related Party Transactions – The Committee shall review and approve any transaction between the Corporation and a related party and any transaction involving the Corporation and another party in which the parties' relationship could enable the negotiation of terms on other than an independent, arms' length basis.

(h) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

(i) Liaison – The Committee shall review and ensure that appropriate liaison and co–operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

(j) Public Reports – The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

(k) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

7. REPORTING TO THE BOARD

7.1 Regular Reporting – If applicable, the Committee shall report to the Board following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

8. EVALUATION OF COMMITTEE PERFORMANCE

8.1 Performance Review – The Committee shall periodically assess its performance.

8.2 Amendments to Charter

(a) Review by Committee – On at least an annual basis, the Committee shall review and discuss the adequacy of this Charter and if applicable, recommend any proposed changes to the Board.

(b) Review by Board – The Board will review and reassess the adequacy of the Charter on an annual basis and at such other times, as it considers appropriate.

9. LEGISLATIVE AND REGULATORY CHANGES

9.1 Compliance – It is the Board' intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this Charter shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least annually to reflect such amendments.

10. CURRENCY OF CHARTER

10.1 Currency of Charter – This Charter was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 31, 2010.

SCHEDULE F

Caution concerning forward-looking statements

Certain statements included in this AIF contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. Forward-looking information is included throughout this Annual Information Form, including among other places, under the heading “General Development of the Business”, “Description of the Business” and “Legal Proceedings”. These statements and information are forward-looking, and are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments, and other factors believed to be appropriate in the circumstances.

Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include those set out in this AIF under “Risk Factors. Readers are cautioned that such risks and uncertainties may cause APUC’s actual results to vary materially from those expressed in, or implied by, the forward-looking statements and information. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

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Section 3: EX-99.2 (AUDITED ANNUAL FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2010)

Exhibit 99.2

Consolidated Financial Statements of

Algonquin Power & Utilities Corp.

For the year ended December 31, 2010 and December 31, 2009

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles and reconciled to US GAAP. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2010.

KPMG LLP, independent auditors appointed by the shareholders of the Company, has audited the consolidated financial statements of the Company for the year ended December 31, 2010, has also issued a report on the effectiveness of the Company's internal control over financial reporting.

Date: March 31, 2011

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

KPMG LLP
Chartered Accountants
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated balance sheets of Algonquin Power & Utilities Corp and subsidiaries as at December 31, 2010 and 2009, and the related consolidated statements of operations, deficit, comprehensive income (loss) and accumulated other comprehensive income (loss), and cash flows for each of the years in the two-year period ended December 31, 2010. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2010 and 2009 and the results of their operations and its cash flows for each of the years in the two-year period ended December 31, 2010 in conformity with Canadian generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 31, 2011 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 31, 2011

KPMG LLP
Chartered Accountants
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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, the consolidated statements of operations, deficit, comprehensive income (loss) and accumulated other comprehensive income (loss), and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2010 and 2009 and the consolidated results of its operations and its consolidated cash flows for the two years then ended in accordance with Canadian generally accepted accounting principles.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 3, 2011

Algonquin Power & Utilities Corp
Consolidated Balance Sheets
(thousands of Canadian dollars)

	2010	2009
ASSETS		
Current assets:		
Cash	$ 5,146	$ 2,796
Short term investments (note 1(d))	3,674	40,010
Accounts receivable	27,082	20,484
Prepaid expenses	3,520	4,674
Income tax receivable	—	1,143
Current portion of future tax asset (note 13)	14,015	14,566
Current portion of notes receivable (note 5)	1,172	414
	54,609	84,087
Long-term investments and notes receivable (note 5)	35,902	23,470
Future non-current income tax asset (note 13)	74,006	61,219
Property, plant and equipment (note 6)	729,076	749,350
Intangible assets (note 7)	73,886	85,929
Restricted cash (note 1(e))	3,563	4,316
Deferred financing costs	258	200
Other assets (note 8)	9,617	4,842
	$ 980,917	$ 1,013,413
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 33,506	$ 33,219
Dividends payable	5,721	1,857
Current portion of long-term liabilities (note 9)	70,490	3,360
Current portion of other long-term liabilities (note 11)	1,011	1,025
Current portion of derivative instruments (note 22)	2,338	5,775
Current income tax liability	200	5
Current portion of deferred credit (note 13)	11,020	10,500
Future income tax liability (note 13)	514	913
	124,800	56,654
Long-term liabilities (note 9)	188,641	241,412
Convertible debentures (note 10)	170,975	173,257
Other long-term liabilities (note 11)	30,872	25,228
Future non-current income tax liability (note 13)	80,953	79,914
Derivative instruments (note 22)	3,525	3,920
Deferred credit (note 13)	32,222	39,379
Shareholders' equity:		
Shareholders' capital (notes 3 and 12)	796,576	787,037
Deficit	(347,802)	(344,676)
Accumulated other comprehensive loss	(99,845)	(48,712)
	348,929	393,649
Commitments and contigencies (note 15)		
Subsequent events (notes 4(a) and 9)		
	$ 980,917	$ 1,013,413

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp
Consolidated Statements of Operations
(thousands of Canadian dollars, except per unit amounts)

	2010	2009
Revenue:		
Energy sales	$ 132,726	$ 130,436
Waste disposal fees	9,039	14,468
Water reclamation and distribution	37,786	38,513
Other revenue (note 20)	3,331	3,848
	182,882	187,265
Expenses		
Operating	97,851	102,736
Amortization of property, plant and equipment	36,429	38,578
Amortization of intangible assets	10,144	7,305
Management costs (note 14)	—	850
Administrative expenses	14,886	10,712
Gain on foreign exchange	(528)	(1,261)
	158,782	158,920
Earnings before undernoted	24,100	28,345
Interest expense	25,612	21,387
Interest, dividend and other income (note 19)	(4,962)	(6,401)
Impairment loss of property, plant and equipment (note 6)	2,492	5,354
Write down of note receivable (note 5)	—	1,103
(Gain) / loss on derivative financial instruments (note 22)	1,103	(17,318)
	24,245	4,125
Earnings/(loss) from operations before income taxes, non-controlling interest and corporatization costs	(145)	24,220
Management internalization costs (note 14)	—	4,693
Other corporatization costs (note 3)	—	3,460
Earnings/(loss) before income taxes and non-controlling interest	(145)	16,067
Income tax expense (recovery) (note 13)		
Current	(69)	397
Future	(20,159)	(18,324)
	(20,228)	(17,927)
Non-controlling interest in earnings of subsidaries	444	2,737
Net earnings	$ 19,639	$ 31,257
Basic net earnings per share (note 18)	$ 0.21	$ 0.39
Diluted net earnings per share (note 18)	$ 0.21	$ 0.39

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp
Consolidated Statements of Cash Flows
(thousands of Canadian dollars)

	2010	2009
Cash provided by (used in):		
Operating Activities:		
Net earnings	$ 19,639	$ 31,257
Items not affecting cash:		
Amortization of property, plant and equipment	36,429	38,578
Amortization of intangible assets	10,144	7,305
Other amortization	2,911	1,441
Future income taxes / (recovery)	(20,159)	(18,324)
Gain on sale of land	—	(1,451)
Stock option expense	108	—
Write down of property, plant and equipment	2,492	5,354
Write down of note receivable	—	1,103
Expense on convertible debenture conversion	—	1,252
Management internalization costs	—	4,693
Unrealized gain on derivative financial instruments	(7,142)	(23,106)
Minority interest	444	2,737
Unrealized foreign exchange gain	(414)	(1,503)
	44,452	49,336
Changes in non-cash operating working capital (note 17)	728	(1,305)
	45,180	48,031
Financing Activities:		
Cash distributions / dividends (note 16)	(18,901)	(19,043)
Cash distributions to non-controlling interest (notes 14 and 16)	(444)	(809)
Common share issue, net of costs	—	21,180
Convertible debenture issue, net of costs	—	57,975
Repayment Trustee loans	—	218
Deferred financing costs	(1,194)	(109)
Increase in long-term liabilities	98,787	23,000
Decrease in long-term liabilities	(80,078)	(69,175)
Increase / (decrease) in other long-term liabilities	4,456	(5,870)
	2,626	7,367
Investing Activities:		
Decrease in restricted cash	575	343
Decrease / (increase) in short-term investments	36,212	(39,995)
Increase in other assets	(2,723)	(1,597)
Distributions received in excess of equity income	1,140	1,991
Receipt of principal on notes receivable	410	448
Proceeds from liquidation of Highground assets (note 4(f))	170	983
Proceeds from sale of land	—	2,502
Acquisition of long-term investments (notes 4(e) and 5)	(14,759)	(87)
Net additions to property, plant and equipment	(20,831)	(10,916)
The unit exchange transaction (note 3)	—	(10,813)
Acquisitions of operating entities	(45,524)	(1,177)
	(45,330)	(58,318)
Effect of exchange rate differences on cash	(126)	(186)
Increase / (decrease) in cash	2,350	(3,106)
Cash, beginning of the year	2,796	5,902
Cash, end of the year	$ 5,146	$ 2,796
	—	—
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 21,562	$ 19,956
Cash paid / (received) during the period for income taxes	$ (285)	$ 873

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp
Consolidated Statements of Deficit
(thousands of Canadian dollars)

	2010	2009
Balance, beginning of year	$ (344,676)	$ (356,621)
Net earnings	19,639	31,257
Distributions / dividends	(22,765)	(19,312)
Balance, end of year	$ (347,802)	$ (344,676)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp
Consolidated Statements of Comprehensive Income / (Loss) and
Accumulated Other Comprehensive Income / (Loss)
(thousands of Canadian dollars)

	2010	2009
Net earnings	$ 19,639	$ 31,257
Other comprehensive income /(loss):		
Forward exchange contracts settled in the year	—	(1,789)
Translation of self sustaining foreign operations due to accounting change (note 1(n))	(37,605)	—
Translation of self sustaining foreign operations (note 1(n))	(13,528)	(25,481)
Other comprehensive income / (loss)	(51,133)	(27,270)
Total comprehensive income / (loss)	$(31,494)	$ 3,987
Accumulated other comprehensive loss:		
Balance, beginning of the year	$(48,712)	$(21,442)
Translation of self sustaining foreign operations due to accounting change (note 1(n))	(37,605)	—
Other comprehensive income / (loss)	(13,528)	(27,270)
Balance, end of the year	$(99,845)	$(48,712)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water and energy utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements.

On October 27, 2009, Algonquin Power Income Fund (the "Fund") completed a reverse take-over transaction (the "Transaction") of Hydrogenics Corporation ("Hydrogenics") which resulted in the Fund's unitholders becoming shareholders in Hydrogenics which was immediately renamed Algonquin Power & Utilities Corp. As a result, the Fund itself became a wholly owned subsidiary of APUC. The transaction did not result in any change to the underlying business operations of the Fund. For accounting purposes APUC is considered a continuation of the Fund, and as such, these consolidated financial statements follow the continuity of interest method of accounting. The Transaction and its accounting treatment are more fully described in note 3.

Up to December 21, 2009, the Fund was managed by Algonquin Power Management Inc. ("APMI") (see note 14).

On March 4, 2010 the Trustees approved a resolution changing the name of the Fund from Algonquin Power Income Fund to Algonquin Power Co. ("APCo")

APUC's power generation business unit conducts business under the name APCo. APCo owns or has interests in 45 renewable energy facilities and 12 thermal energy facilities representing more than 450 MW of installed electrical generation capacity. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co ("Liberty Utilities"). Liberty Water, a wholly owned subsidiary of Liberty Utilities, owns 19 utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois. The regulated utility operating companies are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The utilities use a historic test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

1. Significant accounting policies:

(a) Basis of consolidation:

The accompanying audited consolidated financial statements of APUC have been prepared according to Canadian generally accepted accounting principles ("GAAP"), applied on a consistent basis, and includes the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIE") where the Company is the primary beneficiary. Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE, as the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company.

Intercompany transactions and balances have been eliminated.

(b) Accounting for rate regulated operations:

Effective October 1, 2009, APUC retrospectively adopted rate regulated accounting for Canadian GAAP reporting in its Liberty Water utilities following the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under Canadian GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Items to which regulatory accounting requirements apply include deferred rate case costs, and capitalization of allowance for equity funds used during construction of regulated capital projects.

Deferred rate case costs relate to costs incurred by APUC's utilities to file, prosecute and defend rate case applications and which the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator while they are expensed under Canadian GAAP for non-regulated entities.

Under ASC 980, allowance for funds used during construction projects included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. It represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction). Prior to the adoption of ASC 980, APUC capitalized interest costs directly attributable to the construction of these assets but did not capitalize the allowance for equity funds used during construction projects.

(c) Cash:

Cash consists of cash deposited at banks.

1. Significant accounting policies: (continued)

(d) Short term investments:

Short term investments, consist of money market instruments with maturities in January 2011 and are recorded at cost, which approximates current market value. Included in short term investments is an investment of $3,694 (2009 - $10,000) which is denominated in US dollars.

(e) Restricted cash:

Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(f) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. Amounts collected on trade accounts receivable are included in net cash provided by operating activities in the Consolidated Statements of Cash Flows. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the current receivables aging and current payment patterns. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(g) Property, plant and equipment:

Property, plant and equipment, consisting of land, facilities and equipment, are recorded at cost. The costs of acquiring or constructing facilities together with the related interest costs during the period of construction are capitalized. Interest costs capitalized for Liberty Water's utilities also include the allowance for equity funds used during construction.

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

The facilities and equipment, which include the cost of major overhauls, are amortized on a straight-line basis over their estimated useful lives. For facilities these periods range from 15 to 40 years. Facility equipment and overhaul costs are amortized over 2 to 10 years.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Water's utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment would be charged to net earnings as incurred.

1. Significant accounting policies: (continued)

(h) Intangible assets:

Power sales contracts and energy sales contracts acquired are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition for power sales contracts and 12 months for energy sales contracts.

Customer relationships are amortized on a straight-line basis over 40 years.

(i) Deferred costs:

Deferred costs consist of costs of arranging APCo's credit facility.

(j) Impairment of long-lived assets:

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. Recoverability is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

(k) Long-term investments and notes receivable:

Investments in which APUC has significant influence but not control or joint control are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the Consolidated Statement of Operations. All other equity investments where APUC does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and are adjusted only for other-than-temporary declines in value and additional investments.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are recorded at face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity. The interest income on notes receivable is included in net cash provided by operating activities in the Consolidated Statements of Cash Flows.

The allowance for doubtful accounts is the Company's best estimate of the amount of credit losses in the Company's existing notes. The allowance is determined on an individual note basis if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate. The Company does not accrue interest when a note is considered impaired. When ultimate collectability of the principal balance of the impaired note is in doubt, all cash receipts on impaired notes are applied to reduce the principal amount of such notes until the principal has been recovered and are recognized as interest income thereafter. Impairment losses are charged against the allowance and increases in the allowance are charged to bad debt expense. Notes are written off against the allowance when all possible means of collection have been exhausted and the potential for recovery is considered remote.

1. Significant accounting policies: (continued)

(l) Other long-term liabilities:

Other long-term liabilities include advances in aid of construction. Certain of APUC's water and wastewater utilities are provided with advances through contributions from customers, real estate developers and builders for water and sewage main extensions in order to extend water and sewer service to their properties. The amounts advanced are generally repayable over a prescribed period based on revenues generated by the housing or development in the area being developed as new customers are connected to and take service from the utilities. Generally, advances not refunded within the prescribed period are not required to be repaid. The estimated portion of the advance that will not be refunded amounts to $33,848 and is credited to property, plant and equipment as a contribution in aid of construction. APUC also receives contributions in aid of construction with no repayment requirements in which case the full amount is immediately treated as a capital grant and netted against property, plant and equipment. The estimated amount of contributions that are expected to be ultimately refunded is recorded as Advances in Aid of Construction in other long-term liabilities.

Other long-term liabilities also include deferred water rights. Deferred water rights result from a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Water's utilities' obligation by its respective state regulator to collect a deposit from each customer of its facilities when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

(m) Recognition of revenue:

Revenue derived from energy sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Water reclamation and distribution revenues are recorded when processed or delivered to customers.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts are recognized based on actual tonnage at the expected price for the contract year.

Interest from long-term investments is recorded as earned.

1. Significant accounting policies: (continued)

(n) Foreign currency translation:

APUC's policy for translation of foreign operations depends on whether the foreign operations are considered integrated or self-sustaining. In 2009, APUC's foreign operations, other than Liberty Water, were considered integrated and translated into Canadian dollars using the temporal method whereby current rates of exchange are used for monetary assets and liabilities, historical rates of exchange for non-monetary assets and liabilities and average rates of exchange for revenues and expenses, except amortization which was translated at the rates of exchange applicable to the related assets. Gains and losses resulting from these translation adjustments were included in income.

As a result of the change relating to conversion of the Company from an income trust to a corporate structure at the end of 2009, the Company re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the US divisions operate. The Company concluded that the US operations of the Renewable Energy and Thermal Energy divisions no longer should be classified as integrated foreign operations but rather as self-sustaining operations. Consequently, these divisions have been prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37,605 resulting from the current rate translation of non-monetary items, principally property, plant and equipment and intangible assets, as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

Liberty Water's utilities are considered self-sustaining foreign operations since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. These self-sustaining operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income in the Consolidated Statement of Comprehensive Income.

(o) Asset retirement obligations:

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations. Actual expenditures incurred are charged against the accumulated obligation. Based on APUC's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations have been recorded in 2010 and 2009.

1. Significant accounting policies: (continued)

(p) Income taxes:

Income taxes are accounted for using the asset and liability method. Future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the year that includes the date of enactment or substantive enactment.

The structure of APUC and its subsidiaries are complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there are can be tax matters that have uncertain tax positions. The Company recognizes income tax benefits of uncertain tax filing positions when it is more likely than not that the ultimate determination of the tax treatment of the position will result in that benefit being realized. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

A valuation allowance is recorded against future tax assets to the extent that it is considered more likely than not that the future tax asset will not be realized.

(q) Financial instruments and derivatives:

APUC has classified its cash, short term investments, accounts receivable, restricted cash, accounts payable and accrued liabilities and dividends payable as held-for-trading, which are measured at fair value. Notes receivable are classified as loans and receivables, which are measured at amortized cost as there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are classified as other financial liabilities, which are measured at amortized cost, using the effective interest method.

Transaction costs that are directly attributable to the acquisition or issuance of financial assets or liabilities are accounted for as part of the respective asset or liability's carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Costs considered as commitment fees paid to financial institutions are recorded in deferred costs, and amortized on a straight-line basis over the term of the debt facility.

1. Significant accounting policies: (continued)

Financial instruments and derivatives (continued):

Unrealized holding gains and losses on trading securities are included in earnings. A decline in the market value of any held-to-maturity security below cost that is deemed to be other-than-temporary results in an impairment to reduce the carrying amount to fair value. To determine whether an impairment is other-than-temporary, the Company considers all available information relevant to the collectability of the security, including past events, current conditions, and reasonable and supportable forecasts when developing estimate of cash flows expected to be collected. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year end, forecasted performance of the investee, and the general market condition in the geographic area or industry the investee operates in.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values and the change in fair value is included in the Consolidated Statements of Operations. None of the derivatives were designated in hedging relationships for accounting purposes.

(r) Fair Value Measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(s) Stock Option Plan

The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity-classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value using the Black-Scholes option-pricing model.

1. Significant accounting policies: (continued)

(t) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of future tax assets, the portion of advances in aid of construction payments that will not be repaid, assessments of asset retirement obligations, and the fair value of financial instruments, derivatives and stock options. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements not yet adopted and accounting framework

(a) CICA Section 1582 – Business Combinations

In January 2009, the CICA issued Handbook Section 1582, Business combinations, which replaces the existing standards. This section establishes the standards for the accounting of business combinations, and states that all assets and liabilities of an acquired business will be recorded at fair value. Estimated obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and that restructuring charges will be expensed in the periods after the acquisition date. This standard is applied prospectively to business combinations with acquisition dates on or after January 1, 2011. Earlier adoption is permitted. The Company did not early adopt this new standard.

(b) Accounting framework

As an SEC registrant, APUC has elected to report its financial statements under US GAAP commencing with the first quarter of 2011. The change in accounting framework will be applied retrospectively to all prior periods and appropriate changes to accounting policies will be made in order to comply with US GAAP. Those US GAAP policies are expected to be consistent with the policies applied in preparing the reconciliation reflected in note 24 of these consolidated financial statements.

3. Unit for share exchange (the "Unit Exchange Offer")

In order to effect a change in business structure from an income trust to a corporation, on October 27, 2009, APCo's unitholders exchanged 100% of the outstanding trust units of APCo for a new class of common shares ("New Common Shares") of APUC (formerly Hydrogenics Corporation or Hydrogenics), on a one for one basis. Immediately prior to this exchange, under a Plan of Arrangement, Hydrogenics transferred all of its operations and substantially all its assets and liabilities to a newly created company ("New Hydrogenics"). The pre-existing publicly traded shares of Hydrogenics were contemporaneously redeemed for shares of New Hydrogenics and thus the pre-existing publicly traded shares of Hydrogenics no longer exist. As a result of the Unit Exchange Offer, APUC paid New Hydrogenics $11,307. The transaction resulted in the Unitholders of APCo indirectly holding their interest in APCo as shareholders of APUC. Excluding shares issued under the CD Exchange Offer (as defined and described below), the number of common shares of APUC outstanding immediately after completion of the Unit Exchange Offer was exactly the same as the number of APCo's trust units outstanding immediately before the Unit Exchange Offer.

Accounting treatment of the Unit Exchange Offer

The Unit Exchange Offer is required to be accounted for as a change in business form using the continuity of interests method of accounting in accordance with Emerging Issues Committee abstract 170, "Conversion of an Unincorporated Entity to an Incorporated Entity". Under the continuity of interests method of accounting, the transfer of the assets, liabilities and equity of APCo to APUC were recorded at their net book values as at the effective date of the Transaction. As a result, for accounting purposes, APUC is required to be accounted for as though it were a continuation of APCo but with its capital reflecting the exchange of APUC Shares for Trust Units and therefore certain terms such as shareholder/unitholder, dividend/distribution and share/unit may be used interchangeably throughout these consolidated financial statements. For the periods reported up to the effective date of the Unit Exchange Offer, all payments to unitholders were in the form of trust unit distributions, and after that date all payments to shareholders are in the form of dividends.

Comparative figures presented in the consolidated financial statements of APUC include all amounts previously reported by APCo. In addition, a future tax asset of $66,954 related to the tax attributes of Hydrogenics Corporation was recognized on the transaction date. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration paid to New Hydrogenics was reflected as a deferred credit of $55,647 on the transaction date to be recognized in income as an income tax expense recovery as the future income tax assets are utilized. As a result of the corporatization transaction, APUC also recorded an increase to future tax liabilities. This adjustment reflects the tax impact of recording future tax assets and liabilities for temporary differences that are reversing or settling prior to 2011 which were previously not recorded since prior to the transactions these temporary difference reversals were not previously expected to be taxed in APCo.

APUC expensed corporatization costs of $3,460 during 2009 in relation to the Unit Exchange Offer.

Contemporaneously with the Unit Exchange Offer a convertible debenture exchange offer ("the CD Exchange Offer) was made by APUC to debentureholders of APCo. The CD Exchange Offer is more fully described in note 10.

4. Acquisitions

(a) Acquisition of electrical generation and regulated distribution utility

In 2009, APUC entered into an agreement to acquire an electrical generation and regulated distribution utility in a partnership with Emera Inc. ("Emera"). APUC will own 50.001% and Emera will own 49.999% of shares of the newly formed California Pacific Utility Ventures LLC, which has agreed to acquire through its wholly owned subsidiary California Pacific Electric Company ("Calpeco") a California-based electricity distribution utility and related generation assets (the "California Utility"). The California Utility provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region.

In connection with the acquisition, on April 23, 2009 Emera also agreed to a conditional treasury subscription for approximately 8.5 million shares of APUC at a price of $3.25 per share. The proceeds of the subscription receipts are intended to fund a portion of the cost of acquisition of the California Utility.

As of December 31, 2010, APUC has incurred costs of $2,210 (2009 - $1,084) related to the acquisition of the California Utility. These costs are recorded as deferred transaction costs and are included in other assets on the Consolidated Balance Sheet.

As of December 31, 2010, APUC has incurred costs of $965 related to the transition of the California Utility. These costs are recorded as other capital assets and are included in other assets on the Consolidated Balance Sheet.

As of December 31, 2010, APUC has incurred costs of $871 related to the financing of the California Utility. These costs are recorded in other assets on the Consolidated Balance Sheet.

The acquisition of the California Utility by Calpeco closed subsequent to year end on January 1, 2011 for a purchase price of approximately US $131,790, subject to certain working capital and other closing adjustments. Delivery of the shares under the subscription receipts occurred simultaneously with the closing of the acquisition.

(b) Agreement to Acquire Electric and Gas Utilities

On December 9, 2010 APUC announced that Liberty Energy Utilities Co. ("Liberty Energy"), APUC's utility subsidiary, had entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company, a regulated electric utility, and EnergyNorth Natural Gas Inc. a regulated natural gas utility from National Grid USA ("National Grid") for total consideration of US $285,000.

The transaction is subject to U.S. state and federal regulatory approval and is expected to close in the fall of 2011. As of December 31, 2010, APUC has incurred costs of $1,889 (2009 - $nil) related to the acquisition. These costs are recorded as deferred transaction costs and are included in other assets on the Consolidated Balance Sheet.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share. The issuance of these subscription receipts is subject to regulatory approval.

(in thousands of Canadian dollars except as noted and amounts per share)

4. Acquisitions (continued)

(c) Acquisition of Hydroelectric Generation Assets ("Tinker Acquisition")

On January 12, 2010, APUC acquired certain electrical generating facility assets located in New Brunswick and Maine. The acquisition consisted of three hydroelectric generating stations, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick. The acquisition also included five thermal generating stations and certain regulated New Brunswick Independent System Operator transmission lines located in proximity to the generating facilities. In connection with the Tinker Acquisition, on February 4, 2010, APUC also acquired a related energy services business ("Energy Services Business").The Energy Services Business retails the electricity generated by the Tinker facilities to commercial and industrial customers in northern Maine.

The total purchase price, including acquisition costs, was $40,671. Acquisition costs of $390 were paid in 2009 which were recorded as deferred transaction costs and included in other assets on the consolidated balance sheet at December 31, 2009 and included in acquisition costs in 2010.

The acquisition has been accounted for using the purchase method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been preliminarily allocated to net assets acquired as follows:

Working capital (net of cash received of $1)	$ 69
Property, plant and equipment	40,817
Intangible asset – energy sales contracts	4,421
Non-current future income tax liability	(1,262)
Derivative liability – energy forward purchase contracts (note 22)	(3,374)
Total cash consideration	$40,671

The allocation of the purchase price has been based upon the fair values of the assets and liabilities as of the date of acquisition.

(in thousands of Canadian dollars except as noted and amounts per share)

4. Acquisitions (continued)

(d) Acquisition of Water Utility System ("the Galveston Utility")

On March 17, 2010 Liberty Water, a wholly owned subsidiary of APUC, acquired water distribution and wastewater collection system located near Galveston, Texas for a total purchase price of $2,038. The Galveston Utility provides water distribution and wastewater collection services to approximately 260 equivalent residential connections.

The acquisition has been accounted for using the purchase method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been allocated to net assets acquired as follows:

Property, plant and equipment	$2,023
Intangible asset	15
Total cash consideration	$2,038

(e) Acquisition of Entrada Del Oro Sewer Company

In 2008, the Company entered into an agreement to acquire the shares of Entrada Del Oro Sewer Company located in Arizona, for $707 (US$670).

In accordance with the purchase and sale agreement, APUC is required to make additional payments to the previous owners for each additional customer connected to the utility. These payments continue until 2018. As of December 31, 2010, APUC has paid $83 (U.S. $80) (2009 - $87 (U.S. $78)) as a growth premium, and increased long term investments and notes receivable by a similar amount.

(in thousands of Canadian dollars except as noted and amounts per share)

4. Acquisitions (continued)

(f) Highground Capital Corporation

In 2008, the Company entered into an agreement with Highground Capital Corporation ("Highground"), CJIG Management Inc. ("CJIG"), which is the manager of Highground and a related party of the Company controlled by the shareholders of Algonquin Power Management Inc ("APMI") who are current or former executives of the Company. Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and the Company issued trust units to the Highground shareholders and CJIG.

The Company initially recorded the trust units issued at their fair value of $7.69 per unit which, net of transaction costs of $767, resulted in proceeds of the trust units being initially recorded at a value of $26,203. By December 31, 2010, the Company has received consideration and issued equity as follows:

Consideration received:	
Cash and assets received prior to December 31 2008	$26,203
Cash received in 2009	983
Cash received in 2010	170
	$27,356

In 2009, APUC's consideration received from the acquisition exceeded $26,970, the minimum contemplated under the agreements, and, as a result APUC is entitled to 50% of any additional proceeds from the assets formerly owned by Highground. CJIG is entitled to the remaining 50% of any proceeds in excess of the minimum amount. During 2010, APUC received $170 (2009 - $983) from CJIG as APUC's share of the 50% of additional proceeds from the further liquidation of the assets held by Highground. This has been recorded as an increased amount assigned to the equity originally issued.

The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having an approximate principal amount of $2,227. APUC's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded as additional proceeds when received from CJIG.

(in thousands of Canadian dollars except as noted and amounts per share)

5. Long-term investments and notes receivable

Long-term investments and notes receivable consist of the following:

	2010	2009
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 8,197	$ 8,344
25% of Class B non-voting shares of Cochrane Power Corporation	5,775	6,544
45% partnership interest in the Algonquin Power (Rattle Brook) Partnership	3,790	3,827
Investment in Entrada Del Oro (note 4 (e))	568	709
Red Lily Subordinated loan, interest at 12.5% (note 5 (a))	6,565	
Red Lily Senior loan, interest at 6.31% (note 5 (a))	6,100	—
Chapais Énergie, Société en Commandite 12.1% interest in Tranche A and Tranche B term loans The loans bear interest at the rate of 10.789% and 4.91%, respectively	3,329	3,701
Silverleaf resorts loan, interest at 15.48% (note 5 (b))	2,010	—
Note Receivable - Twin Falls. The note bears interest at the rate of 6.75%	740	759
	37,074	23,884
Less: current portion	(1,172)	(414)
Total long term investments and notes receivable	$35,902	$23,470

The above notes are secured by the underlying assets of the respective facilities. There is no allowance for doubtful account in regards to the notes receivable as at December 31, 2010 and 2009.

(a) Red Lily I

On April 19, 2010, the Company entered into agreements to provide development, construction, operation and supervision services related to the construction, commissioning and operation of a 26.4 megawatt wind energy facility ("Red Lily I") in south-eastern Saskatchewan.

The equity in Red Lily I ('the Partnership") is owned by an independent investor. The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Partnership. APUC's commitment under the senior debt facility is to advance up to $13,000 of the Tranche 2 senior debt. The third party lender has also committed to provide $31,000 of senior debt to the Partnership. The senior debt will earn an interest rate of 6.31% and will mature five years following commissioning of the project. The subordinated debt will earn an interest rate of 12.5%. The senior debt is secured by substantially all the assets of the Partnership.

5. Long-term investments and notes receivable (continued)

(a) Red Lily I (continued)

In 2010, APUC funded $6,100 of senior debt to the project (2009 - $nil) and $6,565 in subordinated debt to the Partnership.

A second tranche of subordinated debt for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced five years following commissioning of the project. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including APUC's portion. The subordinated debt earns an interest rate of 12.5%, the principal matures 25 years following commissioning of the project but is repayable by Red Lily in whole or in part at any time after five years, without a pre-payment premium. The subordinated debt is secured by substantially all the assets of the Partnership but is subordinated to the senior lenders debt.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated debt of up to $19,500, exercisable for a period of 90 days commencing five years from the date of commissioning of the project.

(b) Silverleaf Resorts Inc – Hill County

On July 29, 2010, Liberty Water, a wholly owned subsidiary of APUC, made an investment in its Hill Country facility, a part of Silverleaf Resorts Inc.'s ("SRI") facilities in Comal County, Texas. The investment of $2,094 (U.S. $2,021) was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. This investment has been recorded in property, plant and equipment as additional capacity conveyed by SRI together with note receivable for funds advanced by APUC.

The note has a 10 year term and bears interest at 15.48%. The note is repayable in cash to the extent expansion does not form part of the rate base of the utility during the 10 year term. To the extent that the cost of the expansion becomes part of the rate base of the utility, the note will be assigned as payment to Silverleaf for the expansion costs with the excess received in cash.

(c) Land Fill Gas

In 2009, APUC wrote off the remaining $1,103 (U.S. - $999) principal balance of the note receivable related to its land fill gas facility which was previously recorded in other long term investments.

(in thousands of Canadian dollars except as noted and amounts per share)

6. Property, plant and equipment

Property, plant and equipment consist of the following:

2010

	Cost	Accumulated amortization	Net book value
Land	$ 11,709	$ —	$ 11,709
Facilities	921,032	231,098	689,934
Equipment	48,747	21,314	27,433
	$981,488	$ 252,412	$729,076

2009

	Cost	Accumulated amortization	Net book value
Land	$ 11,323	$ —	$ 11,323
Facilities	953,826	224,244	729,582
Equipment	30,325	21,880	8,445
	$995,474	$ 246,124	$749,350

Facilities include cost of $94,606 (2009 - $94,606) and accumulated amortization of $27,962 (2009 - $25,426) related to facilities under capital lease or owned by consolidated variable interest entities, and $10,542 (2009 - $11,551) of construction in process. Amortization expense of facilities under capital lease was $2,536 (2009 - $2,537). In addition $3,731 (2009—$5,926) of contributions received in aid of construction have been credited to facilities cost. Equipment includes cost of $4,402 (2009 - $4,096) and accumulated amortization of $2,149 (2009 - $1,857) related to equipment under capital lease. Amortization expense of equipment under capital lease was $292 (2009 - $302). In 2010, interest of $nil (2009 - $nil) was capitalized to facilities within property, plant and equipment.

In December 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1,836 representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates.

In December 2010, the equipment at the Crossroads thermal facility in New Jersey met the conditions for asset held for sale. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $656, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

In December 2009, APCo decided to dispose of its investments in its last remaining Landfill Gas assets and its biomass joint venture Drayton Valley Power. APCo therefore tested these investments for recoverability using a net realizeable value valuation technique. As a result, APCo determined that these assets were impaired as at December 31, 2009 and recognized an impairment charge on property, plant and equipment of $5,354 representing the difference between the carrying value of the assets and their net fair value. In 2009 APCo also recorded $500 related to costs associated with decommissioning the land fill gas facilities and recorded this on the Statement of Operations with a corresponding increase in other long term liabilities.

(in thousands of Canadian dollars except as noted and amounts per share)

7. Intangible assets

Intangible assets consist of the following:

2010

	Cost	Accumulated amortization	Net book value
Power sales contracts	$102,980	$ 45,345	$57,635
Customer relationships	18,811	2,912	15,899
Energy sales contract	4,228	3,876	352
Licenses and agreements	683	683	—
	$126,702	$ 52,816	$73,886

2009

	Cost	Accumulated amortization	Net book value
Power sales contracts	$119,533	$ 51,333	$68,200
Customer relationships	20,279	2,564	17,715
Licenses and agreements	696	682	14
	$140,508	$ 54,579	$85,929

Estimated amortization expense for intangibles for the next five years is: $6,526 in 2011, $6,120 in 2012, $6,117 in 2013, $6,070 in 2014, and $6,070 in 2015.

8. Other Assets

Other assets consist of the following:

	2010	2009
Regulatory assets	$2,164	$1,713
California Utility – deferred financing	871	—
California Utility – other capital assets	965	—
Wind development assets	788	788
Deferred transaction costs -		
California Utility (note 4(a))	2,210	1,084
Tinker acquisition (note 4 (c))	—	390
Energy North and Granite State acquisition (note 4(b))	1,888	—
Other	731	867
	$9,617	$4,842

Regulatory assets are amortized over the period of rate recovery granted by the regulator.

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long-term liabilities

Long term liabilities consist of the following:

	2010	2009
Senior Secured Revolving Credit Facility: Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus 0.95%. The effective rate of interest for 2010 was 2.13% (2009 – 1.71%).	$64,500	$94,000
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matures on October 31, 2011. Monthly interest and quarterly principal payments totaling $1,741 (2009—$1,649). The effective rate of interest for 2010 was 1.81% (2009 – 1.78%).	68,789	70,271
Liberty Water Senior Unsecured: U.S. $50,000 senior unsecured note, interest rate of 5.6% matures December 22, 2020. The note is interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and an annual principal repayment of U.S. $5,000 thereafter.	48,876	—
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly installments of $402 and maturing December, 2027.	39,870	40,594
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2010 is 1.33% (2009 – 1.44%).	19,096	20,179
Litchfield Park Service Company Bonds: 1999 and 2001 IDA Bonds. Interest rates of 5.87% and 6.71% repayable in blended semi-annual installments maturing October 2023 and October 2031. Principal payments of U.S. $270 (2009 – U.S. $240). The balance of these notes at December 31, 2010 was U.S. $4,112 and U.S. $7,884, respectively (2009 – U.S. $4,325 and U.S. $7,983).	11,931	12,936
Senior Debt Chute Ford: Interest rate of 11.6% repayable in monthly interest and principal installments of $64 and maturing April, 2020.	4,336	4,580

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long term liabilities (continued)

	2010	2009
Bella Vista Water Loans:		
Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March, 2020 and December, 2017. The balance of these notes at December 31, 2010 was US$1,384 and US$95 respectively (2009 – US$1,478 and US$102).	1,489	1,707
Bonds Payable:		
Obligation to the City of Sanger due October 1, 2011 at interest rates varying from 5.45% to 5.55%. U.S. $230 (2009 - U.S. $445).	229	468
Other	15	37
	$259,131	$244,772
Less: current portion	(70,490)	(3,360)
	$188,641	$241,412

Subsequent to year end, APCo renewed its senior secured revolving credit facility in the amount of $142,000 (the "Facility") for a three year term with its Canadian bank syndicate. The Facility now has a maturity date of February 14, 2014.

At December 31, 2010, $64,500 (2009 - $94,000) has been drawn on the Facility. In addition, the availability of the revolving credit facility has been reduced for certain outstanding letters of credit in amounts totaling $33,122 (2009 - $33,108). Therefore, APCo had $44,400 of undrawn committed and available bank facilities as at December 31, 2010.

The terms of the Facility contain certain financial covenants including debt service ratios and various leverage ratios which can limit the amounts available for borrowing. Based on current covenants at December 31, 2010, APCo is able to access the entire amount of the Facility. The facility is secured by a fixed and floating charge over all APCo entities.

On December 22, 2010 APUC completed a $50,000 private placement debt financing commitment for its subsidiary, Liberty Water Co. ("Liberty Water"). The notes are senior unsecured with a ten year maturity date of December 2020 and bears interest at 5.6%. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and annual principal repayments of U.S. $5,000 thereafter. As of December 31, 2010, Liberty Water incurred deferred financing costs of $854 which is amortized to interest expense over the term of the loan using the effective interest rate method.

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long term liabilities (continued)

Total long term debt is reported net of deferred financing costs. Certain of our long-term debt has been issued at a subsidiary level relating to a specific operating facility and is secured by the respective facility with no other recourse to APUC or APCo. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions/dividends to APCo and APUC from specific facilities. As at December 31, 2010 APUC and its subsidiaries were in compliance with all debt covenants.

Interest paid on the long-term liabilities was $9,064 (2009 - $9,446).

Principal payments due in the next five years and thereafter are:

2011	$ 70,490
2012	1,543
2013	1,695
2014	66,354
2015	2,041
Thereafter	117,008
	$ 259,131

The AirSource senior debt matures in October, 2011. As of December 31, 2010, the outstanding amount due has been recorded within the current portion of the long-term liabilities on the Consolidated Balance Sheet.

10. Convertible Debentures

Contemporaneously with the Unit Exchange Offer, on October 27, 2009 (see note 3), holders of APCo's convertible debentures exchanged their convertible debentures for convertible debentures of APUC (the "New Debentures") or for New Common Shares of APUC resulting in APCo's debentureholders becoming debentureholders or shareholders of APUC.

Pursuant to the CD Exchange Offer, $63,755 of the outstanding Series 1 debentures of APCo were exchanged for new Series 1 convertible unsecured subordinated debentures of APUC in a principal amount of $66,943, and $21,209 of the current Series 1 debentures of APCo were exchanged for 6,607,027 shares of APUC. In addition, all of the outstanding Series 2 convertible debentures of APCo were exchanged for New Series 2 convertible unsecured subordinated debentures of APUC in a principal amount of $59,967.

Accounting treatment of the CD Exchange Offer

The terms of the CD Exchange Offer are considered a modification of the terms of the existing debentures of APCo rather than an extinguishment since the present value of the cash flows of the liability component of both the New Series 1 and New Series 2 debentures did not change by more than 10% as compared to the terms of the original debentures exchanged. Accordingly, the consolidated balance sheet reflects the convertible debentures at their original carrying values, net of transaction costs associated with the CD Exchange Offer. These transaction costs are recorded as deferred costs and are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

10. Convertible Debentures (continued):

Under the terms of the CD Exchange Offer, the New Series 1 convertible debentures of APUC were issued at a face value of 105% of the principle amount of the original Series 1 debentures of APCo. The change in conversion price of the New Series 1 convertible debentures under the CD Exchange Offer resulted in the fair value of the conversion feature increasing by $1,179 as compared to the original Series 1 debentures. The change in conversion price of the New Series 2 convertible debentures under the CD Exchange Offer resulted in the fair value of the conversion feature decreasing from the original Series 2 convertible debentures carrying value of $479 to $308. The changes of $1,179 and $171 in the fair value of the conversion features on the Series 1 and Series 2 debentures are recorded as a change in the discount on debt, with an offsetting adjustment to equity. The discounts on debt are treated as additional debt issuance costs which are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

In addition, an element of the CD Exchange Offer to the Series 1 convertible debenture holders was an option to convert a portion of Series 1 convertible debentures to equity at a rate of 311.52 APUC Shares for each $1 principal amount of Series 1 convertible debentures. This resulted in an accounting debt settlement expense of $1,252 which is included in corporatization costs on the consolidated statement of operations. The CD Exchange Offer resulted in the holders of the Series 1 convertible debentures converting $21,209 of the outstanding principal balance of Series 1 convertible debentures into 6,607,027 common shares of APUC.

The pro rata portion of existing deferred financing charges associated with the Series 1 convertible debentures of $306 is recorded in the amount recorded for the common shares issued on conversion. In addition, a proportionate allocation of the total deferred transaction costs associated with the CD Exchange Offer is recorded as part of the issuance costs of the new APUC shares. APUC incurred transaction costs of $1,453 related to the CD Exchange Offer for the Series 1 convertible debentures of which $1,090 is allocated to the convertible debentures as debt issuance costs and $363 has been allocated to issuance costs related to the new APUC shares. APUC also incurred costs of $1,453 related to the CD Exchange Offer for the Series 2 convertible debentures which has been allocated to the convertible debentures as debt issuance costs.

The exchange of $63,755 of Series 1 convertible debentures that were not converted to shares, after adjustment for the 5% premium included in the CD Exchange Offer, resulted in an increase in the principal balance of the new Series 1 convertible debentures to $66,943. The increase of $3,188 is accounted for as additional debt issuance costs and is amortized to interest expense over the term of the new convertible debentures using the effective interest rate method.

10. Convertible Debentures (continued):

On December 2, 2009, APUC issued 63,250 convertible unsecured subordinated debentures (Series 3) at a price of $1 per debenture for gross proceeds of $63,250 and net proceeds of $60,518. The debentures are due June 30, 2017 and bear interest at 7.00% per annum, payable semi-annually in arrears on June 30 and December 31 each year. The convertible debentures are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares per $1 principal amount of debentures. The debentures cannot be redeemed by APUC on or before December 31, 2012. APUC performed an evaluation of the embedded conversion option and determined that its value was $4,275 and as a result this portion of the debenture is classified as equity with the remaining amount classified as a liability. The liability component of the convertible debentures increases to their face value over the term of the debentures and the offsetting charge to earnings is classified as interest expense on the consolidated statements of operations.

Total interest paid on the convertible debentures in 2010 was $13,053 (2009 - $9,696).

(in thousands of Canadian dollars except as noted and amounts per share)

10. Convertible Debentures (continued):

2010	New Series 1	New Series 2	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$ 4.08	$ 6.00	$ 4.20	
Carrying value at December 31, 2009	60,728	56,241	56,288	173,257
Conversion to shares (Note12), net of costs	(4,094)	—	(311)	(4,405)
Amortization and accretion	1,000	425	698	2,123
Carrying value at December 31, 2010	$ 57,634	$ 56,666	$ 56,675	$170,975
Face value at December 31, 2010	$ 62,470	$ 59,967	$ 62,905	$185,342

2009	New Series 1	New Series 2	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$ 4.08	$ 6.00	$ 4.20	
Carrying value at December 31, 2008	83,178	57,249	—	140,427
Issued pursuant to December 2, 2009 offering	—	—	63,250	63,250
Change in equity component	(1,179)	171	(4,275)	(5,283)
Conversion to shares (Note12), net of costs	(21,209)	(33)	—	(21,242)
Deferred issue costs	(784)	(1,453)	(2,731)	(4,968)
Amortization and accretion	722	307	44	1,073
Carrying value at December 31, 2009	$ 60,728	$ 56,241	$ 56,288	$173,257
Face value at December 31, 2009	$ 66,943	$ 59,967	$ 63,250	$190,160

(in thousands of Canadian dollars except as noted and amounts per share)

11. Other long-term liabilities

Other long term liabilities consist of the following:

	2010	2009
Advances in aid of construction (note 1(l))	$21,267	$14,952
Deferred water rights inducement	3,008	3,089
Customer deposits	1,985	2,405
Capital Leases		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	524	456
Other	5,099	5,351
	31,883	26,253
Less: current portion	(1,011)	(1,025)
	$30,872	$25,228

Principal payments due in the next five years and thereafter are:

2010	$ 1,011
2011	165
2012	78
2013	68
2014	—
Thereafter	30,561
	$31,883

Interest paid on other long-term liabilities was $29 (2009 - $37).

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' equity/Unitholders' equity

Number of common shares/trust units:

	2010	2009
Common shares / Trust units, beginning of period	93,064,120	77,574,372
Issued on conversion of Algonquin (AirSource) Power LP exchangeable units	—	2,005,721
Conversion of convertible debentures (Note 11)	1,178,478	6,607,027
Issued pursuant to management internalization	1,180,180	—
Issued pursuant to offering	—	6,877,000
Common shares, end of period	95,422,778	93,064,120

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are outstanding.

On October 27, 2009, pursuant to the Unit Exchange Offer (see note 3), APCo's unitholders exchanged 100% of the outstanding trust units of APCo for a new class of common shares ("New Common Shares") of APUC on a one for one basis. As a result, the existing unitholders of APCo became shareholders of APUC and APCo became a subsidiary of APUC.

On December 2, 2009, APUC issued 6,877,000 common shares at $3.35 per common share for gross proceeds of $23,038 before issuance costs of $1,495, ($1,002 net of tax) for net proceeds of $21,533.

On June 29, 2010, the Company issued 1,180,180 shares valued at $4,763 pursuant to the Management Internalization Agreement signed on December 21, 2009 (note 16). The issuance of shares and final settlement was approved by the Company's shareholders at its annual general meeting held on June 23, 2010.

In 2010, $4,473 principal amount of New Series 1 Debentures were converted at the option of the holders at a price of $4.08 for each share into 1,096,335 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $4,094 has been recorded as share capital.

In 2010, $345 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 82,142 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $311 has been recorded as share capital.

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' equity/Unitholders' equity (continued):

At a special meeting of Exchangeable Unitholders of Algonquin (AirSource) Power LP in December 2009, amendments were approved to amend the agreements related to the Exchangeable Units to allow the exchange of Exchangeable Units for common shares of APUC, as opposed to units of APCo, and to change the definition of "Redemption Date" as set out in the Partnership Agreement. As a result of these changes, APUC exercised the compulsory acquisition provisions of the Exchangeable Units on December 31, 2009 and all of the remaining outstanding Exchangeable Units were exchanged for 532,074 common shares of APUC, as per the formula set out in the original agreements. As a result, there are no outstanding Exchangeable Units after January 1, 2010 and consequently the non-controlling interest balance at December 31, 2010 is reduced to $nil (2009 - $nil). At December 31, 2010 no amount was included in non-controlling interest (2009 - $1,928) in the statement of operations for the allocation of earnings to the exchangeable unitholders (AirSource Power LP).

Shareholders equity/Unitholders' Equity consists of the following:

	2010	2009
Balance of Common shares/Trust Units, beginning of period	$ 781,274	$ 721,953
Issued on conversion of Airsource exchangeable units	—	14,487
Conversion of convertible debentures, net of costs	4,621	21,825
Common Share issue, net of costs	—	22,026
Common shares issued pursuant to management internalization (Note 14)	4,763	—
Proceeds from liquidation of Highground assets (Note 4(f))	170	983
Balance of Shares, end of the period	$ 790,828	$ 781,274
Contributed surplus – stock options	108	—
Equity component of convertible debentures (Note 10)	5,640	5,763
Shareholders' equity, end of period	$ 796,576	$ 787,037

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' capital (continued)

Stock Option Plan

On June 23, 2010, the Company's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Optionholders may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of a qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

On August 12, 2010, the Board approved the grant of 1,102,041 options to senior executives of the Company. The options allow for the purchase of common shares at a price of $4.05, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2011, 2012 and 2013. Options may be exercised up to eight years following the date of grant.

The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The following assumptions were used in determining the fair value of share options granted:

	2010
Risk-free Interest	2.9%
Expected Volatility	29.2%
Expected dividend yield	5.9%
Expected Life	8 years
Grant date fair value per option	$ 0.61

The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical rates in dividends of our shares.

12. Shareholders' capital (continued)

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. At December 31, 2010, APUC recorded $108 (2009 - $nil) in compensation expense. As at December 31, 2010, there was $562 (2009 - $nil) of total unrecognized compensation costs related to non-vested options granted under the Plan. The cost is expected to be recognized over a period of 1.9 years.

No share options were exercised in 2010 or exercisable at December 31, 2010. The intrinsic value of the 1,102,041 non-vested shares as at December 31, 2010 was $1,069 (2009-$nil).

Shareholders' Rights Plan

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan").

The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

(in thousands of Canadian dollars except as noted and amounts per share)

13. Income taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 31% (2009 - 33%). The differences are as follows:

	2010	2009
Expected income tax expense / (recovery) at Canadian statutory rate	$ (45)	$ 5,302
Increase (decrease) resulting from:		
Accounting losses (income) of APCo taxed at the unitholder level	—	(20,790)
Recognition of deferred credit	(6,636)	—
Differences in tax rates in subsidiaries and changes in tax rates	(203)	(1,848)
Change in valuation allowances	(7,486)	10,688
Foreign exchange loss on intercompany items (US)	(6,228)	(13,464)
Non deductible expenses and other	370	2,185
Income tax recovery	$(20,228)	$(17,927)

The Unit Exchange Offer (Note 3), together with changes in tax rates enacted in December 2009, resulted in APUC recognizing a future income tax asset of $60,014 and a deferred credit in relation to this asset of $49,879 as at December 31, 2009. The deferred credit is being recorded to reduce income tax expense in proportion to the net reduction in the future income tax asset that gave rise to the deferred credit. Current and future income taxes have been provided in respect of taxable income and temporary differences related to the Company and its subsidiaries.

For the years ended December 31, 2010 and 2009, income/(loss) before taxes consists of the following:

	2010	2009
Canadian operations	$(4,152)	$ 7,284
U.S. operations	4,007	8,783
	$ (145)	$16,067

(in thousands of Canadian dollars except as noted and amounts per share)

13. Income taxes (continued)

Income tax expense attributable to income/(loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2010			
Canada	$ 200	$ (518)	$ (318)
United States	(269)	(19,641)	(19,910)
	$ (69)	$(20,159)	$(20,228)
Year ended December 31, 2009			
Canada	$ 313	$ 4,481	$ 4,794
United States	84	(22,805)	(22,721)
	$ 397	$(18,324)	$(17,927)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2010 and 2009 are presented below:

	2010	2009
Future tax assets:		
Non-capital losses, investment tax credits, currently non-deductible interest expense and financing costs	$ 115,472	$ 104,455
Unrealized foreign exchange differences on intercompany notes	17,860	25,138
Customer advances in aid of construction	5,559	5,393
Foreign exchange hedges and interest rate swaps	1,459	2,865
Total future tax assets	140,350	137,851
Less: Valuation allowance	(27,907)	(35,393)
Total future tax assets	112,443	102,458
Future tax liabilities:		
Property, plant and equipment	(96,554)	(96,960)
Intangible assets	(7,639)	(8,409)
Other	(1,696)	(2,131)
Total future tax liabilities	(105,889)	(107,500)
Net future tax asset / (liability)	$ 6,554	$ (5,042)

The valuation allowance for future tax assets as of December 31, 2010 and 2009 was $27,907 and $35,393, respectively. The net change in the total valuation allowance was a decrease of $7,486 in 2010 and an increase of $10,688 in 2009. The valuation allowance at December 31, 2010 was primarily related to operating losses and foreign exchange losses on the intercompany debts that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of future tax assets, management considers whether it is more likely than not that some portion or all of the future tax assets will not be realized. The ultimate realization of future tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of future tax liabilities (including the impact of available carryback and carryforward periods), projected future taxable income, and tax-planning strategies in making this assessment.

(in thousands of Canadian dollars except as noted and amounts per share)

13. Income taxes (continued)

Future income taxes are classified in the financial statements as:

	2010	2009
Future current income tax asset	$ 14,015	$ 14,566
Future non-current income tax asset	74,006	61,219
Future current income tax liability	(514)	(913)
Future non-current income tax liability	(80,953)	(79,914)
	$ 6,554	$ (5,042)

As at December 31, 2010, the Company had non capital loss carryforwards available to reduce future years taxable income, which expire as follows:

Year of expiry	Non-capital loss carryforward
2014	$ 29,023
2015	33,957
2019	135,095
2020 and onwards	69,604
	$ 267,679

14. Related party transactions

On December 21, 2009, the Board of Directors of APUC (the "Board") reached an agreement with APMI to internalize all management functions of the APCo which were provided by APMI. APUC acquired APMI's interest in the management services agreement, with consideration paid in the form of issuance of 1,158,748 APUC shares (the "Shares"). For accounting purposes, the expense has been measured at $4,693 using a price for each share of $4.03, the adjusted closing market price on December 21 2009, the date the agreement was ratified.

Up to December 21, 2009, APMI provided management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2009, APMI was paid on a cost recovery basis for all costs incurred and charged $850. APMI was also entitled to an incentive fee of 25% on all distributable cash (as defined in the management agreement) generated in excess of $0.92 per trust unit.

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for 2010 were $327 (2009 - $331).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year, APUC incurred costs in connection with the use of the aircraft of $430 (2009 - $367) and amortization expense related to the advance against expense reimbursements of $112 (2009 - $153). At December 31, 2010, the remaining amount of the advance was $554 (2009 - $666) and is recorded in other assets.

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008 growing to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units are entitled to cash distributions of $266 for the year ended December 31, 2010 (2009 - $292).

Pursuant to the agreement entered into on June 27, 2008 between the Company, Highground and CJIG (Note 4(f)), APMI was entitled to a fee of approximately $240 from the Company. This fee was paid in 2009.

14. Related party transactions (continued)

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1,800 of which APUC agreed to pay APMI $105. This amount has been accrued and included in accounts payable on the consolidated balance sheet.

APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. APUC has agreed to acquire APMI's interest in this royalty for an amount of $600. APMI is also entitled to a development fee of up to $400 following commercial operation of the project and has agreed to permit the Board to determine the portion of such fee which will be paid following commercial operation of the facility. APUC received and recognized $210 in other revenue related to this fee in the twelve months ended December 31, 2010.

APUC has operation and maintenance service agreements with three hydroelectric generating facilities owned by affiliates of APMI. As a result of these agreements, APUC employees operate these hydroelectric generating facilities owned by affiliates of APMI. These facilities are charged on a cost recovery basis for time and material incurred at these sites.

Under these arrangements, as at December 31, 2010 amount due from the above related party transactions was $718 (December 31, 2009 - $1,028) and amounts due to related parties was $901 (December 31, 2009 - $827).

A member of the Board of Directors of APUC is an executive at Emera Inc ("Emera"). A contract with a subsidiary of Emera to purchase energy on Independent System Operator New England ("ISO NE") and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of $1,368 (2009 - $nil) which was included as an operating expense on the consolidated statement of operations.

In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During 2010 APUC paid U.S. $196 (2009 - $nil) in relation to this contract. In the same period, APUC issued a letter of credit to a subsidiary of Emera in an amount of U.S. $500 in conjunction with this contract. Subsequent to December 31, 2010, this letter of credit was replaced with a corporate guarantee.

On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation), the parent company of Maine Public Service Company ("MPS"). Subsequent to the date of this acquisition, the Energy Services Business sold electricity of U.S. $144 (2009 – nil) to MPS.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

15. Commitments and Contingencies

(a) Land and Water Leases

Certain of the Company's operating entities have entered into agreements to lease either land, water rights or both that are used in the generation of electricity or to pay, in lieu of property tax, an amount based on electricity production. The terms of these leases have varying maturity dates that continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. APUC incurred costs of $2,231 during 2010 (2009 - $2,823) in respect of these agreements for all of its operating entities.

(b) Contingencies

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC's exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

(c) Commitments

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated potential remedial measures involving capital expenditures of approximately $17,129 which may be required to comply with the legislation and which would be invested over a five year period or longer. APUC continues to explore alternatives to reduce or mitigate these potential capital expenditures, including technical alternatives and cost sharing with other stakeholders.

An AirSource affiliate, St. Leon Wind Energy LP ("St. Leon LP") has entered into right-of-way agreements (collectively, the "Land Rights"), with approximately 50 local landowners, providing for a minimum term of 40 years. The Land Rights agreements provide for an annual rent payable per MW-hr generated from turbines installed on the land rented, subject to a minimum payment per wind turbine. Land without wind turbines is leased at a cost on a per acre basis. The total commitment over the term of the St. Leon power purchase agreement is estimated at $3,605.

16. Cash dividends

All cash dividends of the Company are made on a discretionary basis as determined by the Board of Directors of the Company. In 2010, the Company paid quarterly dividends of $0.06 per share. For the year ended December 31, 2010, the Company paid cash dividends to shareholders totaling $22,765 (2009 - $18,999) or $0.24 per unit / per share (2009 - $0.24).

Total distributions to the unitholders of the AirSource exchangeable units for 2010 were $nil (2009 - $323) which was recorded as a reduction in non controlling interest on the consolidated balance sheet.

(in thousands of Canadian dollars except as noted and amounts per share)

17. Non cash working capital and Supplemental cashflow Information

The change in non cash working capital is comprised of the following:

	2010	2009
Accounts receivable	$(6,813)	$ 6,720
Income tax receivable	1,143	395
Prepaid expenses	1,153	(1,842)
Accounts payable and accrued liabilities	5,050	(6,042)
Current income tax liability	195	(536)
	$ 728	$(1,305)

The following table sets forth non-cash investing and financing activities and other cash flow information:

	2010	2009
Taxes & Interest paid:		
Income taxes paid / (received)	$ (285)	$ 873
Interest paid	$21,562	$19,956
Non-cash transactions:		
Property installed by developers and conveyed	$ 2,541	$ 223

18. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of the weighted average number of shares outstanding during the year. The weighted average number of shares outstanding during the year are as follows:

	2010	2009
Weighted average shares – basic	94,338,193	79,830,906
Shares issuable on conversion of AirSource exchangeable units	—	1,499,222
Weighted average shares – diluted	94,338,193	81,330,128

Shares or Trust units issuable on conversion of exchangeable units are calculated at the year end based on the weighted average exchangeable units outstanding during the year and applying the rate of exchange. The shares potentially issuable as a result of the convertible debentures and under stock option plans are excluded from this calculation as they are anti-dilutive.

(in thousands of Canadian dollars except as noted and amounts per share)

19. Interest, dividend and other income

Interest, dividend and other income includes the following items:

	2010	2009
Interest income	$1,138	$ 710
Dividend income	2,928	2,928
Equity income	431	361
Gain on sale of land and land rights	—	1,451
Other	465	951
	$4,962	$6,401

20. Other revenue

Other revenue consists of the following:

	2010	2009
Natural gas sales	$ (109)	$ 588
Hydro mulch sales	1,318	3,260
Red Lily development fees	209	—
Red Lily construction services	1,913	—
	$3,331	$3,848

21. Segmented Information

APUC has two broad operating segments: APCo which owns or has interests in 48 renewable energy facilities and 14 thermal energy facilities representing more than 490 MW of installed electrical generation capacity; and Liberty Utilities which owns and operates 19 utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois.

Within APCo there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Within Liberty Utilities, Liberty Water provides transportation and delivery of water and wastewater in its service areas.

The operations and assets for these segments are as follows:

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy and Liberty Water. The development activities are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the gain on financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. Dividend income was previously allocated to the Thermal division based on the operations of the underlying investment. In 2010, Management reviewed the performance of these investments separately from the facilities that the Company manages directly. Interest expense is allocated to the divisions based on the project level debt related to the facilities in each division. Interest expense on the revolving credit facility and other administrative costs were previously allocated to the corporate segment. In 2010, Management's evaluation of divisional performance considered an allocation between the reporting segments based on a percentage of the reporting segments share of the total property, plant and equipment and intangible assets. The interest rate swaps relate to specific debt facilities and gains and losses are allocated in the same manner as interest expense. Amounts relating to the convertible debentures are reported in the corporate segment. The comparative figures have been reclassified to conform to the allocation adopted this year.

The operations and assets for these segments are as follows:

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

Year ended December 31, 2010

	Algonquin Power			Liberty Utilities	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 80,117	$ 52,609	$132,726	$ —	$ —	$132,726
Waste disposal fees	—	9,039	9,039	—	—	9,039
Water reclamation and distribution	—	—	—	37,786	—	37,786
Other revenue	2,122	1,209	3,331	—	—	3,331
Total revenue	82,239	62,857	145,096	37,786	—	182,882
Operating expenses	29,481	46,296	75,777	22,074	—	97,851
	52,758	16,561	69,319	15,712	—	85,031
Other administration costs	(4,674)	(1,825)	(6,499)	(1,890)	(6,497)	(14,886)
Foreign exchange loss	—	—	—	—	528	528
Interest expense	(7,742)	(782)	(8,524)	(1,908)	(15,180)	(25,612)
Interest, dividend and other income	783	495	1,278	85	3,599	4,962
Gain / (loss) on derivative financial instruments	(5,486)	—	(5,486)	—	4,383	(1,103)
Write down of property plant and equipment	(1,836)	(656)	(2,492)	—	—	(2,492)
Amortization of property, plant and equipment	(17,233)	(11,362)	(28,595)	(7,659)	(175)	(36,429)
Amortization of intangible assets	(6,670)	(2,774)	(9,444)	(700)	—	(10,144)
Net earnings / (loss) before income taxes, and non-controlling interest	9,900	(343)	9,557	3,640	(13,342)	(145)
Property, plant and equipment	$412,549	$151,260	$563,809	$164,775	$ 492	$729,076
Intangible assets	28,287	23,104	51,391	22,495	—	73,886
Total assets	467,979	195,181	663,160	205,770	111,987	980,917
Capital expenditures	2,331	11,596	13,927	6,644	260	20,831
Acquisition of operating entities	40,281	—	40,281	5,243	—	45,524

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

Year ended December 31, 2009

	Algonquin Power			Liberty Utilities	Corporate	Total
	Renewable Energy	Thermal Energy	Total			
Revenue						
Energy sales	$ 68,227	$ 62,209	$130,436	$ —	$ —	$ 130,436
Waste disposal fees	—	14,468	14,468	—	—	14,468
Water reclamation and distribution	—	—	—	38,513	—	38,513
Other revenue	—	3,848	3,848	—	—	3,848
Total revenue	68,227	80,525	148,752	38,513	—	187,265
Operating expenses	22,279	57,299	79,578	23,158	—	102,736
	45,948	23,226	69,174	15,355	—	84,529
Other administration costs	(5,791)	(2,812)	(8,603)	(226)	(2,733)	(11,562)
Foreign exchange loss	—	—	—	—	1,261	1,261
Interest expense	(7,345)	(1,098)	(8,443)	(2,049)	(10,895)	(21,387)
Interest, dividend and other income	1,226	821	2,047	1,368	2,986	6,401
Gain / (loss) on derivative financial instruments	2,682	(829)	1,853	343	15,122	17,318
Write down of property plant and equipment	—	(5,354)	(5,354)	—	—	(5,354)
Write down of note receivable	—	(1,103)	(1,103)	—	—	(1,103)
Amortization of property, plant and equipment	(16,934)	(13,087)	(30,021)	(8,557)	—	(38,578)
Amortization of intangible assets	(2,654)	(3,916)	(6,570)	(735)	—	(7,305)
Earnings / (loss) from operations before income taxes, non-controlling interest, and corporatization costs	17,132	(4,152)	12,980	5,499	5,741	24,220
Management internalization costs	—	—	—	—	(4,693)	(4,693)
Other corporatization costs	—	—	—	—	(3,460)	(3,460)
Net earnings / (loss) before income taxes, and non-controlling interest	17,132	(4,152)	12,980	5,499	(2,412)	16,067
Property, plant and equipment	$403,192	$176,171	$579,363	$169,987	$ —	$ 749,350
Intangible assets	30,602	30,436	61,038	24,891	—	85,929
Total assets	451,936	245,582	697,518	203,444	112,451	1,013,413
Capital expenditures	1,114	3,521	4,635	6,174	107	10,916
Acquisition of operating entities	—	—	—	(1,177)	—	(1,177)

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2010 or 2009: Hydro Québec 14% (2009 - 17%), Pacific Gas and Electric 10% (2009 - 12%), Manitoba Hydro 15% (2009 – 15%), and Connecticut Light and Power 4% (2009 - 18%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

Geographic Segments

APUC and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2010	2009
Revenue		
Canada	$ 75,108	$ 82,364
United States	107,774	104,901
	$182,882	$187,265
Property, plant and equipment		
Canada	$466,205	$440,490
United States	262,871	308,860
	$729,076	$749,350
Intangible assets		
Canada	$ 43,305	$ 47,916
United States	30,581	38,013
	$ 73,886	$ 85,929
Other assets		
Canada	$ 1,414	$ 1,916
United States	8,203	2,926
	$ 9,617	$ 4,842

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments

a) Fair Value of financial instruments

	2010 Carrying amount	2010 Fair value	2009 Carrying amount	2009 Fair value
Cash	5,146	5,146	2,796	2,796
Short-term investments	3,674	3,674	40,010	40,010
Accounts receivable	27,082	27,082	20,484	20,484
Restricted cash	3,563	3,563	4,316	4,316
Notes receivables	18,744	18,744	4,460	4,460
Total financial assets	58,209	58,209	72,066	72,066
Accounts payable and accrued liabilities	33,506	33,506	33,219	33,219
Dividends payable	5,721	5,721	1,857	1,857
Long-term liabilities	259,131	261,321	244,772	247,119
Other long-term liabilities	31,883	31,883	26,253	26,253
Convertible debentures	170,975	216,769	173,257	198,892
Interest swaps	5,440	5,440	8,226	8,226
Energy forward purchase	378	378	—	—
Foreign exchange contracts	45	45	1,469	1,469
Total financial liabilities	507,079	555,063	489,053	517,035

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value at December 31, 2010 and 2009 due to the short-term maturity of these instruments.

Long term investments and notes receivable include equity instruments and notes receivable. The equity instruments do not have a quoted market price in an active market, and fair value cannot be reliably measured. Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities and convertible debentures at fixed interest rates and variable rates. The estimated fair value is calculated using the current interest rates.

Advances in aid of construction included in other long-term liabilities (note – 1 (l)) do not bear interest and the amount to be repaid is subject to uncertainty and estimation. The carrying value is estimated based on historical payment patterns with the amount estimated to not be paid being recorded as a contribution in aid of construction which reduces the carrying amount of the related assets. The fair value is considered to approximate the book value.

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments (continued)

b) Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2010 are as follows:

	Level 1	Level 2	Level 3	Total
Interest swap –St Leon	—	5,440	—	5,440
Energy forward purchase	—	378	—	378
Foreign exchange contracts	—	45	—	45
Total financial liabilities at fair value	—	5,863	—	5,863

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or lever 3 during the year ended December, 31, 2010. No assets or liabilities are measured at fair value on a recurring basis using unobservable inputs (Level 3).

c) Effect of derivative instruments on the Consolidated Statement of Operations

Loss/(gain) on derivative financial instruments consist of the following:

	2010	2009
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$(1,424)	$(15,682)
Interest rate swaps	(2,787)	(7,424)
Energy forward purchase contracts	(2,931)	—
Total change in unrealized loss/(gain) on derivative financial instruments	$(7,142)	$(23,106)
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (620)	$ 284
Interest rate swaps	5,929	5,504
Energy forward purchase contracts	2,936	—
Total realized loss/(gain) on derivative financial instruments	$ 8,245	$ 5,788
Loss/(gain) on derivative financial instruments	$ 1,103	$(17,318)

22. Financial instruments (continued)

(d) Risk Management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents and accounts receivable. The Company limits its exposure to credit risk with respect to cash equivalents by maintaining minimal cash balances and ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from Power Generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of US$4,996 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments (continued)

Credit Risk (continued)

As at December 31, 2010 the Company's exposure to credit risk for these financial instruments was as follows:

	December 31, 2010	
	Canadian $	US $
Cash and cash equivalents	$ 1,878	$ 3,285
Short term investments	—	3,694
Accounts receivable	11,877	15,328
Allowance for Doubtful Accounts	—	(40)
Note Receivable	16,733	2,021
	$ 30,488	$24,288

There are no material past due amounts in accounts receivable.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2010, in addition to cash on hand of $5,146 the Company had $44,400 available to be drawn on its senior debt facility. The senior credit facility contains covenants which may limit amounts available to be drawn.

	Total	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations	$ 259,131	$ 70,490	$ 3,238	$ 68,395	$ 117,008
Convertible Debentures	185,342	—	—	62,469	122,873
Interest on long term debt obligations	164,830	25,670	48,198	35,889	55,073
Accounts Payable	33,506	33,506	—	—	—
Derivative financial instruments:					
Currency Forwards	45	45	—	—	—
Interest Rate Swaps	5,439	1,959	2,504	976	—
Commodity Swap	378	378	—	—	—
Lease Payments	523	212	243	68	—
Other obligations	9,255	466	931	931	6,927
Total obligations	$ 658,449	$ 132,726	$ 55,114	$ 168,728	$ 301,881

22. Financial instruments (continued)

Foreign Currency Risk

The Company uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts. Based on the fair value of the forward contracts using the exchange rates as at December 31, 2010, the exercise of these forward contracts will result in the use of $45 in fiscal 2012. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of $0.10 at December 31, 2010 with a corresponding change in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $300, increasing the expected cash generated during fiscal 2012 by $300.

As at December 31, 2010, APUC had outstanding foreign exchange forward contracts to sell US$3,000 (2009 - $39,760) at an average rate of $1.00 (2009- $1.02) and having a fair value liability of $45 (2009 - $1,469).

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility as well as interest earned on its cash on hand. The Company has performed sensitivity analysis on interest rate risk at December 31, 2010 to determine how a change in interest rates would impact equity and net earnings:

Senior credit facility

The Company's senior debt facility has a balance of $64,500 as at December 31, 2010. Assuming the current level of borrowings, a 1% change in the variable rate charged would impact interest expense by $645 during the twelve months ended December 31, 2010. Although this underlying debt with the project lenders carries a variable rate of interest tied to Canadian Bank's prime rate, the Company had previously entered into a fixed for floating interest rate swap related to $100,000 of this debt covering the period between June 30, 2008 and December 2010. APUC effectively fixed its interest expense on this portion of the facility at a rate of 3.24% in 2009 and 4.18% in 2010. At December 31, 2010, the fair value of the interest rate swap was $nil as it had expired (2009 - $3,260 liability). This swap arrangement requires the payment of a fixed rate of interest by the Company in exchange for receipt of a variable rate of interest. The Company has not used hedge accounting for this instrument and therefore changes in fair value are recorded in earnings as they occur and form part of the gain or loss on financial instruments on the consolidated statements of operations.

22. Financial instruments (continued)

Airsource –St Leon

The Algonquin (AirSource) Power LP ("Airsource") project debt at the St. Leon facility has a balance of $68,789 as at December 31, 2010. Assuming the current level of borrowings, a 1% change in the variable rate charged would have impacted interest expense by $687 during the twelve months ended December 31, 2010. Although this underlying debt with the project lenders carries a variable rate of interest tied to Canadian Bank's prime rate, in 2006 the Company entered into a fixed for floating interest rate swap related to this debt until September 2015. This swap arrangement requires the payment of a fixed rate of interest by the Company in exchange for receipt of a variable rate of interest that mirrors the underlying debt's interest payment schedule. These payments effectively minimize volatility in the cash interest on this debt facility through an offset for any change to interest payments as a result of market rate fluctuations. At December 31, 2010, the fair value of the interest rate swap was a net $5,440 liability (2009 - $4,966). APUC has elected not to use hedge accounting for the swap transaction and records the fair value of the swap on the consolidated balance sheets. Any gain or loss in fair value is recognized in the consolidated statements of operations.

Sanger

The Company's project debt at the Sanger facility has a balance of U.S. $19,200 as at December 31, 2010. Assuming the current level of borrowings, a 1% change in the variable interest rate charged would impact interest expense by $192 during the twelve months ended December 31, 2010. This analysis assumes that all other variables, in particular foreign currency rates, remain constant.

Market Risk

APUC provides energy requirements to various customers under contract at fixed rates. While the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

APUC anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In 2010, APUC acquired short term forward energy purchase contracts from the Tinker Acquisition related to the energy services business. APUC has committed to acquire approximately 12,000 MW-hrs of energy over the next 2 months at an average rate of approximately $70.00 per MW-hr. The fair value of these forward energy hedge contracts at December 31, 2010 was a net liability of $378 (2009 - $nil).

23. Capital disclosures

The Company views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

The Company's objectives when managing capital are:

- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital.
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets.
- To ensure generation of cash is sufficient to fund sustainable distributions to Unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

The Company monitors its cash position on a regular basis to ensure funds are available to meet current operating as well as capital expenditures. In addition, the Company regularly reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

(in thousands of Canadian dollars except as noted and amounts per share)

24. U.S. GAAP Reconciliation

The Company follows generally accepted accounting principles in Canada (GAAP), which differs in certain material respects from generally accepted accounting principles in the United States and from practices prescribed by the United States Securities and Exchange Commission (U.S. GAAP). The following information reconciles these consolidated financial statements to U.S. GAAP.

Reconciliation of net earnings under Canadian GAAP to U.S. GAAP

	Year ended December 31	
	2010	2009
Net earnings, Canadian GAAP	$ 19,639	$ 31,257
Adjustments, net of tax of $563 (2009- $991)		
Convertible debentures (b),(d)	572	(1,850)
Deferred transaction costs (f)	(2,261)	(1,106)
Non controlling interest (c)	—	2,251
Total adjustments	(1,689)	(705)
Net earnings, U.S. GAAP	17,950	30,552
Other comprehensive income/(loss), Canadian and U.S. GAAP	(51,133)	(27,270)
Total comprehensive income/(loss), U.S. GAAP	(33,182)	3,282
Basic net earnings per share	$ 0.19	$ 0.38
Diluted net earnings per share	$ 0.19	$ 0.38

The Application of U.S. GAAP results in difference to the following balance sheet items:

	December 31, 2010		December 31, 2009	
	Canadian GAAP	U.S. GAAP	Canadian GAAP	U.S. GAAP
Property, plant and equipment	729,076	728,686	749,350	749,350
Other assets – deferred transaction costs (f)	4,098	—	1,474	—
Deferred financing costs (b(iii),(e))	258	5,991	200	6,001
Long-term liabilities (e)	259,131	259,973	244,772	244,970
Convertible debentures (b(iii),(e)(d)	170,975	181,758	173,257	185,600
Future income tax liability (h)	81,467	79,956	80,827	79,879
Non-controlling interest (c)	—	—	—	—
Temporary equity (a), (c)	—	—	—	—
Additional paid-in-capital (b(ii)),(g)	—	1,496	—	1,487
Shareholders' capital (a),(b),(c),(d),(g)	796,576	795,443	787,037	785,827
Deficit	(347,802)	(357,034)	(344,676)	(352,219)

(in thousands of Canadian dollars except as noted and amounts per share)

24. US GAAP Reconciliation (continued)

Reconciliation of deficit under Canadian GAAP to U.S. GAAP

	As at December 31	
	2010	2009
Deficit, Canadian GAAP	$(347,802)	$(344,676)
Adjustments, net of tax		
Convertible debentures (b), (d)	(1,311)	(1,883)
Non controlling interest (c)	(4,554)	(4,554)
Deferred transaction costs (f)	(3,367)	(1,106)
Total adjustments	(9,232)	(7,543)
Deficit, U.S. GAAP	$(357,034)	$(352,219)

Description of significant differences

a) Unit Exchange Offer

On October 27, 2009, Algonquin Power Income Fund (the "Fund") completed a reverse take-over transaction (the "Transaction") of Hydrogenics Corporation ("Hydrogenics") which resulted in the Fund's Unitholders becoming shareholders in Hydrogenics which was immediately renamed Algonquin Power & Utilities Corp. As a result, the Fund itself became a wholly owned subsidiary of APUC. For Canadian and U.S. GAAP purposes, APUC is considered a continuation of the Fund except for the legal capital of the Fund which is adjusted to reflect the legal capital of APUC.

Prior to the Transaction, the Fund's trust units contained a redemption feature which was required for the Fund to retain its Canadian mutual fund trust status. For Canadian GAAP purposes, the Trust units were considered permanent equity and were presented as a component of Unitholders' equity. Under U.S. GAAP, equity with a redemption feature is presented outside of permanent equity, as temporary equity between the liability and equity sections of the balance sheet. As such, the trust units of $721,736 were reclassed from permanent equity to temporary equity for U.S. GAAP purposes up to October 27, 2009.

24. US GAAP Reconciliation (continued)

b) CD Exchange Offer

Contemporaneously with the Unit Exchange Offer, on October 27, 2009 a convertible debenture exchange offer (the "CD Exchange Offer") was made by APUC to debentureholders of the Fund to allow them to receive debentures issued by APUC.

(i) Similar to Canadian GAAP, under U.S. GAAP the change in coupon rates and maturity terms of the convertible debentures under the CD Exchange Offer is considered to be a debt modification and not an extinguishment based on the Company's evaluation of the changes in cash flows and fair value of the conversion options under the terms of the revised debt agreements. The consolidated balance sheet of APUC under Canadian GAAP reflects the convertible debentures at their original carrying values, net of an allocation of transaction costs of approximately $2,544 associated with the CD Exchange Offers. Under U.S. GAAP these transaction costs of $2,544 were expensed when incurred in 2009 since the costs were paid to third parties and not the debtor. This results in a reduction of $337 (2009 - $53) in the amount of effective interest on convertible debentures under U.S. GAAP in comparison to Canadian GAAP.

(ii) The change in conversion price of the Series 1 and Series 2 convertible debentures under the CD Exchange Offer results in a change in the fair value of the conversion feature of $1,179 and $308, respectively. Under U.S. GAAP, the combined fair value of the conversion feature of $1,487 is recorded as a discount on debt, with an offsetting entry to additional paid-in-capital. Under Canadian GAAP, the offsetting entry is recorded in equity. An adjustment of $1,388 (2009 – 1,487), net of a converted portion of $99 (2009 - $nil) reflects the reclassification of conversion feature recorded as equity under Canadian GAAP, to additional paid-in capital under U.S. GAAP.

(iii) Under U.S. GAAP the adjustment for the conversion of $21,209 of the Series 1 convertible debentures into common shares does not result in any Canadian GAAP difference in earnings.

However, under Canadian GAAP the pro rata share of existing deferred financing charges associated with the Series I debentures of $306 is recorded as a charge against equity upon conversion of $21,209 of debentures into common shares, with a corresponding adjustment to convertible debentures. Under U.S. GAAP, the same net amount is charged against equity however, the corresponding adjustment of $306 is made to deferred financing costs to reflect the different classification of deferred charges for Canadian and U.S. GAAP purposes.

24. US GAAP Reconciliation (continued)

c) Non controlling interest

Exchangeable units ("AirSource Exchangeable Units") were issued by Algonquin (AirSource) Power LP ("Algonquin AirSource"), a subsidiary of the Fund, when Algonquin AirSource acquired AirSource Power Fund I LP on June 29, 2006. The AirSource Exchangeable Units entitled the holders to receive distributions which are equivalent to the Fund's distributions, as long as the facility which was acquired upon acquisition of AirSource generated adequate cash flows.

Under Canadian GAAP the AirSource Exchangeable Units were recorded in the Company's consolidated financial statements as "Non controlling interest". The portion of income or loss attributable to this non controlling interest and distributions to holders of the exchangeable units are recorded as a reduction to the carrying amount of the non controlling interest. Under U.S. GAAP the AirSource Exchangeable Units are classified along with the Trust Units outside of permanent equity as temporary equity since they are able to be converted at the holder's option to the Fund's Trust Units. The temporary equity was initially recorded at an amount equal to the redemption value based on the terms of the AirSource Exchangeable Units. Any increase in the redemption value of the AirSource Exchangeable Units is recorded as an adjustment through deficit and any downward adjustment is restricted only to the extent of previously recorded increases in the carrying amount arising from such adjustments. No adjustment was required to the carrying amount of the AirSource Exchangeable Units in temporary equity. Under U.S. GAAP the proportion of income attributable to the AirSource Exchangeable Units non controlling interest of $nil (2009 - $2,251) is recorded to deficit rather than through earnings and distributions to the AirSource Exchangeable Unit holders of $nil (2009 - $323) are recorded as a charge to deficit.

On December 31, 2009, all remaining Air Source units were converted to APUC shares. Under both Canadian and U.S. GAAP, when the AirSource Exchangeable Units are converted to shares, the non controlling interest (temporary equity under U.S. GAAP) on the consolidated balance sheet is reduced on a pro-rata basis together with a corresponding increase in shares. However, since the carrying amount of the non-controlling interest per Canadian GAAP differs from the carrying amount in temporary equity per U.S. GAAP, the amount transferred to shareholders' capital differs by $4,554.

d) Convertible debentures

Under Canadian GAAP, the carrying amount of the convertible debentures was bifurcated into equity (the conversion option) and debt whereas under U.S. GAAP, the convertible debentures do not have the features that would require bifurcation. Accordingly, an adjustment to the balance sheets of $4,252 (2009- $4,275) in relation to the Series 3 Convertible Debentures reflects the reclassification of the value attributed to the equity components recorded under Canadian GAAP, to convertible debentures.

Under Canadian GAAP, the accretion of the residual carrying value of the convertible debentures to the face value of the convertible debentures over the life of the instrument is charged to interest expense. Under U.S. GAAP, no such accretion is required if the conversion feature is not required to be bifurcated. This GAAP difference resulted in a reversal of accretion of $426 (2009 - $27) recorded under Canadian GAAP.

24. US GAAP Reconciliation (continued)

e) Financing costs

The Company records financing costs associated with issuance of debt instruments as a reduction to long-term liabilities and convertible debentures under Canadian GAAP. Under U.S. GAAP, such costs are presented in assets as deferred financing costs. Accordingly, the reclassification adjustment reflects a cumulative increase of $840 (2009 - $197) in long-term liabilities and $4,893 (2009 - $5,604) in convertible debentures with a corresponding increase in deferred financing costs of $5,733 (2009 - $5,801).

f) Business combinations and transaction costs

Under Canadian GAAP, the Company recorded $3,014 (2009 - $1,474) of deferred transaction costs in connection with future business acquisitions. Under U.S. GAAP, acquisition-related costs are expensed as incurred.

g) Stock-based compensation

Under U.S. GAAP, the stock-based compensation of $108 (2009 - $nil) is recorded as compensation expense with a balancing entry to additional paid-in-capital. Under Canadian GAAP, the balancing entry is recorded in contributed surplus. An adjustment of $108 (2009 - $nil) reflects the reclassification of stock-based compensation recorded as contributed surplus under Canadian GAAP to additional paid-in capital under U.S. GAAP.

h) Income taxes

The adjustments reflect the future tax impact of the above U.S. GAAP adjustments.

i) Cash flow statement

The consolidated cash flow statement prepared in accordance with Canadian GAAP presents substantially the same information that is required under U.S. GAAP with the exception of deferred transaction costs in connection with future acquisitions of $3,014 (2009 - $1,474) as described in note g) which under U.S. GAAP would be reflected in as cash used in operating activities unlike in Canadian GAAP where it is classified as investing activity. Additionally the Company presents a subtotal in its Canadian GAAP statement of cash from operating activities before change in non-cash operating working capital. This subtotal is not permitted under U.S. GAPP.

j) Adoption of new accounting pronouncements

i) Credit quality:

Effective December 31, 2010, APUC adopted ASU 2010-20, Receivables (Topic 310): Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses, which increases disclosures about credit quality of financing receivables and the allowance for credit losses, and requires disclosures to be made at a greater level of disaggregation. The adoption of this guidance in 2010 has been reflected in the Company's disclosures relating to notes receivable.

ii) Fair value disclosure:

Effective January 1, 2010, APUC adopted ASU 2010-06, Improving Disclosures about Fair Value Measurements which requires more detailed information on fair-value disclosures. The adoption of this guidance in 2010 is reflected in note 22 of the consolidated financial statements.

24. US GAAP Reconciliation (continued)

iii) Variable interest entities:

Effective January 1, 2010, APUC adopted FAS 167: Amendments to FASB Interpretation No. 46(R) which addresses (1) the effects on certain provisions of FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities, as a result of the elimination of the qualifying special-purpose entity concept in FASB Statement No. 166, Accounting for Transfers of Financial Assets, and (2) the application of certain key provisions of Interpretation 46(R), including those in which the accounting and disclosures under the Interpretation do not always provide timely and useful information about an enterprise's involvement in a variable interest entity. The adoption of this standard did not have an impact on the Company's financial statements.

iv) Subsequent events:

In February 2010, the FASB issued ASU No. 2010-09 "Subsequent Events (ASC Topic 855) "Amendments to Certain Recognition and Disclosure Requirements" ("ASU No. 2010-09"). ASU No. 2010-09 requires an entity that is an SEC filer to evaluate subsequent events through the date that the financial statements are issued and removes the requirement for an SEC filer to disclose a date, in both issued and revised financial statements, through which the filer had evaluated subsequent events.

k) Recently issued accounting pronouncements not yet adopted

i) Revenue recognition:

In October 2009, the FASB issued ASU 2009-13, Revenue Recognition (Topic 605): Multiple-Deliverable Revenue Arrangements—a consensus of the FASB Emerging Issues Task Force ("ASU 2009-13"). ASU 2009-13 requires entities to allocate revenue in an arrangement using estimated selling prices of the delivered goods and services based on a selling price hierarchy. The ASU eliminates the residual method of revenue allocation and requires revenue to be allocated using the relative selling price method. ASU 2009-13 should be applied on a prospective basis for revenue arrangements entered into or materially modified in fiscal years beginning on or after June 15, 2010, with early adoption permitted. The Company does not expect adoption of ASU 2009-13 to have a material impact on the Company's consolidated financial statements.

ii) Goodwill:

In December 2010, the FASB issued ASU 2010-28, Intangibles—Goodwill and Other (Topic 350): *When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts*, *a consensus of the FASB Emerging Issues Task Force (Issue No. 10-A*). ASU 2010-28 modifies Step 1 of the goodwill impairment test under ASC Topic 350 for reporting units with zero or negative carrying amounts to require an entity to perform Step 2 of the goodwill impairment test if it is more likely than not that a goodwill impairment exists. ASU 2010-28 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2010. The Company expects that the adoption of ASU 2010-28 in 2012 will not have a material impact on its consolidated financial statements.

25. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

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Section 4: EX-99.3 (MANAGEMENT'S DISCUSSION & ANALYSIS FOR THE YEAR ENDED DECEMBER 31, 2010)

Exhibit 99.3

ALGONQUIN
POWER & UTILITIES

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per share and convertible debenture amounts or where otherwise noted)

Management of Algonquin Power & Utilities Corp. ("APUC"), the corporation continuing the business of Algonquin Power Co. ("Algonquin"), formerly Algonquin Power Income Fund (the "Fund"), has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2010. This Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2010 and 2009. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 2, 2011.

Caution concerning forward-looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "adjusted net earnings" and "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") are used throughout this MD&A. The terms “adjusted net earnings” and Adjusted EBITDA are not recognized measures under Canadian generally accepted accounting principles (“GAAP”). There is no standardized measure of “adjusted net earnings” and Adjusted EBITDA, consequently APUC’s method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of “adjusted net earnings” and Adjusted EBITDA can be found throughout this MD&A.

Conversion to a Corporation

On October 27, 2009, Algonquin completed a transaction (the "Unit Exchange Offer") which provided Algonquin's unitholders the opportunity to exchange their trust units of Algonquin, on a one-for-one basis, for common shares of an existing corporation. This existing corporation, Hydrogenics Corporation, transferred all of its operations and existing shares to a new corporation pursuant to a Plan of Arrangement prior to completion of the Unit Exchange Offer. The name of Hydrogenics Corporation was changed to Algonquin Power & Utilities Corp. following closing of the transaction.

The transaction resulted in the unitholders of Algonquin becoming shareholders of APUC, with no changes to Algonquin's underlying business operations. Under the continuity of interest method of accounting, APUC's transfer of assets, liabilities and equity of Algonquin are recorded at their net book value in APUC's financial statements as at October 27, 2009. As a result of this conversion, certain terms such as shareholder/unitholder and dividend/distribution may be used interchangeably throughout this MD&A. Prior to October 27, 2009, all distributions to unitholders were in the form of trust unit distributions. References to APUC shall mean Algonquin with respect to activities and results occurring prior to October 27, 2009 and shall mean APUC with respect to activities and results occurring on or after October 27, 2009.

Overview

APUC is incorporated under the Canada Business Corporations Act. APUC currently conducts its business primarily through two separate and autonomous subsidiaries: Algonquin Power Co. ("APCo") owns and operates a diversified portfolio of renewable energy assets and Liberty Utilities Co. ("Liberty Utilities") owns and operates a portfolio of North American utilities.

APCo generates and sells electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. As at December 31, 2010, APCo owns or has interests in 44 hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds debt securities in a 26 MW wind powered generating station recently completed in Saskatchewan. The renewable energy facilities generally sell their electrical output pursuant to long term power purchase agreements ("PPAs") with major utilities and have a weighted average remaining contract life of 16 years. Similarly, the 12 thermal energy facilities that APCo has an ownership and interest in operate under PPAs and have a weighted average remaining contract life of 6 years with a combined generating capacity of approximately 210 MW[1].

Liberty Utilities provides utility services related to electricity, natural gas, water and wastewater services. Liberty Water Co. ("Liberty Water"), a subsidiary of Liberty Utilities, provides water and wastewater utility services to approximately 75,000 customers through 19 water distribution and wastewater collection and treatment utility systems located in four U.S. States (Arizona, Illinois, Missouri and Texas). These utilities operate under rate regulation, generally overseen by the public utility commissions of the States in which they operate.

Liberty Energy Utilities Co. ("Liberty Energy"), a subsidiary of Liberty Utilities, provides local electrical and natural gas utility services. On January 1, 2011, in partnership with Emera Inc. ("Emera"), Liberty Energy acquired a California-based electricity distribution utility and related generation assets, and now provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region (the "California Utility"). Liberty Energy has entered into agreements to acquire two additional utilities which currently provide electric and natural gas distribution services to approximately 125,000 customers in New Hampshire.

Business Strategy

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the power and utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through growth in dividends supported

1 During the fourth quarter, APCo determined that the generating capacity reported for each of its facilities was more appropriately reported based on APCo's effective percentage ownership interest in the facility, rather than the total installed capacity of the facility; as a result, the generating capacity values set out in respect of some of the facilities included in APCo's generating portfolio have been reduced from prior periods

by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon APUC strives to deliver annualized per share earnings growth of 5% and to grow its dividend supported by growth in cash flows, earnings and investment prospects.

APUC understands the importance of the dividend to its shareholders. APUC currently pays quarterly cash dividends to shareholders of $0.06 per share or $0.24 per share per annum. On March 3, 2011, the Board of Directors of APUC (the "Board") approved an annual dividend increase of $0.02 per common share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per common share. The Board also declared a dividend of $0.065 per share payable on April 15, 2011 to the shareholders of record on March 31, 2011.

APUC believes this level of dividends will continue to allow for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Any increases in the level of dividends paid by APUC will be at the discretion of the Board and dividend levels shall be reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to the Company. APUC strives to achieve its results within a moderate risk profile consistent with top-quartile North American power and utility operations.

Independent Power: APCo develops, owns and operates a diversified portfolio of electrical energy generation facilities. Within this business there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates APCo's hydroelectric and wind power facilities. The Thermal Energy division operates co-generation, energy-from-waste, and steam production facilities. The Development division seeks to deliver continuing growth to APCo through development of APCo's greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within APCo's existing portfolio of renewable energy and thermal energy facilities.

Utilities: Liberty Utilities owns and operates utilities through its two wholly-owned subsidiaries, Liberty Energy and Liberty Water, in the electricity distribution, transmission and generation as well as natural gas distribution, water distribution and wastewater treatment sectors. These utilities share certain common infrastructure to generate economies of scale to support best-in-class customer care for its utility ratepayers. The underlying business strategy is to be a leading provider of safe, high quality and reliable utility services while providing stable and predictable earnings from its utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings by identifying acquisition opportunities which accretively expand its business portfolio.

Major Highlights

Liberty Water Rate Cases

During the year ended December 31, 2010, Liberty Water completed rate case proceedings at nine utilities in Arizona and Texas which on an annualized basis are expected to contribute an additional U.S. $10.2 million in revenue in Liberty Water. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. $1.1 million in annual revenue requirement is expected to be concluded by the first quarter of 2011.

California Utility Acquisition and Senior Debt Financing

On January 1, 2011, following receipt of all U.S. state and federal regulatory approvals, APUC announced that, in partnership with Emera, Liberty Energy had acquired the assets comprising the California Utility. Liberty Energy owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, California Pacific Electric Company ("Calpeco").

The acquisition of the California Utility was completed for a gross purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. Upon closing, Emera exchanged previously announced subscription receipts into 8.532 million APUC common shares at a purchase price of $3.25 per share. The proceeds of the subscription receipts were utilized to fund Liberty Energy's ownership share of the cost of acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility entered into on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

Granite State/EnergyNorth Acquisition

On December 9th, 2010 APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company ("Granite State"), a regulated electric distribution utility, and EnergyNorth Natural Gas, Inc. ("EnergyNorth"), a regulated natural gas distribution utility from National Grid USA ("National Grid") for total consideration of U.S. $285.0 million.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011. Financing of the acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Energy is targeting a capital structure with not more than 50% debt to total capital, consistent with investment grade utilities. In connection with these acquisitions, Emera has committed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. The issuance of these subscription receipts is subject to regulatory approval.

Red Lily Wind Project

On February 28, 2011 APUC announced that the 26.4 MW wind generation facility in southeastern Saskatchewan ("Red Lily I") commenced commercial operation under the PPA. APUC's commitment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011, such interest payments and fees are expected to be approximately $2.4 million. APUC has the option to formally exchange its debt investment for a 75% equity position in the facility in 2016. See *Renewable Energy - Divisional Outlook* for more discussion of this project.

New Wind Projects Under Development

75 MW Wind - Amherst Island: On February 25, 2011 APUC announced that the Ontario Power Authority ("OPA") awarded a contract to the wholly owned 75 MW Amherst Island Wind Project, located on Amherst Island in the village of Stella, approximately 25 kilometers southwest of Kingston, Ontario. The contract was awarded as part of the second round of the OPA's Feed-in Tariff ("FIT") program.

The project, which will be developed by APCo, is currently contemplated to use more efficient Class III wind turbine generator technology that is estimated to produce approximately 247 GW-hrs of power annually. Funding of the total capital costs, currently estimated to be $220 million, will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 months.

On December 21st, 2010 APUC announced that Hydro-Québec Distribution has accepted proposals for the purchase of energy from the 24 MW Saint-Damase and 24 MW Val-Éo wind power generating projects. The projects were submitted with support from APUC in response to the community based call for offers announced in the spring of 2009.

25MW Wind - Saint-Damase: The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APUC. The first 24 MW phase of the project is currently envisioned to consist of twelve 2 MW ENERCON Canada Inc. ("ENERCON") E-82 wind turbine generators, producing approximately

86,000 MWh annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

25 MW Wind - Val-Éo: The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APUC. The first 24 MW phase of the project is expected to be comprised of eight 3 MW ENERCON E-101 wind turbine generators, producing approximately 66,000 MW-hrs annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interests of APUC in the Saint-Damase and Val- Éo projects is subject to final negotiations with the partners in the projects but, in any event, will not be less than 50% and 25%, respectively. Final funding of the projects will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began for both projects in early 2011, with all major authorizations targeted for completion by the end of 2012.

Credit Facility Renewal

On January 14, 2011 APUC announced that it has received commitments with a syndicate of banks for a new Algonquin Power Co. $142 million senior secured revolving credit Facility (“Facility”) with a three year term. The Facility syndicate is being led by National Bank of Canada. The other syndicate members are The Toronto-Dominion Bank, Bank of Montreal, and Canadian Imperial Bank of Commerce.

Liberty Water Senior Debt Financing

On December 22, 2010 Liberty Water entered into a U.S. $50 million private placement debt financing. The notes are senior unsecured with a 10 year term bearing interest at 5.6%. The notes are interest only until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. The funds were used to reduce outstanding indebtedness under APCo’s senior credit Facility.

2010 Annual results from operations

Key Selected Annual Financial Information

	Year ended December 31 2010	2009	2008
Revenue	**$182,882**	$ 187,265	$213,796
Adjusted EBITDA [2]	**$ 75,107**	$ 79,368	90,028
Cash provided by Operating Activities	**45,180**	48,031	77,223
Net earnings	**19,639**	31,257	(19,038)
Adjusted net earnings [3]	**19,915**	30,503	18,788
Dividend/distributions to Shareholders/Unitholders [1]	**22,765**	19,322	57,755
Per share/trust unit			
Net earnings	**$ 0.21**	$ 0.39	(0.25)
Adjusted net earnings [3]	**$ 0.21**	$ 0.38	0.25
Diluted net earnings	**$ 0.21**	$ 0.39	(0.25)
Cash provided by Operating Activities	**$ 0.48**	$ 0.60	1.03
Dividends/distributions to Shareholders/Unitholders	**$ 0.24**	$ 0.24	0.75
Total Assets	**980,917**	1,013,413	978,515
Long Term Debt[4]	**257,429**	241,412	293,590

1 Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into APCo trust units.

2 APUC uses Adjusted EBITDA to enhance assessment and understanding of the operating performance of APUC without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted EBITDA is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

3 APUC uses Adjusted net earnings to enhance assessment and understanding of the performance of APUC without the effects of gains or losses on derivative financial instruments which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted net earnings is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

4 Includes the Airsource Senior Debt Financing which matures on October 31, 2011 and has been recorded as a current liability on the consolidated balance sheet.

For the year ended December 31, 2010, APUC reported total revenue of $182.9 million as compared to $187.3 million during the same period in 2009, a decrease of $4.4 million or 2.3%. The major factors resulting in the decrease in APUC revenue in the year ended December 31, 2010 as compared to the corresponding period in 2009, are set out as follows:

	Year ended December 31, 2010
Comparative Prior Period Revenue	$ 187,265
Significant Changes:	
Impact of the stronger Canadian dollar	(10,100)
Impact of shutdown at Energy-from-Waste facility	(5,300)
Effect of hydrology compared to prior year	(4,800)
Change in operating model at Windsor Locks	(3,800)
Closure of land fill gas facilities	(1,100)
Acquisition of Tinker Hydro in Q1 2010	17,800
Red Lily I – development, construction and supervision fees	2,100
Liberty Water revenue increases primarily due to rate case approvals	2,800
All Other	(1,983)
Current Period Revenue	$ 182,882

A more detailed discussion of these factors is presented within the business unit analysis.

For the year ended December 31, 2010, APUC experienced an average U.S. exchange rate of approximately $1.030 as compared to $1.142 in the same period in 2009. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the year ended December 31, 2010 totalled $75.1 million as compared to $79.4 million during the same period in 2009, a decrease of $4.3 million or 5.4%. The decrease in Adjusted EBITDA is in part due to lower earnings from operations primarily resulting from lower average hydrology and wind resources in the Renewable Energy division and the impact of the outage at the Energy-From-Waste ("EFW") facility, partially offset by the acquisition of 36.8 MW of electrical generating assets located in New Brunswick and Maine (the "Tinker Assets") and the completion of various rate case proceedings in Liberty Water as compared to the same period in 2009. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2010, net earnings totalled $19.6 million as compared to $31.3 million during the same period in 2009, a decrease of $11.6 million or 37.2%. Net earnings per share totalled $0.21 for the year ended December 31, 2010, as compared to net earnings per trust unit of $0.39 during the same period in 2009.

Net earnings for the year ended December 31, 2010 decreased by $4.2 million due to increased interest expense, $1.4 million in reduced interest dividend and other income primarily due to gains on the sale of excess land earned in 2009, $0.8 million due to lower earnings from operating facilities, $0.7 million due to lower non-cash gains on U.S. denominated liabilities resulting from the stronger Canadian dollar and $3.3 million due to increased management and administration expense as compared to the same period in 2009. These items were partially offset by an increase of $4.0 million related to lower write downs of property plant and equipment and note receivables, $1.8 million related to increased recoveries of future income tax expense primarily due to the reasons discussed in *Annual Corporate and Other Expenses – Income Taxes,* $2.3 million resulting from reduced minority interest expense at the St. Leon facility primarily due to the lower wind resource experienced in the year ended December 31, 2010 as compared to the same period in 2009. In the comparable period, APUC incurred expenses of $4.7 million related to management internalization and $3.5 million related to corporatization expenses which were not incurred in the current period.

The decrease in net earnings was impacted by a change in unrealized mark-to-market gains on derivative financial instruments which reduced earnings by $16.0 million in the year ended December 31, 2010 as compared to 2009, as a result of changes in the forward interest rate curve and the stronger Canadian dollar, in addition to an expense increase of $2.5 million related to realized losses on derivative financial instruments contracts settled in the period. A more detailed analysis of realized and unrealized mark-to-market gains and losses on foreign exchange contracts and interest swap contracts can be found later in this report under *Treasury Risk Management - Foreign currency risk*.

During the year ended December 31, 2010, cash provided by operating activities totalled $45.2 million or $0.48 per share as compared to cash provided by operating activities of $48.0 million, or $0.60 per share during the same period in 2009. Cash provided by operating activities exceeded dividends declared by 2.0 times during the year ended December 31, 2010 as compared to 2.5 times dividends/distributions declared during the same period in 2009. The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2010 is primarily due to increased realized losses from derivative instruments, increased interest expense and decreased cash flow from operating facilities as compared to the same period in 2009.

2010 Fourth quarter results from operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31 2010	Three months ended December 31 2009
Revenue	**$ 48,874**	$ 43,441
Adjusted EBITDA [2]	**$ 20,693**	$ 18,027
Cash provided by Operating Activities	**18,299**	11,894
Net earnings	**16,888**	(1,366)
Adjusted net earnings[3]	**18,034**	11,504
Dividend/distributions to Shareholders/Unitholders [1]	**5,725**	4,998
Per share/trust unit		
Net earnings	**$ 0.18**	$ (0.03)
Adjusted net earnings[3]	**$ 0.19**	$ 0.14
Diluted net earnings	**$ 0.18**	$ (0.03)
Cash provided by Operating Activities	**$ 0.19**	$ 0.15
Dividends/distributions to Shareholders/Unitholders	**$ 0.06**	$ 0.06
Total Assets	**980,917**	1,013,413
Long Term Debt[4]	**257,429**	241,421

1 Includes dividends/distributions to APUC shareholders/unitholders and Airsource units exchangeable into APCo trust units.

2 APUC uses Adjusted EBITDA to enhance assessment and understanding of the operating performance of APUC without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted EBITDA is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

3 APUC uses Adjusted net earnings to enhance assessment and understanding of the performance of APUC without the effects of gains or losses on derivative financial instruments which are derived from a number of non-operating factors, accounting methods and assumptions. Adjusted net earnings is a non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

4 Includes the Airsource Senior Debt Financing which matures on October 31, 2011 and has been recorded as a current liability on the consolidated balance sheet.

For the three months ended December 31, 2010, APUC reported total revenue of $48.9 million as compared to $43.4 million during the same period in 2009, an increase of $5.4 million or 12.5%. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2010 as compared to the corresponding period in 2009 are set out as follows:

	Three months ended December 31, 2010
Comparative Prior Period Revenue	$ 43,441
Significant Changes:	
Acquisition of Tinker Hydro in Q1 2010	4,200
Liberty Water revenue increases primarily due to rate case approvals	1,400
Impact of shutdown at Energy-from-Waste facility	600
Effect of wind resource compared to prior year	600
Red Lily I – development, construction and supervision fees	600
Effect of hydrology compared to prior year	500
Change in operating model at Windsor Locks	(800)
Impact of the stronger Canadian dollar	(900)
Other	(767)
Current Period Revenue	$ 48,874

A more detailed discussion of these factors is presented within the business unit analysis.

For the three months ended December 31, 2010, APUC experienced an average U.S. exchange rate of approximately $1.032 as compared to $1.057 in the same period in 2009. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended December 31, 2010 totalled $20.7 million as compared to $18.0 million during the same period in 2009, an increase of $2.7 million or 14.8%. The increase in Adjusted EBITDA is in part due to increased earnings from operations primarily resulting from the acquisition of the Tinker Assets and increased revenues from Liberty Water resulting from the completion of rate cases, partially offset by lower average hydrology in the Renewable Energy division and the impact of the stronger Canadian dollar as compared to the same period in 2009. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2010, net earnings totalled $16.9 million as compared to net loss of $1.4 million during the same period in 2009, an increase of $18.3 million. Net earnings per share totalled $0.18 for the three months ended December 31, 2010, as compared to net loss per share of $0.03 during the same period in 2009.

Net earnings for the three months ended December 31, 2010 increased by $5.4 million due to increased earnings from operating facilities, $4.9 million related to increased recoveries of income tax expense primarily due to the reasons discussed in *Annual Corporate and Other Expenses – Income Taxes*, and $4.0 million related to lower write downs of property plant and equipment and note receivables, as compared to the same period in 2009. These items were partially offset by increased expenses of $2.4 million due to increased management and administration expense, $1.1 million due to increased interest expense, $0.6 million due to increased amortization expense and $0.2 million due to lower non-cash gains on U.S. denominated liabilities resulting from the stronger Canadian dollar as compared to the same period in 2009. In the comparable period, APUC incurred expenses of $4.7 million related to management internalization, $3.5 related to corporatization expenses which were not incurred in the current period.

The change in unrealized mark-to-market losses/(gains) on derivative financial instruments resulting from changes in foreign exchange rates relate to contract periods which extend to fiscal 2013. Unrealized mark-to-market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. A more detailed analysis of realized and unrealized mark to market gains and losses on foreign exchange contracts and interest swap contracts can be found later in this report under *Treasury Risk Management - Foreign currency risk*.

During the three months ended December 31, 2010, cash provided by operating activities totalled $18.3 million or $0.19 per share as compared to cash provided by operating activities of $11.9 million, or $0.15 per trust unit during the same period in 2009. Cash provided by operating activities exceeded dividends declared by 3.2 times during the quarter ended December 31, 2010 as compared to 2.4 times distributions during the same period in 2009. The change in cash provided by operating activities after changes in working capital in the three months ended December 31, 2010, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2009.

Outlook

APCo

The APCo Renewable Energy division is expected to perform at long-term average resource conditions for hydrology and below average wind resources in the first quarter of 2011.

APCo's load supply and energy procurement contracts in northern Maine and the Independent System Operator New England ("ISO-NE") market (the "Energy Services Business") anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 30,000 MW-hrs of energy to its customers in the first quarter of 2011 and, based on long term average hydrology for this period, the Tinker Assets are anticipated to provide 40% of the energy required to service this load. Subsequent to December 31, 2010, the Energy Services Business entered into a three year contract with Maine Public Service Company, a regulated electric transmission and distribution utility serving approximately 36,000 electricity customer accounts in Northern Maine ("MPS") starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with the standard offer service is approximately 135,000 MW-hrs.

The capital upgrade at the EFW facility, completed in July 2010, is expected to result in higher throughput and lower operating costs at the facility in the first quarter of 2011 as compared to the same period in 2010 when the facility was temporarily shut down as a result of an unplanned outage experienced in January 2010. APCo Thermal Energy division's Sanger facility should meet APCo's expectations for the first quarter of 2011 and be in line with 2010 results. Hydro-mulch sales are expected to be similar to 2010 sales due to continuing low demand for hydro-mulch in the U.S.

APCo Thermal Energy division's Windsor Locks facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO-NE day-ahead market or to retail customers through the Energy Services Business. The facility did not commit any portion of its electrical capacity to the forward reserve market ("FRM") for the winter of 2011 due to unacceptably low auction prices. It is anticipated that performance during the first quarter of 2011 will be strong, resulting from moderate natural gas prices and a cold winter in the north-east U.S. that has resulted in high electricity prices. APCo has completed preliminary engineering for a repowering project at the Windsor Locks facility and is in negotiations with Ahlstrom regarding this project. For a more detailed description of the options and expected impact see *Development Division - Windsor Locks*.

Liberty Water

Liberty Water is forecasting modest customer growth in 2011 with the continuing economic recovery in the United States. Liberty Water provides water distribution and wastewater collection and treatment services, primarily in the southern and southwestern U.S. where communities have traditionally experienced long term growth and that provide continuing future opportunities for organic growth.

On December 11, 2011, the Arizona Corporate Commission ("ACC") approved an order authorizing a rate increase of U.S. $0.9 million for Rio Rico Utilities Inc., effective February 1, 2011. It is anticipated that the regulatory review of the proposed rates and tariffs for the Bella Vista, Northern Sunrise, and Southern Sunrise facilities will be completed in Q1 2011. Total revenue increases from rate cases completed in Arizona and Texas represent an additional U.S. $10.2 million in annualized revenue. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year.

Liberty Energy

In 2009, APUC announced plans to acquire the California Utility assets in partnership with Emera. The acquisition was approved by both the California Public Utilities Commission ("CPUC") and the Public Utilities Commission of Nevada in the fourth quarter of 2010. Subsequent to these approvals, the transaction was completed on January 1, 2011 for a purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. The acquisition was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility. Liberty Energy's ownership share of the cost of acquisition of the California Utility was primarily funded through the proceeds of subscription receipts held by Emera for 8.532 million APUC common shares at a price of $3.25 per share.

On December 9, 2010, Liberty Energy entered into agreements to acquire all issued and outstanding shares of Granite State and EnergyNorth from National Grid for total consideration of U.S. $285.0 million.

Liberty Energy is pursuing additional investments in electric distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best in-class-customer care for its subsidiary utility ratepayers.

APCo: Renewable Energy

	Three months ended December 31			Twelve months ended December 31		
	Long Term Average Resource	2010	2009	Long Term Average Resource	2010	2009
Performance (MW-hrs sold)						
Quebec Region	**72,575**	**84,125**	73,650	**276,825**	**275,850**	299,900
Ontario Region	**34,750**	**20,200**	30,350	**144,725**	**90,225**	134,800
Manitoba Region	**105,000**	**97,150**	89,625	**372,000**	**343,100**	364,500
New England Region	**15,425**	**13,380**	16,200	**65,275**	**47,900**	81,725
New York Region	**24,100**	**24,375**	24,750	**91,100**	**79,550**	95,000
Western Region	**13,400**	**10,450**	10,875	**67,250**	**59,100**	58,200
Maritime Region	**39,575**	**55,525**	2,425	**148,250**	**148,550**	7,025
Total	**304,825**	**305,205**	247,875	**1,165,425**	**1,044,275**	1,041,150
Revenue						
Energy sales		**$ 21,867**	$ 16,604		**$ 80,117**	$ 68,227
Less:						
Cost of Sales – Energy*		**(431)**	—		**(5,047)**	—
Net Energy Sales		**$ 21,436**	$ 16,604		**$ 75,070**	$ 68,227
Other Revenue		**563**	—		**2,122**	—
Total Net Revenue		**$ 21,999**	**$ 16,604**		**$ 77,192**	**$ 68,227**
Expenses						
Operating expenses		**(7,013)**	(6,619)		**(24,434)**	(22,279)
Interest and Other income		**151**	433		**783**	1,226
Division operating profit (including other income)		**$ 15,137**	$ 10,418		**$ 53,541**	$ 47,174

* Cost of Sales – Energy consists of energy purchases by the Energy Services Business, where this energy is sold to customers pursuant to fixed rate energy contracts.

As APCo's hydroelectric generating facilities in the New York and New England regions primarily sell their output at market rates, the average revenue earned per MW-hr sold can vary significantly from the same period in the prior period or year. APCo's hydroelectric generating facilities in the Maritime region primarily sell their output to the Energy Services Business which, in turn, sells this energy at fixed price contracts to local electric utilities and commercial buyers in Northern Maine. APCo's facilities in the other regions are subject to varying rates, by facility, as set out in each facility's individual PPA. As such, while most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

2010 Annual Operating Results

For the twelve months ended December 31, 2010 the Renewable Energy division produced 1,044,275 MW-hrs of electricity, as compared to 1,041,150 MW-hrs produced in the same period in 2009, an increase of 0.3%. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 58,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 575,000 tons of CO_2 gas was prevented from entering the atmosphere in 2010.

For the year ended December 31, 2010, the division generated electricity equal to 90% of long-term projected average resources (wind and hydrology) as compared to 102% during the same period in 2009. Over 2010, the Maritime and Quebec regions experienced resources generally consistent with long-term averages. The Manitoba, New York and Western regions experienced resources within 15% of long-term averages. The Ontario region experienced resources approximately 40% below long-term averages and the New England region experienced resources approximately 25% below long-term averages. The lower wind resource in the Manitoba region in the first quarter and fourth quarters of 2010 was similar to lower wind resources experienced at other wind farms in North America.

For the year ended December 31, 2010, revenue from energy sales in the Renewable Energy division totalled $80.1 million, as compared to $68.2 million during the same period in 2009, an increase of $11.9 million or 17.4%. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the year ended December 31, 2010, net revenue from energy sales in the Renewable Energy division totalled $75.1 million, as compared to $68.2 million during the same period in 2009, an increase of $6.8 million or 10.0%.

Revenue from APCo's New England and New York region facilities increased $0.8 million due to an increase in weighted average energy rates of approximately 15.8% and decreased $2.4 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba region increased $1.0 million due to an increase in weighted average energy rates of approximately 5.9%, offset by a decrease of $1.2 million due to a weaker wind resource, as compared to the same period in 2009. The power purchase agreement associated with the St. Leon facility requires the facility to generate a minimum amount of dependable energy during the annual contract year ending April 30. Energy generated above the dependable amount earns revenue at lower, non-dependable rates. As a result of the lower production experienced in the first quarter of 2010, during the annual contract year ending April 30, 2010, the facility earned revenue primarily at the dependable rates as compared to the same period in 2009 when a greater proportion of revenue was earned at the non-dependable rates. Revenue generated by the Ontario, Quebec and Western regions increased by $1.9 million due to an increase in weighted average energy rates of approximately 6.3%, primarily the result of increased rates at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The increases in revenue at APCo's Ontario, Quebec and Western regions were offset by a decrease of $4.8 million due to lower energy production, primarily the result of lower production from reduced hydrologic resources available at the Long Sault facility in the Ontario region, as compared to the same period in 2009. The Maritime region, in conjunction with the Energy Services Business, generated $17.7 million in revenue, before energy purchases. This revenue arose from electricity sales under sales agreements with local electric utilities and wholesale consumers in Northern Maine ($14.0 million) and New Brunswick ($1.9 million) and merchant sales of production in excess of customer demand ($1.7 million).

Other revenue for the year ended December 31, 2010 totalled $2.1 million, as compared to nil during the same period in 2009. Other revenue represents amounts earned related to the development and construction of the Red Lily I wind project.

The division reported decreased revenue of $0.6 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the year ended December 31, 2010, energy purchase costs of the Energy Services Business totalled U.S. $4.9 million. In 2010, the Energy Services Business purchased approximately 74,900 MW-hrs of energy at market and fixed rates averaging U.S. $65 per MW-hr. The Maritime region generated approximately 65% of the load required to service its customers as well as the Energy Services Business' customers in 2010. The energy purchases represent a combination of the load requirement of the Energy Services Business' customers and the timing of this demand as compared to the energy produced by the Tinker Assets and the timing of this production. The division reported increased energy costs of $0.1 million as a result of the Canadian dollar exchange rates.

For the year ended December 31, 2010, operating expenses excluding energy purchases totalled $24.4 million, as compared to $22.3 million during the same period in 2009, an increase of $2.2 million or 9.7%. Operating expenses were impacted by $1.5 million of increased expenses at the St. Leon facility, primarily resulting from scheduled payments under the extended warranty and operation and maintenance agreement with Vestas, $0.6 million of increased operating expenses at the U.S. hydroelectric facilities, and $2.9 million related to operating costs associated with the Tinker Assets and the Energy Services Business as compared to the same period in 2009. These increases were partially offset by $0.6 million in decreased operating costs at Canadian facilities, primarily due to lower variable operating costs tied to lower revenue and lower repair and maintenance projects commenced in 2010. Operating expenses include costs incurred in the period of $1.1 million associated with the pursuit of various growth and development activities, including operating expenses associated with the construction supervision work on the Red Lily I wind project, as compared to development costs incurred of $2.1 million in the same period in 2009. Operating expenses in 2010 were lower due to a reimbursement of $0.9 million related to costs previously expensed by APUC in connection with the development of the Red Lily I wind project. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the year ended December 31, 2010, Renewable Energy's operating profit totalled $53.5 million, as compared to $47.2 million during the same period of 2009, representing an increase of $6.4 million or 13.5%. Renewable Energy's operating profit did not meet APCo's expectations primarily due to a lower than expected wind resource in the Manitoba region in the first quarter of 2010 and lower hydrology in the second and third quarters of 2010.

2010 Fourth Quarter Operating Results

For the quarter ended December 31, 2010, the Renewable Energy division produced 305,205 MW-hrs of electricity, as compared to 247,875 MW-hrs produced in the same period in 2009, an increase of 23.1%. The increased generation is primarily due to the acquisition of the Tinker Hydro facility in January 2010 and therefore did not form part of the production in the comparable period in 2009. The level of production in 2010 represents sufficient renewable energy to supply the equivalent of 68,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 168,000 tons of CO2 gas was prevented from entering the atmosphere in the fourth quarter of 2010.

During the quarter ended December 31, 2010, the division generated electricity equal to long-term projected average resources (wind and hydrology) as compared to 93% during the same period in 2009. In the fourth quarter of 2010, the Maritimes and Quebec regions experienced resources significantly higher than long-term averages, producing approximately 40% and 15% above long-term average resources, respectively. The New York region experienced resources approximately equal to the long-term average, while the Manitoba and New England regions experienced resources of approximately 10% below long-term averages. The Ontario and Western regions experienced results significantly below long-term average resources.

For the quarter ended December 31, 2010, revenue from energy sales in the Renewable Energy division totalled $21.9 million, as compared to $16.6 million during the same period in 2009, an increase of $5.3 million or 31.7%. As the purchase of energy by the Energy Services Business is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2010, net revenue from energy sales in the Renewable Energy division totalled $21.4 million, as compared to $16.6 million during the same period in 2009, an increase of $4.8 million or 29.1%.

Revenue from APCo's New England and New York region facilities increased $0.2 million due to an increase in weighted average energy rates of approximately 15.5%, offset by $0.3 million due to decreased average hydrology, as compared to the same period in 2009. Revenue from the Manitoba region increased $0.6 million primarily due to a stronger wind resource, as compared to the same period in 2009. Revenue generated by the Ontario, Quebec and Western regions increased by $0.2 million due to an increase in weighted average energy rates of approximately 2.0%, primarily the result of increased rates at the Long Sault facility in the Ontario region, and $0.2 million due to increased energy production, primarily the result of increased production in the Quebec region, as compared to the same period in 2009. The Maritime region, in conjunction with the Energy Services Business, generated $4.2 million in revenue, before energy purchases. This revenue consists of sales to local electric utilities and wholesale consumers in Northern Maine ($2.6 million) and New Brunswick ($0.6 million) and merchant sales of production in excess of customer demand and other revenue ($0.9 million).

Other revenue for the three months ended December 31, 2010 totalled $0.6 million, as compared to nil during the same period in 2009. Other revenue represents amounts earned related to the development and construction of the Red Lily I wind project.

For the quarter ended December 31, 2010, energy purchase costs by the Energy Services Business totalled U.S. $0.4 million. During the quarter, the Energy Services Business purchased approximately 9,500 MW-hrs of energy at market and fixed rates averaging $44 per MW-hr. The Maritime region generated approximately 95% of the load required to service its customers as well as the Energy Services Business' customers in the three months ended December 31, 2010. The energy purchases represent a combination of the load requirement of the Energy Services Business' customers and the timing of this demand as compared to the energy produced by the Tinker Assets and the timing of this production.

For the quarter ended December 31, 2010, operating expenses excluding energy purchases totalled $7.0 million, as compared to $6.6 million during the same period in 2009, an increase of $0.4 million or 6.0%. Operating expenses were impacted by $0.2 million of increased expenses at the St. Leon facility, primarily resulting from scheduled payments under the extended warranty and operation and maintenance agreement with Vestas and $1.0 million related to operating costs associated with the Tinker Assets and the Energy Services Business, as compared to the same period in 2009. These increases were partially offset by $0.4 million in decreased operating costs at Canadian facilities primarily due to lower variable operating costs. Operating expenses include costs incurred in the period of $0.8 million associated with the pursuit of various growth and development activities, including operating expenses associated with the construction supervision work on the Red Lily I wind project as compared to development costs incurred of $0.9 million in the same period in 2009. The division reported decreased expenses of $0.2 million from U.S. operations as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended December 31, 2010, Renewable Energy's operating profit totalled $15.1 million, as compared to $10.4 million during the same period of 2009, representing an increase of $4.7 million or 45.3%. For the quarter ended December 31, 2010, Renewable Energy's operating profit met APCo's expectations primarily due to improved hydrology in the quarter in the Quebec and Maritime regions.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform at long-term average resource conditions for hydrology and below long-term average wind resources in the first quarter of 2011.

The construction phase of the Red Lily I project is now complete with commercial operation occurring under the SaskPower PPA in February 2011. The power purchase agreement with SaskPower is for 25 years and includes a 2% annual increase throughout the term of the agreement. APUC's investment of $19.6 million in the Red Lily I facility has been initially structured as senior and subordinated debt bearing a blended interest rate of 8.43%. The balance of the total expected project construction costs of $71.2 million have been financed by senior debt from third party lenders in the amount of $31.0 million and an equity contribution from an independent investor estimated to be $20.6 million. In addition to interest payments on its debt financing, APUC is entitled to certain supervisory fees, estimated at $1.3 million in the first full year of operation. Total interest and fee payments in 2011 are estimated to be approximately $2.4 million representing approximately 75% of net cash flows from the facility. APUC has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest, exercisable in February 2016.

The Energy Services Business anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 30,000 MW-hrs of energy to its customers in the first quarter of 2011. Based on historical long term average levels of hydroelectric energy generation for the first quarter of 2011, the Tinker Assets are anticipated to provide 40% of the energy required by the Energy Services Business to service its customers which provides a natural hedge on supply costs of the Energy Services Business. In respect of each customer delivery obligation, the Energy Services Business has in place fixed price financial energy contracts to operationally hedge the price of the customer supply obligation and to minimize the volatility of the energy price. These contracts in combination with the expected Tinker production are used to balance the monthly customer load.

Subsequent to December 31, 2010, the Energy Services Business entered into a three year contract with MPS starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with this bid is approximately 135,000 MW-hrs.

As a result of certain legislation passed in Quebec (Bill C93), APCo's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. As a result of the assessments and a preliminary evaluation of the associated remedial work, APCo currently estimates capital expenditures of approximately $17.1 million related to compliance with the legislation. The timing of when the actual capital costs need to be made is determined as part of the technical assessments.

APCo anticipates that these expenditures will be invested over a period of several years approximately as follows:

	Total	2011	2012	2013	2014	2015
Estimated Bill C-93 Capital Expenditures	17,100	800	5,000	5,500	3,000	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities. APCo does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. APCo continues to explore several alternatives to mitigate the capital costs of the modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

APCo: Thermal Energy Division

	Three months ended December 31		Twelve months ended December 31	
	2010	2009	**2010**	2009
Performance (MW-hrs sold)	**120,600**	147,482	**465,390**	571,505
Performance (tonnes of waste processed)	**43,535**	42,189	**90,690**	161,102
Revenue				
Energy sales	**$ 12,185**	$ 13,819	**$ 52,609**	$ 62,209
Less:				
Cost of Sales – Fuel *	**(5,492)**	(5,224)	**(22,348)**	(26,517)
Net Energy Sales Revenue	**$ 6,693**	$ 8,595	**$ 30,261**	$ 35,692
Waste disposal sales	**4,164**	3,786	**9,039**	14,468
Other revenue	**311**	545	**1,209**	3,848
Total net revenue	**$ 11,168**	$ 12,926	**$ 40,509**	$ 54,008
Expenses				
Operating expenses *	**(6,127)**	(7,121)	**(23,948)**	(30,782)
Interest and other income	**100**	140	**495**	821
Division operating profit (including interest and dividend income)	**$ 5,141**	$ 5,945	**$ 17,056**	$ 24,047

* Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities.

APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and in different regional hubs. As a result, the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other showing decreasing costs, as compared to the same period in the prior year. *'Cost of Sales – Fuel'* is calculated as the volume of natural gas consumed by a facility times the average landed cost of natural gas. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed cost for natural gas combined with a consumption of a higher volume of natural gas.

2010 Annual Operating Results

In 2010, the EFW facility processed 90,690 tonnes of municipal solid waste as compared to 161,102 tonnes processed in the same period of 2009, a decrease of 43.7%. The significantly reduced throughput was a result of the unplanned outage experienced in January 2010 which resulted in the facility being temporarily shut down. The major capital upgrades to the facility were completed at the end of the second quarter and the facility was restarted on July 14, 2010. The status of this facility is discussed in further detail in *Divisional Outlook – Thermal Energy*, below. This level of production resulted in the diversion of approximately 65,000 tonnes of waste from landfill sites in 2010.

For the year ended December 31, 2010, the Thermal Energy Division produced 465,390 MW-hrs of energy as compared to 571,505 MW-hrs of energy in the comparable period of 2009. During the year ended December 31, 2010, the business unit's performance decreased by 83,800 MW-hrs at the Windsor Locks facility, 23,000 MW-hrs at the land-fill gas ("LFG") facilities and 3,500 MW-hrs from EFW's steam turbine, partially offset by an increase of 3,900 MW-hrs at the Sanger facility, as compared to the same period in 2009.

The decrease in electrical generation at the Windsor Locks facility was the expected result of the expiry of the PPA with Connecticut Light & Power in April 2010 and the change in operating model for the facility to one where revenues are earned from payments under the continuing energy sales agreement with the co-located electricity and thermal energy host augmented by capacity and energy payments from the ISO-NE and associated markets. As a result, the facility will only generate additional energy beyond that needed to service the existing industrial customer when market conditions warrant, resulting in reduced energy production compared to the historic operating model. The decrease in electrical generation at the EFW facility was the result of the unplanned outage which occurred in January 2010.

For the year ended December 31, 2010, APCo ceased generating energy at the LFG facilities, initiated a process to close these facilities and sold the generating assets. See *APUC Annual Corporate and other Expenses* for additional details related to the write down in the carrying value of these assets.

For the year ended December 31, 2010, revenue in the Thermal Energy division totalled $62.9 million, as compared to $80.5 million during the same period in 2009, a decrease of $17.7 million or 21.9%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. During the year ended December 31, 2010, net energy sales revenue at the Thermal Energy division totalled $30.3 million, as compared to $35.7 million during the same period in 2009, a decrease of $5.4 million or 15.2%.

For the year ended December 31, 2010, energy sales revenue in the Thermal Energy division totalled $52.6 million, as compared to $62.2 million during the same period in 2009, a decrease of $9.6 million or 15.4%. The decrease in revenue from energy sales was primarily due to a decrease of $6.7 million at the Windsor Locks facility as a result of decreased production, partially offset by an increase of $3.0 million as a result of increased energy rates, in part due to a higher average landed price per mmbtu for natural gas and the change in operating model of the facility and a decrease of $1.3 million as a result of the closure of the LFG facilities, as compared to the same period in 2009. The decreases were partially offset by an increase in revenue from energy sales $0.4 million at the Sanger facility as a result of increased energy rates, in part due to higher average landed price per mmbtu for natural gas and $0.5 million at the Sanger facility as a result of increased production, as compared to the same period in 2009. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $5.4 million from operations as a result of the stronger Canadian dollar, as compared to the same period in 2009.

Revenue from waste disposal sales in 2010 totalled $9.0 million, as compared to $14.5 million during the same period in 2009, a decrease of $5.4 million or 37.6%. The EFW facility generated lower revenue in the period as it was temporarily shut down between January and July 2010 as a result of the unplanned outage.

Other revenue for the year ended December 31, 2010 totalled $1.2 million, as compared to $3.8 million during the same period in 2009, a decrease of $2.6 million or 68.6%. The decrease in other revenue was primarily due to a decrease of $1.6 million at the hydro-mulch facility due to reduced customer demand. In the comparable period in 2009, other revenue included $0.6 million from APCo's LFG facilities which were not operational in the current period. The division reported decreased other revenue of $0.5 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the year ended December 31, 2010, fuel costs at Sanger and Windsor Locks totalled U.S. $21.7 million, as compared to U.S. $23.0 million during the same period in 2009, a decrease of U.S. $1.3 million. The overall natural gas expense at the Windsor Locks facility decreased $1.8 million (10%), primarily the result of a 14% reduction in volume of natural gas consumed, partially offset by a 5% increase in the average landed cost of natural gas per mmbtu, as compared to the same period in 2009. The average landed cost of natural gas at the Windsor Locks facility was U.S. $4.84 per mmbtu. The reduction in natural gas expense was partially offset by an increase in the overall natural gas expense at Sanger of $0.5 million (12%), primarily the result of an 11% increase in the average landed cost of natural gas per mmbtu. The average landed cost of natural gas at the Sanger facility was U.S. $4.79 per mmbtu. The division reported decreased fuel costs of $2.9 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the year ended December 31, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $23.9 million, as compared to $30.8 million during the same period in 2009, a decrease of $6.8 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of

$5.1 million at the EFW facility resulting from the outage at the facility, reduced material costs of $0.9 million at the hydro-mulch facility resulting from lower production, and $1.7 million of lower costs due to the closing of the LFG facilities partially offset by increased natural gas expense of $1.3 million at the Brampton Cogeneration Inc. ("BCI") facility as a result of decreased steam production at EFW and increased steam production from BCI's auxiliary boiler as compared to the same period in 2009. Operating expenses included costs of $0.5 million associated with the pursuit of various growth and development activities, as compared to nil in the same period in 2009. The division reported decreased operating expenses of $1.4 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

Interest and other income for the year ended December 31, 2010 totalled $0.5 million, as compared to $0.8 million in the same period in 2009. During the year ended December 31, 2010, APUC determined that earnings from equity investments should be presented at the corporate level rather than at a divisional level. As a result, the comparable figures have been reclassified to conform to the presentation adopted in the current year.

For the year ended December 31, 2010, the Thermal Energy division's operating profit totalled $17.1 million, as compared to $24.0 million during the same period in 2009, representing a decrease of $7.0 million or 29%. Operating profit in the Thermal Energy division did not meet overall expectations for the year ended December 31, 2010, primarily due to the unplanned outage at the EFW facility, the change in operating model at Windsor Locks and lower demand for hydro-mulch resulting from the current economic slow down in the U.S.

2010 Fourth Quarter Operating Results

During the quarter ended December 31, 2010, the EFW facility processed 43,535 tonnes of municipal solid waste as compared to 42,189 tonnes processed in the same period of 2009, an increase of 3.2%. This level of production resulted in the diversion of approximately 32,000 tonnes of waste from municipal solid waste landfill sites in 2010.

During the quarter ended December 31, 2010, the business unit produced 120,600 MW-hrs of energy as compared to 147,482 MW-hrs of energy in the comparable period of 2009. During the quarter ended December 31, 2010, the business unit's performance decreased by 25,300 MW-hrs at the Windsor Locks facility and 5,600 MW-hrs at the LFG facilities, partially offset by an increase of 3,000 MW-hrs at the Sanger facility and 1,000 MW-hrs at the EFW facility, as compared to the same period in 2009. See the discussion of the annual operating results regarding the decrease in electrical generation at the Windsor Locks facility.

During the quarter ended December 31, 2010, APCo sold the generating assets at the LFG facilities. See *APUC Annual Corporate and other Expenses* for additional details related to the write-down in the carrying value of these assets.

For the quarter ended December 31, 2010, revenue in the Thermal Energy division totalled $16.7 million, as compared to $18.2 million during the same period in 2009, a decrease of $1.5 million, or 8.2%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended December 31, 2010, net energy sales revenue at the Thermal Energy division totalled $6.7 million, as compared to $8.6 million during the same period in 2009, a decrease of $1.9 million.

For the quarter ended December 31, 2010, energy sales revenue in the Thermal Energy division totalled $12.2 million, as compared to $13.8 million during the same period in 2009, a decrease of $1.6 million or 11.8%. The decrease in revenue from energy sales was primarily due to a decrease of $1.8 million at the Windsor Locks facility as a result of decreased production, partially offset by an increase of $1.0 million as a result of increased energy rates, in part due to a higher average landed price per mmbtu for natural gas and the change in operating model of the facility and a decrease of $0.3 million as a result of the closure of the LFG facilities, as compared to the same period in 2009. The decrease in revenue was partially offset by $0.1 million at the BCI facility as a result of increased price for steam, as compared to the same period in 2009. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $0.4 million from operations as a result of the stronger Canadian dollar, as compared to the same period in 2009.

Revenue from waste disposal sales for the quarter ended December 31, 2010 totalled $4.2 million, as compared to $3.8 million during the same period in 2009. The increase was a result of the EFW facility processing a higher throughput of municipal solid waste as compared to the same period in 2009.

Other revenue for the quarter ended December 31, 2010 totalled $0.3 million, as compared to $0.5 million during the same period in 2009. The decrease in other revenue was due to decreased revenue at the hydro-mulch facility due to reduced customer demand in the quarter.

For the quarter ended December 31, 2010, fuel costs at Sanger and Windsor Locks totalled U.S $5.4 million, as compared with U.S $4.9 million in the same period in 2009, an increase of U.S. $0.5 million. The overall natural gas expense at the Windsor Locks facility increased $0.5 million (14%), primarily the result a 45% increase in the average landed cost of natural gas per mmbtu, partially offset by a 21% reduction in volume of natural gas consumed, as compared to the same period in 2009. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $5.00 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of $0.1 million (4%), primarily the result of a 10% decrease in the average landed cost of natural gas per mmbtu, partially offset by a 7% increase in the volume of natural gas consumed as compared to the same period in 2009. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.40 per mmbtu. The division reported decreased fuel costs of $0.2 million as a result of the stronger Canadian dollar as compared to the same period in 2009.

For the quarter ended December 31, 2010, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $6.1 million, as compared to $7.1 million during the same period in 2009, a decrease of $1.0 million. The decrease in operating expenses for the quarter was primarily due to reduced material costs of $0.2 million at the hydro-mulch facility resulting from lower production, $0.1 million of reduced operating costs at BCI and $0.8 million of reduced operating costs at the LFG facilities partially offset by $0.3 million in increased operating costs at the Windsor Locks facility as compared to the same period in 2009.

Interest and other income for the three months ended December 31, 2010 totalled $0.1 million, consistent with the same period in 2009.

For the quarter ended December 31, 2010, the Thermal Energy division’s operating profit totalled $5.1 million, as compared to $5.9 million during the same period in 2009, representing a decrease of $0.8 million or 13.5%. Operating profit in the Thermal Energy division did not meet overall expectations for the quarter ended December 31, 2010, primarily due to lower than expected earnings at the Windsor Locks facility as a result of decreased production volume.

Divisional Outlook – Thermal Energy

The capital upgrade completed at the EFW facility is expected to result in higher throughput and lower operating costs at the facility which should positively affect operating profit generated by the facility in 2011 as compared to the same period in 2010 when the facility was temporarily shut down as a result of an unplanned outage experienced in January 2010. APCo Thermal Energy division’s Sanger facility should meet APCo’s expectations for the first quarter of 2011 and be in line with 2010 results. Hydro-mulch sales are expected to be similar to 2010 sales due to continuing low demand for hydro-mulch in the U.S.

APCo Thermal Energy division’s Windsor Locks facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO-NE day-ahead market or to industrial customers through the Energy Services Business. The facility did not commit any portion of its remaining capacity to the FRM for the winter of 2011 due to unacceptably low auction prices. It is anticipated that performance during the first quarter of 2011 will be strong, resulting from moderate gas prices and a cold winter in the north-east U.S. that have resulted in high electricity prices.

Algonquin has completed preliminary engineering for a repowering project at the Windsor Locks facility and is in negotiations with the steam host regarding this project. See *APCo Development Division – Windsor Locks* for further discussion on the potential repowering project.

APCo: Development Division

The Development division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. The Development division is led by six full time employees who have access to, and support from, all of APCo's available resources to assist it in the development of projects. Typically, the division draws upon the support of the finance, engineering, technical services, and environmental and regulatory compliance groups. It also utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The Development division believes that the prevailing economic climate has also created opportunities for APCo to acquire third party development projects on terms that require the experience and financial resources that APCo has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

Industry Outlook

Environmental concerns, increases in electricity demand and fossil fuel price volatility have combined to create the impetus for governments, regulatory bodies and utilities to diversify their mix of power generation. This diversification has largely been focused on developing a larger proportion of renewable power and high-efficiency gas generation. Consequently, a favourable policy environment has emerged for independent producers and developers of renewable and thermal power generation, particularly in the areas of wind, hydroelectric and natural gas generation. Additionally, there has been a general recognition that energy produced by independent producers which is priced in the context of market competition offer a lower cost means of production to utilities.

An increasing amount of attention has been paid to the environmental value of both renewable and efficient means of power production and the ability of the power industry to offset the ill-effects of production by higher polluting fossil fuels. To the extent that a renewable or efficient source of energy can offset a fossil fuelled generating source, it can, in some cases, generate a carbon credit which can then be sold to a third party. Despite the fact that there is no nationally recognized carbon reduction program in either the U.S. or Canada, there remain several regional organizations that have been established with targets to reduce carbon emissions. Globally, the value of the carbon market doubled for three consecutive years from U.S. $31.2 billion in 2006 to U.S. $138.9 billion in 2009. This should enhance the ability to develop future renewable sources of generation.

Divisional Outlook - Development

It is anticipated that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the U.S., continue to increase targets for renewable and other clean power generation projects. In May 2009, the Ontario government passed the Green Energy Act ("GEA"). Accordingly the OPA has issued standard pricing for electricity from renewable sources under a FIT program. Included within this legislation is the requirement for OPA to purchase power generated from green energy projects, and an obligation for all utilities to grant priority grid access to such projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.

Other jurisdictions have passed similar legislation. British Columbia has announced the Clean Energy Act and Nova Scotia is pursuing the 2010 Renewable Electricity Plan and will be establishing pricing for its ensuing Community FIT program in April of 2011. Both of these proposed pieces of legislation have set aggressive targets for the development of new, renewable power production. They also introduce the concept of fixed pricing based on a FIT for some categories of new renewable power projects. The combination of increased renewable production targets and appropriate fixed pricing will present investment opportunities for APCo to consider in the future.

Current Development Projects

Amherst Island

On February 25, 2011, APUC announced that the OPA has awarded a FIT contract to the wholly-owned 75 MW Amherst Island Wind Project, located on Amherst Island in the village of Stella, approximately 25 kilometers southwest of Kingston, Ontario. The contract has been awarded as part of the second round of the OPA's FIT program.

The project, which will be developed by APCo, is currently contemplated to use more efficient Class III wind turbine generator technology. While final turbine selection remains to be made, modelling the higher energy capture ratios of turbines, such as the Vestas V100 or Repower MM100, forecast that the available wind resource would produce approximately 247 GW hrs of power annually. Funding for the total capital costs currently estimated to be $220 million will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 months.

Quebec Community Wind Projects

In July 2010, APCo worked with Société en Commandite Val-Eo, a cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded contracts that stipulate the use of ENERCON turbines.

The quantum of the interests of APUC in the Saint-Damase and Val- Éo projects is subject to final negotiations with the partners in the projects but, in any event, will not be less than 50% and 25%, respectively. Final funding of the projects will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting will begin for both projects in early 2011, with all major authorizations targeted for completion by the end of 2012.

St. Damase

The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APUC. The first 24 MW phase of the project is currently envisioned to consist of twelve 2MW ENERCON E-82 wind turbine generators, producing approximately 86,000 MW-hrs annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

Val Eo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APUC. The first 24 MW phase of the project is expected to be comprised of eight 3MW ENERCON E-101 wind turbine generators, producing approximately 66,000 MW-hrs annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

Red Lily II

In addition to the now completed Red Lily I project, APCo has secured additional land options related to property around Red Lily I to facilitate a 106 MW expansion ("Red Lily II"). The viability of the expanded project will be conditional upon a review of the actual operating results from Red Lily I. During the first quarter of 2010, APCo responded to the request for quotations issued by SaskPower by submitting requested information pertaining to Red Lily II.

Successful development of wind projects is subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs and construction risk that the project is built without mechanical defects and is completed on time and within budget estimates.

Windsor Locks

The Windsor Locks facility is a 54 MW natural gas power generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom Windsor Locks, LLC (“Ahlstrom”), a leading paper and non-woven materials manufacturer, pursuant to an energy services agreement (“ESA”) which expires in 2017.

The balance of Windsor Locks’ electrical generating capacity is sold to customers through the ISO-NE electrical market. The facility currently participates in the ISO-NE Forward Capacity Market and the day-ahead energy market. Assuming acceptable auction pricing is available in April 2011, the additional electrical capacity of approximately 26 MW at the Windsor Locks facility will be made available into the summer 2011 Forward Reserve Market. In addition, APCo’s Energy Services Business will use the production from the Windsor Locks facility to support retail industrial electrical sales in the ISO-NE market.

APCo has completed preliminary engineering and environmental permitting work for the installation of a 14.2 MW combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of Ahlstrom. The total expected capital cost for this project is estimated at approximately U.S. $20 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million to offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to Windsor Locks of approximately $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO-NE market. APCo also believes that this project would qualify for a combined heat and power Investment Tax Credit (“ITC”) grant program sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant. APCo’s decision to make any investment in new capital for this site will be based on an assessment of the incremental earnings against such additional investment.

During 2011, it is expected that APCo will continue to earn revenue from steam and electrical sales to Ahlstrom, steam and electrical capacity payments made by Ahlstrom, as well as energy and capacity payments through sales to ISO-NE. Under the expected NE-ISO operating protocol APCo will need to acquire approximately 0.9 million MMBTU of natural gas annually in addition to the amount of natural gas purchased to serve the needs of Ahlstrom (in respect of which APCo receives reimbursement from Ahlstrom under the ESA).

Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the U.S.

In addition to Red Lily II, APCo is currently collecting wind data on three sites in Saskatchewan and responded to Saskatchewan’s Request for Qualifications to procure up to 175 MW of wind power from one or more independent power producers. These sites have met the qualifications and APCo will likely submit project proposals into future RFPs.

Discussions with the OPA indicate that energy procurement initiatives have been positively influenced by the GEA. The GEA is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by APCo as positive for the development of renewable energy in Ontario. The Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the OPA in accordance with the GEA.

APCo had previously submitted applications for approximately 120 MW of on-shore wind energy projects in eastern Ontario under the GEA’s FIT program. The on-shore wind price set by the FIT program is $0.135 per KWh. In February 2011, APCo received notification that a power purchase agreement was awarded for its 75 MW Amherst Island wind project, approximately 25km from Kingston, Ontario. APCo has received confirmation from the OPA that the remaining 45 MW of applications submitted under the FIT program are now being reviewed under the Economic Connection Test.

APCo has applied to become applicant of record for three Crown land sites in Ontario under the Ministry of Natural Resources wind power site release program.

Each project being contemplated is subject to a significant level of due diligence and financial modeling to ensure it satisfies return and diversification objectives established for the Development division. Accordingly, the likelihood of proceeding with some or all of these projects depends on the outcome of due diligence, material contract negotiations, the structure of future calls for tender, and request for proposal programs. To maximize APCo's opportunities for development, new renewable and high efficiency thermal energy generating facilities are being pursued utilizing a variety of technologies and in diverse geographic locations.

Future Development Projects – Existing Facilities

APCo is exploring multiple options related to the St. Leon facility including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 85 MW. In the event these projects are developed, it is currently estimated to require an investment of approximately $250 million.

Future Development Projects – Other

APCo has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. APCo believes this project is an excellent fit for the Minister of Energy and Infrastructure's (the "Ministry") Directive to procure electricity from combined heat and power projects. The Ministry is currently taking registrations from interested parties that wish to participate in such a program.

LIBERTY WATER

	Twelve months ended December 31		Twelve months ended December 31	
	2010	2009	2010	2009
Number of				
Wastewater connections			**35,420**	34,679
Wastewater treated (millions of gallons)			**2,000**	1,925
Water distribution connections			**37,666**	36,919
Water sold (millions of gallons)			**5,500**	5,900
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,258**	147,581		
Revenue				
Wastewater treatment	**$ 19,979**	$ 17,983	**$ 20,704**	$ 20,601
Water distribution	**15,877**	14,996	**16,453**	17,179
Other Revenue	**603**	640	**629**	733
	$ 36,459	$ 33,619	**$ 37,786**	$ 38,513
Expenses				
Operating expenses	**(21,250)**	(20,055)	**(22,074)**	(23,158)
Other income	**82**	1,220	**85**	1,368
Business Unit operating profit (including other income)	**$ 15,291**	$ 14,784	**$ 15,797**	$ 16,723

Liberty Water is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Water has presented the division's results in both the reporting currency and its functional currency. Liberty Water believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Water's functional currency without the impact of foreign exchange.

Liberty Water reports total connections, inclusive of vacant connections rather than customers. Liberty Water had 35,420 wastewater connections as at December 31, 2010, as compared to 34,679 as at December 31, 2009, an increase of 741 in the period or 2.1%. Liberty Water had 37,666 water distribution connections as at December 31, 2010, as compared to 36,919 as at December 31, 2009, representing an increase of 747 in the period or 2.0%. Total connections include approximately 1,900 vacant wastewater connections and 1,400 vacant water distributions connections as at December 31, 2010. Bad debt expense in 2010 decreased by approximately $0.1 million compared to 2009. Liberty Water's change in water distribution and wastewater treatment customer base during the period is primarily due to the acquisition of a small utility in Texas during the first quarter of 2010 and modest growth at Liberty Water's other facilities.

Liberty Water has investments in regulatory assets of U.S. $155.3 million across four states as at December 31, 2010, as compared to U.S. $147.6 million as at December 31, 2009 and has substantially completed proceedings in Texas and Arizona to allow it to earn its full regulatory return on its investment in regulatory assets.

2010 Annual Operating Results

During the year ended December 31, 2010, Liberty Water provided approximately 5.5 billion U.S. gallons of water to its customers, treated approximately 2.0 billion U.S. gallons of wastewater and sold approximately 345 million U.S. gallons of treated effluent.

For the year ended December 31, 2010, Liberty Water's revenue totalled U.S. $36.5 million as compared to U.S. $33.6 million during the same period in 2009, an increase of U.S. $2.8 million or 8.4%.

Revenue from water distribution totalled U.S. $15.9 million as compared to U.S. $15.0 million during the same period in 2009, an increase of U.S. $0.9 million or 5.9%. The annual water distribution revenue was impacted by an increase of U.S. $0.6 million at the four Texas Silverleaf facilities primarily due to the implementation of rate increases, U.S. $0.3 million related to the acquisition of a facility in Galveston, Texas ("Galveston") and U.S. $0.1 million at the Litchfield Park Service Company ("LPSCo") facility due to a net increase in revenues from residential customers offset by decreased revenues from commercial customers in the first quarter of 2010, partially offset by decreased revenue of U.S. $0.1 million at the four facilities as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. $20.0 million, as compared to U.S. $18.0 million during the same period in 2009, an increase of U.S. $2.0 million or 11.1%. The annual wastewater treatment revenue was impacted by increased revenue, primarily due to the implementation of rate increases, of U.S. $1.0 million at the four Texas Silverleaf and Woodmark facilities. The Tall Timbers, LPSCo and Black Mountain facilities saw increased revenue of U.S. $1.0 million primarily due to the combination of the implementation of rate increases and higher residential customer demand. The annual wastewater treatment revenue was also impacted by increased revenue of U.S. $0.3 million related to the acquisition of Galveston as compared to the same period in 2009. These increases were partially offset by decreased wastewater treatment revenue of U.S. $0.1 million due to lower treated effluent revenue at the Gold Canyon facility as compared to the same period in 2009.

For the year ended December 31, 2010, operating expenses totalled U.S. $21.3 million, as compared to U.S. $20.1 million during the same period in 2009. Overall expenses increased U.S. $1.2 million or 6.0% as compared to the same period in 2009. Operating expenses increased U.S. $0.8 million as a result of increased wages, salary and other operating costs, $0.3 million related to rate case costs which, based on the rate case decisions, must be expensed, $0.2 million relating to legal expenses and U.S. $0.2 million as a result of increased equipment rental and transportation costs, partially offset by decreases of U.S. $0.1 million in reduced repair and maintenance expenses and $0.4 million in reduced contracted services expenses as compared to the same period in 2009.

During the year ended December 31, 2009, Liberty Water earned other income of U.S. $1.2 million on the disposition of excess land. During the year ended December 31, 2010, Liberty Water did not dispose of any significant land or other assets.

For the year ended December 31, 2010, Liberty Water's operating profit totalled U.S. $15.3 million as compared to U.S. $14.8 million in the same period in 2009, an increase of U.S. $0.5 million or 3.4%. Excluding other income, which includes a non-recurring gain on disposition of other assets (2009 - U.S. $1.2 million), operating profits increased by $1.6 million or 12.1%. Liberty Water's operating profit did not meet expectations for the year ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Measured in Canadian dollars, for the year ended December 31, 2010, Liberty Water's revenue totalled $37.8 million as compared to $38.5 million during the same period in 2009, a decrease of $0.7 million. Revenue from wastewater treatment totalled $20.7 million, as compared to $20.6 million during the same period in 2009, a decrease of $0.1 million. Revenue from water distribution totalled $16.5 million, as compared to $17.2 million during the same period in 2009, a decrease of $0.7 million. Liberty Water reported decreased revenue from operations of $3.6 million in 2010 as a result of the stronger Canadian dollar as compared to the same period in 2009.

Measured in Canadian dollars, for the year ended December 31, 2010, operating expenses totalled $22.1 million, as compared to $23.2 million during the same period in 2009. Liberty Water reported lower expenses from operations of $2.3 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the year ended December 31, 2010, Liberty Water's operating profit totalled $15.8 million as compared to $16.7 million in the same period in 2009, a decrease of $0.9 million or 5.5%. Excluding other income, which includes a non-recurring gain on disposition of other assets (2009 - $1.4 million), operating profits increased by $0.4 million or 2.3%. Liberty Water's operating profit did not meet expectations for the year ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

	Three months ended December 31		Three months ended December 31	
	2010	**2009**	**2010**	**2009**
Number of				
Wastewater connections			**35,420**	34,679
Wastewater treated (millions of gallons)			**500**	450
Water distribution connections			**37,666**	36,919
Water sold (millions of gallons)			**1,400**	1,400
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,258**	147,581		
Revenue				
Wastewater treatment	**5,334**	4,526	**5,436**	4,815
Water distribution	**4,096**	3,496	**4,174**	3,719
Other Revenue	**189**	142	**174**	153
	$ 9,619	$ 8,164	**$ 9,784**	$ 8,687
Expenses				
Operating expenses	**(5,143)**	(4,660)	**(5,245)**	(4,976)
Other income	**17**	(40)	**17**	(43)
Business Unit operating profit (including other income)	**$ 4,493**	$ 3,464	**$ 4,556**	$ 3,668

2010 Fourth Quarter Operating Results

During the quarter ended December 31, 2010, Liberty Water provided approximately 1.4 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 90 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2010, Liberty Water's revenue totalled U.S. $9.6 million as compared to U.S. $8.2 million during the same period in 2009, an increase of U.S. $1.4 million or 17.5%.

Revenue from water distribution totalled U.S. $4.1 million, as compared to U.S. $3.5 million during the same period in 2009, an increase of U.S. $0.6 million or 16.5%. The fourth quarter water distribution revenue was impacted by an increase of $0.1 million at the four Texas Silverleaf facilities primarily due to increased customer demand, U.S. $0.4 million at the LPSCo facility primarily due to the implementation of rate increases and U.S. $0.1 million related to the acquisition of Galveston as compared to the same period in 2009. In addition, the division experienced increased customer demand at four water distribution facilities as compared to the same period in 2009.

Revenue from wastewater treatment totalled U.S. $5.3 million, as compared to U.S. $4.5 million during the same period in 2009, an increase of U.S. $0.8 million or 17.9%. The fourth quarter wastewater treatment revenue was impacted by increased revenue of U.S. $0.2 million at the four Texas Silverleaf and Tall Timbers facilities primarily due to increased customer demand, increased revenue of U.S. $0.6 at the Woodmark, Black Mountain and the LPSCo facilities, primarily due to the implementation of rate increases and U.S. $0.1 million related to the acquisition of Galveston as compared to the same period in 2009.

For the quarter ended December 31, 2010, operating expenses totalled U.S. $5.1 million, as compared to U.S. $4.7 million during the same period in 2009. Overall expenses increased U.S. $0.5 million or 10.4% as compared to the same period in 2009. Operating expenses increased due to increased legal, insurance and property taxes of U.S. $0.4 million, $0.3 million related to rate case costs which, based on the rate case decisions, must be expensed, partially offset by decreases of U.S. $0.1 million related to wages, salary and other operating costs and U.S. $0.1 million related to bad debt expense as compared to the same period in 2009. In the comparable period, the division capitalized U.S. $0.6 million related to rate case costs which were previously expensed due to the adoption of rate regulated accounting during the fourth quarter of 2009.

For the quarter ended December 31, 2010, Liberty Water's operating profit totalled U.S. $4.5 million as compared to U.S. $3.5 million in the same period in 2009, an increase of U.S. $1.0 million or 29.7%. Liberty Water's operating profit did not meet expectations for the three months ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Measured in Canadian dollars, for the quarter ended December 31, 2010, Liberty Water's revenue totalled $9.8 million, as compared to $8.7 million during the same period in 2009. Revenue from wastewater treatment totalled $5.4 million, as compared to $4.8 million during the same period in 2009, an increase of $0.6 million. Revenue from water distribution totalled $4.2 million, as compared to $3.7 million in the same period in 2009, an increase of $0.4 million. Liberty Water reported decreased revenue from operations of $0.3 million in the fourth quarter of 2010 as a result of the stronger Canadian dollar as compared to the same period in 2009.

Measured in Canadian dollars, for the quarter ended December 31, 2010, operating expenses totalled $5.2 million, as compared to $5.0 million during the same period in 2009. Liberty Water reported lower expenses from operations of $0.2 million as a result of the stronger Canadian dollar, as compared to the same period in 2009.

For the quarter ended December 31, 2010, Liberty Water's operating profit totalled $4.6 million as compared to $3.7 million in the same period in 2009, an increase of $0.9 million or 24.2%. Liberty Water's operating profit did not meet expectations for the three months ended December 31, 2010 primarily due to delays in receiving final decisions in respect of its current rate cases.

Outlook – Liberty Water

Liberty Water expects continuing modest customer growth in 2011. Liberty Water provides water distribution and wastewater collection and treatment services, primarily in the southern and southwestern U.S. where communities have traditionally experienced long-term growth and that provide continuing future opportunities for organic growth.

Revenue increases from rate cases completed in Arizona and Texas on an annualized basis will contribute an additional U.S. $10.2 million in revenue in Liberty Water. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. $1.1 million in annual revenue requirement is expected to be concluded by the first quarter of 2011.

Liberty Water continues to work with key stakeholders, including regulators, to help manage issues related to the issuance of decisions in its rate cases in a timely manner.

Completed Rate Cases	Date of Rate Increases	Annual U.S. $ Revenue Increase Requested	Annual U.S. $ Revenue Increase Granted
Facility			
Arizona			
Black Mountain	October 2010	$ 1.0 million	$ 0.7 million
Litchfield Park Service Company	December 2010	$ 11.6 million	$ 7.1 million
Rio Rico	February 2011	$ 1.6 million	$ 0.9 million
Texas			
Texas Utilities (Silverleaf – 4 utilities)	October 2009	$ 1.2 million	$ 1.2 million
Tall Timbers	July 2009	$ 0.2 million	$ 0.2 million
Woodmark	January 2010	$ 0.1 million	$ 0.1 million

Rate Cases Awaiting Recommended Order & Opinion		Estimated Annual U.S. $ Revenue Increase Requested
Facility		
Arizona		
Bella Vista, Northern and Southern Sunrise	$	1.1 million

Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Water monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

In Arizona, the ACC requires a full regulatory process for all rate cases using a historic test year. On August 5, 2010, Liberty Water received a recommended order ("ROO") for its Black Mountain Sewer Company recommending an annualized rate increase of approximately $0.7 million. The ROO was approved in entirety at the Commission's open meeting held in August.

On October 5, 2010, Liberty Water received a ROO for the LPSCo facility proposing an annualized revenue increase of $8.1 million. At the ACC open meeting held on December 10, 2010 to consider the ROO, the approved revenue increase was reduced to $7.1 million. As part of the LPSCo ROO, the rate increase will be phased in with 50% of the increase being applied in the first 6 months, increasing to 75% for 6 months thereafter, and 100% of the rate increase being realized from month 12 forward. LPSCo is entitled to recover the foregone revenue from the phase in of rates including carrying charges under terms to be determined during the second phase of the LPSCo rate case which focuses on amounts charged for hookup fees. This phase is expected to occur later in 2011.

On December 11, 2011, the ACC approved an order authorizing an annualized rate increase of $0.9 million for Rio Rico Utilities Inc., effective February 1, 2011. It is anticipated that the regulatory review of the proposed rates and tariffs for Bella Vista, Northern Sunrise, and Southern Sunrise will be completed in Q1 2011.

In Texas, the Texas Commission on Environmental Quality ("TCEQ") allows the utility's customers a period of 90 days from the effective date of the proposed rates to object to the imposition of interim rates pending final rates determination. If greater than 10% of a specific Texas utility's customers object to the new proposed rates, the proposed rates would be subjected to a full regulatory hearing process administered by the TCEQ in order to finalize the rates. If fewer than 10% of the customers record an objection to the proposed rates, those proposed rates are likely to be adopted and declared final as proposed. Any difference between the interim rates charged and collected and the final rates as approved by TCEQ will be subject to a retroactive adjustment and refund on the customers' subsequent monthly bill.

Liberty Water entered into negotiated settlements with the customers of the Texas Silverleaf and Tall Timbers facilities, resulting in the achievement of the full estimated annualized revenue increase of $1.2 million and $0.2 million, respectively. The Woodmark facility did not receive objections from 10% of the customer base and also achieved the full estimated annualized revenue increase of $0.1 million.

Liberty Energy

LIBERTY ENERGY

Liberty Energy's business strategy is to build its portfolio of electric and natural gas distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best-in-class customer care for its utility ratepayers.

In 2009, Liberty Energy announced plans to acquire the California Utility, in partnership with Emera. The acquisition was approved by both the CPUC and the Public Utilities Commission of Nevada in the fourth quarter of 2010. The transaction was completed on January 1, 2011 for a purchase price of approximately U.S. $131.8 million, subject to certain working capital and other closing adjustments. The acquisition was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility, entered into on December 29, 2010. Liberty Energy's ownership share of the cost of acquisition of the California Utility was primarily funded through the proceeds of subscription receipts held by Emera for 8.532 million APUC common shares at a price of $3.25 per share.

On December 9, 2010, Liberty Energy entered into agreements to acquire all issued and outstanding shares of Granite State, a regulated New Hampshire electric utility, and EnergyNorth, a regulated New Hampshire natural gas utility from National Grid for total consideration of U.S. $285.0 million which represents a multiple of 1.136 times the aggregate expected regulatory assets. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. Granite State's load and customer counts have shown a consistent 1.6% compounded annual growth over the past 10 years. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. EnergyNorth has a well diversified customer base with no individual customer accounting for more than 3% of gas volumes delivered. Both Granite State and EnergyNorth have capable and experienced work forces which will continue with the businesses following closing.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the fall of 2011. Financing of the acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Energy is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate premium of 5% to the closing price on December 8, 2010. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost of acquisition of Granite State and EnergyNorth. The issuance of these subscription receipts is subject to regulatory approval.

APUC: Corporate

	Three months ended December 31		Twelve months ended December 31	
	2010	**2009**	**2010**	**2009**
Corporate and other expenses:				
Administrative expenses and management costs	**5,126**	2,742	**14,886**	11,562
Write down of property and notes	**2,492**	6,457	**2,492**	6,457
Management internalization expense	**—**	4,693	**—**	4,693
Other corporatization expenses	**—**	3,460	**—**	3,460
Loss / (Gain) on foreign exchange	**(54)**	(258)	**(528)**	(1,261)
Interest expense	**6,719**	5,645	**25,612**	21,387
Interest, dividend and other Income	**(985)**	(738)	**(3,599)**	(2,986)
Loss (gain) on derivative financial instruments	**(1,842)**	(1,515)	**1,103**	(17,318)
Income tax recovery	**(15,539)**	(10,662)	**(20,228)**	(17,927)

2010 Annual Corporate and Other Expenses

During the year ended December 31, 2010, management and administrative expenses totalled $14.9 million, as compared to $11.6 million in the same period in 2009. The expense increase in the twelve months ended December 31, 2010 results from increased capital taxes resulting from APUC's effective conversion to a corporation in 2009, increased legal, audit, tax and other professional fees associated with APUC being registered with the SEC as a foreign private issuer, Algonquin continuing to be registered as reporting issuer in 2010, the corporate reorganization of the Liberty Water division and additional salaries related to the internalization of management and administering APUC's operations as compared to the same period in 2009. In the comparable period, administrative expenses of $2.2 million were considered costs related to APUC's conversion to a corporation and classified as other corporatization expenses.

In December 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1.8 million representing the difference between the carrying value of the assets and their fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities. In December 2010, the equipment at the Crossroads thermal facility in New Jersey met the conditions for *"asset held for sale"*. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

In the comparable period in 2009, APCo decided to dispose of its investments in its remaining LFG facilities and its 50% ownership in the Drayton Valley facility. As a result of testing its investments for recoverability using a net realizable value valuation technique, APCo determined that these assets were impaired as at December 31, 2009. Accordingly, for the year ended December 31, 2009, APCo recognized an impairment charge of $1.1 million against the outstanding principal balance of a note receivable related to its LFG operations. APCo also wrote down the carrying value of its remaining LFG facilities and its 50% investment in the Valley Power facility to their estimated current fair value. This resulted in a write-down of property and equipment of $4,854 in the period representing the difference between the carrying value of the assets and their net realizable values.

During the year ended December 31, 2010, there were no costs recorded in association with management internalization. During the comparable period in 2009, APUC recorded an expense of $4.7 million with regards to an agreement to acquire the Manager's interest in the management services agreement and internalize management in exchange for shares of APUC. On December 21, 2009, the Board ratified an agreement in principal with the shareholders of APMI to acquire the management contract and internalize management. Senior management expenses have been recorded within the Administrative Expense category on a go forward basis.

During the year ended December 31, 2010, there were no costs recorded associated with converting Algonquin to a corporation. During the comparable period, APUC recorded an expense of $3.5 million associated with costs of converting the Fund to a corporation.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and working capital balances held by Canadian operating entities and do not impact current cash position. During the twelve months ended December 31, 2010, APUC classified all of its power generation operating facilities based in the U.S. as self-sustaining. As a result, foreign exchange translation gains and losses of U.S. denominated debt and working capital balances in these U.S. operating entities after January 1, 2010 no longer flow though the consolidated statement of operations. For the twelve months ended December 31, 2010, APUC reported a foreign exchange gain in relation to U.S. assets held by Canadian entities of $0.5 million as compared to a gain of $1.3 million during the same period in 2009. The twelve months ended December 31, 2010 experienced a decrease in value of the U.S. dollar of 5.4% which resulted in unrealized gains on APUC's U.S. dollar denominated debt and working capital balances held by Canadian entities. In the comparable period in 2009, APUC's power generation operating facilities based in the U.S. were classified as integrated and the decrease in the value of the U.S. dollar of 14.2% experienced in the period resulted in unrealized translation gains on APUC's U.S. dollar denominated debt and working capital balances held by its integrated U.S. operating facilities.

For the twelve months ended December 31, 2010, interest expense totalled $25.6 million as compared to $21.4 million in the same period in 2009. Interest expense increased as a result of higher levels of convertible debentures and increased interest rates charged on variable rate debt, partially offset by decreased interest expense resulting from lower average borrowings on APUC's variable interest rate credit facilities, as compared to the prior year.

For the twelve months ended December 31, 2010, interest, dividend and other income totalled $3.6 million as compared to $3.0 million in the same period in 2009. Interest, dividend and other income primarily consists of dividends from APUC's share investments in the Kirkland and Cochrane facilities and interest related to APUC's subordinated debt interest in the Red Lily I project. The income earned on the investments in the Kirkland and Cochrane facilities was previously allocated to interest and other income in the Thermal Energy division.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on foreign exchange forward contracts, interest rate swaps and forward energy contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $20.2 million was recorded in the twelve months ended December 31, 2010, as compared to a recovery of $17.9 million during the same period in 2009. There are two primary reasons for the income tax recovery for the year. First, in the fourth quarter of 2010, APUC completed the Liberty Water portion of its overall capital structure project. The objective of the capital structure project was to ensure that APUC's operating subsidiaries each have a capital structure that is appropriate for the business sector and functional currency in which it operates. Therefore as part of this process, APUC converted certain Canadian dollar denominated intercompany notes with Liberty Water into US dollar denominated notes resulting in a realized foreign exchange loss for tax purposes, thereby creating a future tax asset of approximately $12 million that is now available as additional tax shelter in future years. Secondly, on October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. Included in future income tax recoveries for the year ended December 31, 2010 is $6.6 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2010 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2010, management and administrative expenses totalled $5.1 million, as compared to $2.7 million in the same period in 2009. The expense increase in the three months ended December 31, 2010 results from those factors identified in the discussion of the annual expense noted above as compared to the same period in 2009.

In December 2010, APCo wrote down its investment in three small hydro facilities and determined that the equipment at the Crossroads thermal facility in New Jersey met the conditions for *"asset held for sale"*. See the discussion in the annual corporate and other expenses section above for details related to this expense.

In the comparable period in 2009, APCo decided to dispose of its investments in its remaining LFG facilities and its 50% ownership in the Drayton Valley facility. See the discussion in the annual corporate and other expenses section above for details related to this expense.

During the year ended December 31, 2010, there were no costs recorded in association with management internalization. During the comparable period in 2009, APUC recorded an expense of $4.7 million with regards to an agreement to acquire the Manager's interest in the management services agreement and internalize management. See the discussion in the annual corporate and other expenses section above for details related to this expense.

During the year ended December 31, 2010, there were no costs recorded associated with converting the Fund to a corporation. During the comparable period, APUC recorded an expense of $3.5 million associated with costs of converting the Fund to a corporation.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and working capital balances held by Canadian operating entities and do not impact current cash position. For the three months ended December 31, 2010, APUC reported a foreign exchange gain of $0.1 million as compared to a gain of $0.3 million during the same period in 2009. The three months ended December 31, 2010 experienced a decrease in value of the U.S. dollar of 3.3% which resulted in unrealized gains on APUC's U.S. dollar denominated debt and working capital balances held by Canadian entities. In the comparable period in 2009, APUC's power generation operating facilities based in the U.S. were classified as integrated and the decrease in the value of the U.S. dollar of 2.8% experienced in the quarter resulted in unrealized translation gains on APUC's U.S. dollar denominated debt and working capital balances held by its integrated U.S. operating facilities.

For the quarter ended December 31, 2010, interest expense totalled $6.7 million as compared to $5.6 million in the same period in 2009. Interest expense increased as a result of higher levels of convertible debentures, and increased average interest rates charged on APUC's variable interest rate credit facilities, partially offset by lower average borrowings on APUC's variable interest rate credit facilities, as compared to the prior year.

For the quarter ended December 31, 2010, interest, dividend and other income totalled $1.0 million as compared to $0.7 million in the same period in 2009. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities and interest related to APUC's subordinated debt interest in the Red Lily I project. The income earned on the investments in the Kirkland and Cochrane facilities was previously allocated to interest and other income in the Thermal Energy division.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on foreign exchange forward contracts, interest rate swaps and forward energy contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $15.5 million was recorded in the three months ended December 31, 2010, as compared to a recovery of $10.7 million during the same period in 2009. The income tax recovery for the three months ended December 31, 2010 results from those factors identified in the discussion of the annual income tax expense noted above. Included in future income tax recoveries for the three months ended December 31, 2010 is $2.4 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense which are non-cash and derived from a number of non-operating factors, accounting methods and assumptions. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended December 31		Twelve months ended December 31	
	2010	**2009**	**2010**	**2009**
Net earnings (loss)	**$ 16,888**	$ (1,366)	**$ 19,639**	$ 31,257
Add:				
Income tax recovery	**(15,539)**	(10,662)	**(20,228)**	(17,927)
Interest expense	**6,719**	5,645	**25,612**	21,387
Write down of property, plant and equipment	**2,492**	5,354	**2,492**	5,354
Write down of note receivable	—	1,103	—	1,103
Management internalization costs	—	4,693	—	4,693
Other corporatization costs	—	3,460	—	3,460
(Gain) / loss on derivative financial instruments	**(1,842)**	(1,515)	**1,103**	(17,318)
Gain on foreign exchange	**(54)**	(258)	**(528)**	(1,261)
Amortization	**11,900**	11,350	**46,573**	45,883
Other	**129**	223	**444**	2,737
Adjusted EBITDA	**$ 20,693**	$ 18,027	**$ 75,107**	$ 79,368

For the year ended December 31, 2010, Adjusted EBITDA totalled $75.1 million as compared to $79.4 million, a net decrease of $4.3 million or 5.4% as compared to the same period in 2009. For the quarter ended December 31, 2010, Adjusted EBITDA totalled $20.7 million as compared to $18.0 million, an increase of $2.7 million or 14.8% as compared to the same period in 2009. The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

	Three months ended December 31 2010	Twelve months ended December 31 2010
Comparative Prior Period Adjusted EBITDA	$ 18,027	$ 79,368
Significant Changes:		
Administration and management costs	(2,400)	(3,300)
Hydro Renewable – primarily due to lower hydrology	200	(3,400)
Lower results from stronger Canadian dollar	(100)	(3,000)
Windsor Locks – change in operating model	—	(2,300)
St. Leon – primarily due to a lower wind resource	800	(1,900)
EFW – impact of shutdown	700	(1,700)
Liberty Water gain on sale of excess land	—	(1,400)
Acquisition of Tinker Hydro in Q1 2010	2,800	9,900
Red Lily – development fees	600	2,100
Liberty Water revenue increases primarily due to rate case approvals	1,600	2,000
Other	(1,534)	(1,261)
Current Period Adjusted EBITDA	$ 20,693	$ 75,107

Reconciliation of adjusted net earnings to net earnings

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. APUC uses adjusted net earnings to assess the performance of APUC without the effects of gains or losses on foreign exchange, foreign exchange forward contracts and interest rate swaps as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of APUC's businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended December 31		Twelve months ended December 31	
	2010	**2009**	**2010**	**2009**
Net earnings (loss)	**$16,888**	$ (1,366)	**$19,639**	$ 31,257
Add:				
Loss (gain) on derivative financial instruments, net of tax	**(1,292)**	(757)	**(1,688)**	(13,378)
Write down of property and notes, net of tax	**2,492**	6,379	**2,492**	6,379
Management internalization expense, net of tax	**—**	4,693	**—**	4,693
Other corporatization expenses, net of tax	**—**	2,813	**—**	2,813
Gain on foreign exchange, net of tax	**(54)**	(258)	**(528)**	(1,261)
Adjusted net earnings	**$18,034**	$11,504	**$19,915**	$ 30,503
Adjusted net earnings per share unit	**$ 0.19**	$ 0.14	**$ 0.21**	$ 0.38

For the year ended December 31, 2010, adjusted net earnings totalled $19.9 million as compared to $30.5 million, a decrease of $10.6 million as compared to the same period in 2009. The decrease in adjusted net earnings in the twelve months ended December 31, 2010 is primarily due to higher interest expense and management and administrative expenses as compared to the same period in 2009.

For the three months ended December 31, 2010, adjusted net earnings totalled $18.0 million as compared to adjusted net earnings of $11.5 million, an increase of $6.5 million as compared to the same period in 2009. The increase in adjusted net earnings in the three months ended December 31, 2010 is primarily due to increased earnings from operations and increased future income tax recoveries, partially offset by increased interest expense as compared to the same period in 2009.

SUMMARY OF PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

	Three months ended December 31		Twelve months ended December 31	
	2010	**2009**	**2010**	**2009**
APCo				
Renewable Energy Division				
Capital expenditures	**$ 979**	$ 480	**$ 2,331**	$ 1,114
Acquisition of operating entities	**—**	—	**40,281**	—
Total	**$ 979**	$ 480	**$42,612**	$ 1,114
Thermal Energy Division				
Capital expenditures	**$ 434**	$ 664	**$11,596**	$ 3,521
Total	**$ 434**	$ 664	**$11,596**	$ 3,521
LIBERTY WATER				
Capital Investment in regulatory assets	**$4,584**	$ (427)	**$ 6,644**	$ 6,174
Acquisition of operating entities	**—**	—	**2,121**	—
	$4,584	$ (427)	**$ 8,765**	$ 6,174
LIBERTY ENERGY				
Capital Investment in regulatory assets	**$ —**	$ —	**$ —**	$ —
Acquisition of operating entities	**3,123**	317	**3,123**	1,177
	$3,122	**$ 317**	**$ 3,123**	**$ 1,177**
Consolidated (includes Corporate)				
Capital expenditures	**$1,595**	$1,144	**$14,187**	$ 4,742
Capital investment in regulatory assets	**4,584**	(427)	**6,644**	6,174
Acquisition of operating entities	**3,123**	317	**45,524**	1,177
Total	**$9,302**	$1,034	**$66,240**	$12,093

APUC's consolidated capital expenditures in the twelve months ended December 31, 2010 increased as compared to the same period in 2009 primarily due to the major capital upgrades completed at the EFW facility, the acquisition of the Tinker Assets and the Energy Services Business, costs associated with the acquisition by Liberty Energy of the California Utility and the acquisition by Liberty Water of a water distribution and wastewater treatment facility in Texas.

Property, plant and equipment expenditures for 2011 fiscal year are anticipated to be between $27 million and $34 million, including approximately $8.0 million related to ongoing requirements by Liberty Water, $3.0 million related to Liberty Energy's share of ongoing requirements at the California Utility, $6.5 million related to the APCo Thermal division, and $8.0 million related to the APCo Renewable Energy division.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2010 Annual Property Plant and Equipment Expenditures

During the year ended December 31, 2010, APCo incurred capital expenditures of $14.2 million, as compared to $4.7 million during the comparable period in 2009. APCo also invested $40.2 million to acquire operating assets/entities during the twelve months ended December 31, 2010, as compared to nil million during the comparable period in 2009.

During the twelve months ended December 31, 2010, APCo Renewable Energy division's capital expenditures were $2.3 million, as compared to $1.1 million in the comparable period in 2009. There were no individual projects in excess of $0.5 million initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets relate to the Tinker Assets located in New Brunswick and Maine.

During the twelve months ended December 31, 2010, APCo Thermal Energy division's capital primarily relate to the EFW facility where major maintenance was completed subsequent to the end of the quarter. In the comparable period, the expenditures primarily related to minor capital projects at the hydro-mulch facility and the EFW facility.

During the twelve months ended December 31, 2010, Liberty Water invested maintenance capital of $6.6 million into regulatory assets, as compared to an investment of $6.2 million in the comparable period. During the twelve months ended December 31, 2010, Liberty Water acquired a water and wastewater utility near Galveston

Texas for approximately $2.0 million. In the comparable period in 2009, Liberty Water's expenditures primarily related to the completion and commissioning of projects initiated in 2008.

During the twelve months ended December 31, 2010, Liberty Energy incurred costs associated with the acquisition by Liberty Energy of the California Utility of $3.0 million, as compared to $1.2 million in the comparable period.

As previously noted, these investments have been included in the rate case applications completed as well as those currently underway. In the comparable period, the expenditures primarily related to investment in additional wells, engineering work regarding wastewater treatment operations and arsenic treatment at the LPSCo facility. The expenditures in the comparable period are included in the rate case applications which are currently in process.

2010 Four Quarter Property Plant and Equipment Expenditures

During the three months ended December 31, 2010, APCo incurred capital expenditures of $1.6 million, as compared to $1.1 million during the comparable period in 2009.

During the three months ended December 31, 2010, APCo Renewable Energy division's capital expenditures were not significant, consistent with the comparable period in 2009.

During the three months ended December 31, 2010, APCo Thermal Energy division's capital expenditures were not significant, consistent with the comparable period in 2009.

During the three months ended December 31, 2010, Liberty Water invested maintenance capital of $4.6 million into regulatory assets, as compared to $0.4 million in the comparable period.

During the three months ended December 31, 2010, Liberty Energy incurred costs associated with the acquisition by Liberty Energy of the Calpeco facility of $3.0 million, as compared to $0.3 million in the comparable period.

LIQUIDITY AND CAPITAL RESERVES

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2010 under the senior banking Facility:

	2010 Q4	2010 Q3	2010 Q2	2010 Q1	2009 Q4
Committed and available Facility	$ 142,000*	$ 163,400	$ 162,800	$ 177,950	$ 179,500
Funds Drawn on Facility	(64,500)	(108,900)	(102,800)	(91,650)	(94,000)
Letters of Credit issued	(33,100)	(33,800)	(34,600)	(32,400)	(33,100)
Remaining available Facility	**$ 44,400***	**$ 20,700**	**$ 25,400**	**$ 53,900**	**$ 52,400**
Cash on Hand	5,100	3,100	2,400	750	2,800
Total liquidity and capital reserves	**$ 49,500**	**$ 23,800**	**$ 27,800**	**$ 54,650**	**$ 55,200**

* Reflects availability under a new three year Facility announced on January 14, 2011.

As at and for the period ended December 31, 2010, APUC and Algonquin are in compliance with the covenants under the Facility.

As at December 31, 2010, CAD $64.5 million had been drawn on the Facilities as compared to CAD $94.0 million as at December 31, 2009. On December 22, 2010, Liberty Water obtained a U.S. $50 million long-term private placement financing. The notes are senior unsecured with a 10 year term bearing interest at 5.6%. The notes are interest only until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. Proceeds were used to reduce amounts outstanding under the Facility. In addition to amounts actually drawn, there was $33.1 million in letters of credit outstanding as at December 31, 2010.

Subsequent to the year end, Algonquin concluded negotiations with its bank syndicate on the renewal of the Facility for a three year term with a maturity date of February 14, 2014. Algonquin reduced the total of the Facility as part of its capital structure initiatives to term out some of the short-term borrowings under the Facility.

Under the terms of the new banking agreement, as at December 31, 2010, Algonquin had $44.4 million of committed and available bank facilities remaining and $5.1 million of cash resulting in $49.5 million of total liquidity and capital reserves.

APUC expects to continue to reduce its level of short term borrowings under the Facility through obtaining appropriate long term debt through refinancing certain project specific financings or additional medium to long-term notes. APUC has received and is currently assessing several financing offers to term out the remainder of its short term bank credit facility and project debt coming due in the next three quarters. APUC anticipates concluding its assessments on these offers by the second quarter of 2011.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of December 31, 2010 is shown below:

	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Long-term debt obligations[1]	$259,131	$ 70,490	$ 3,238	$ 68,395	$ 117,008
Convertible Debentures	$185,342	—	—	62,469	122,873
Interest on long-term debt obligations	$164,830	25,670	48,198	35,889	55,073
Purchase obligations	$ 33,506	33,506	—	—	—
Derivative financial instruments:					
Currency forward	$ 45	45	—	—	—
Interest rate swap	$ 5,439	1,959	2,504	976	—
Energy forward contracts	$ 378	378	—	—	—
Capital lease obligations	$ 523	212	243	68	—
Other obligations	$ 9,255	466	931	931	6,927
Total obligations	$658,449	$ 132,726	$ 55,114	$ 168,728	$ 301,881

Long term obligations include regular payments related to long term debt and other obligations.

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

On October 27, 2009, all of Algonquin's trust units were exchanged for shares of APUC that began to be publicly traded on the Toronto Stock Exchange ("TSX") while Algonquin's trust units concurrently ceased trading on the TSX.

As at December 31, 2010, APUC had 95,422,778 issued and outstanding shares on a fully diluted basis. On January 1, 2011, following Emera's exercise of its subscription receipts, APUC had 103,945,778 issued and outstanding shares on a fully diluted basis. The shares issued to Emera were in connection with APUC's partnership with Emera entered into on April 23, 2009 wherein APUC agreed to issue approximately 8.5 million shares of APUC at a price of $3.25 per share to finance a portion of the acquisition of the California Utility.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled: to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC, to receive a pro rata share of any remaining property and assets of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

In 2008, Algonquin entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG"), which was the manager of Highground and a related party of Algonquin controlled by the shareholders of Algonquin Power Management Inc., the former manager of Algonquin ("APMI" or the "Manager"). Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and Algonquin issued equity in the form of trust units to the Highground shareholders and CJIG.

In 2009, APUC's consideration received from the acquisition exceeded $26,970, the minimum contemplated under the agreements, and, as a result APUC is entitled to 50% of any additional proceeds from the assets formerly owned by Highground. CJIG is entitled to the remaining 50% of any proceeds in excess of the minimum amount. During the twelve months ended December 31, 2010, APUC received $0.2 million (2009 - $1.0 million) from CJIG as APUC's share of the 50% of additional proceeds from the further liquidation of the assets held by Highground. This has been recorded as an increased amount assigned to the equity originally issued.

The remaining investments, formerly held by Highground, currently consist of two non-liquid debt assets having an approximate principal amount of $2.2 million. Debt representing $1,000 matured in December 2010 and the balance of the debt matures in the fourth quarter of 2012. Negotiations with the borrower of the $1,000 are currently underway to secure repayment. APUC's 50% share of any additional proceeds from liquidation of the remaining Highground assets will be recorded when received as additional proceeds from the issuance of equity.

On December 21, 2009, the Board reached an agreement with the shareholders of APMI to internalize all management functions of APCo which were provided by the Manager. At a meeting of the shareholders held in June 2010, shareholders approved the issuance of shares in respect of the internalization of management. As a result, APUC acquired the interest previously held by APMI in the management services agreement through the issuance of 1,180,180 APUC shares during the quarter ended June 30, 2010. The management services agreement has since been terminated.

In July 2004, the Fund issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on July 31, 2011 ("Series 1 Debentures"). The Series 1 Debentures bore interest at 6.65% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $10.65 per trust unit, being a ratio of approximately 93.9 trust units for each $1,000 principal. On October 27, 2009, there were 84,964 convertible debentures outstanding with a face value of $84,964.

Pursuant to the CD Exchange Offer, on October 27, 2009, $63,755 of the outstanding Series 1 Debentures were exchanged for convertible debentures bearing interest at 7.5%, maturing on November 30, 2014 ("Series 1A Debentures") convertible unsecured subordinated debentures in a principal amount of $66,943. The remaining Series 1 Debentures having a face value of $21,209, not converted to Series 1A Debentures pursuant to the CD Exchange Offer, were exchanged for 6,607,027 shares of APUC.

The Series 1A Debentures pay interest semi-annually in arrears on January 1 and July 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $4.08 per share, being a ratio of approximately 245.1 shares for each $1,000 principal. The Series 1A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.10 (125% of the conversion price of $4.08). During the period of January 2, 2012 until the debenture's maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional shares.

During the three months ended December 31, 2010, a principal amount of $982 of Series 1A Debentures were converted into 240,646 shares of APUC and a principal amount of $4,473 Series 1A Debentures were converted into 1,096,335 shares of APUC during the twelve months ended December 31, 2010. On December 31, 2010, there were 62,470 Series 1A Debentures outstanding with a face value of $62,470. Subsequent to the end of the quarter, $72 Series 1A Debentures were converted to 17,558 shares of APUC.

In November 2006, the Fund issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016 ("Series 2 Debentures"). The Series 2 Debentures bore interest at 6.2% per annum and were convertible into trust units of the Fund at the option of the holder at a conversion price of $11.00 per trust unit, being a ratio of approximately 90.9 trust units for each $1,000 principal. During the three months ended December 31, 2009 and prior to October 27, 2009, Series 2 Debentures valued at $33,000 were exchanged into 3,000 trust units. These trust units were converted to shares of APUC as a result of the Unit Exchange. On October 27, 2009, there were 59,967 Series 2 Debentures outstanding with a face value of $59,967.

Pursuant to the CD Exchange Offer, on October 27, 2009, all of the outstanding Series 2 Debentures were exchanged for convertible unsecured subordinated debentures bearing interest at 6.35%, maturing on November 30, 2016 ("Series 2A Debentures") in a principal amount of $59,967. The Series 2A Debentures pay interest semi-annually in arrears on April 1 and October 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $6.00 per share, being a ratio of approximately 166.7 shares for each $1,000 principal. The Series 2A Debentures may not be redeemed by APUC prior to January 1, 2011. During the period of January 2, 2011 until January 1, 2012, the debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $7.50 (125% of the conversion price of $6.00). During the period of January 2, 2012 until the debenture's maturity, APUC can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional shares. On December 31, 2010, there were 59,967 Series 2A Debentures outstanding with a face value of $59,967.

On December 2, 2009, APUC issued 63,250 convertible unsecured debentures at a price of $1,000 for each debenture maturing on June 30, 2017 ("Series 3 Debentures"). APUC received net proceeds of $60.7 million after underwriting expenses and before additional issuance costs (gross proceeds of $63.3 million). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures' maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional shares.

On December 31, 2009, there were 63,250 Series 3 Debentures outstanding with a face value of $63,250.

During the three months and year ended December 31, 2010, a principal amount of $345 of Series 3 Debentures was converted into 82,142 shares APUC. On December 31, 2010, there were 62,905 Series 3 Debentures outstanding with a face value of $62,905. Subsequent to the end of the quarter, $105 Series 3 Debentures were converted to 24,999 shares.

SHAREHOLDERS' RIGHTS PLAN

APUC has adopted a Shareholders' Rights Plan (the "Rights Plan"). The Rights Plan is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The TSX has accepted notice for filing of the Rights Plan and the Rights Plan was approved by shareholders at the Meeting until the termination of the annual general meeting of the Shareholders of APUC in 2013 or its termination under the terms of the of Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. Until the occurrence of certain specific events, the rights will trade with the shares of APUC and be represented by certificates representing the shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent or more of the outstanding shares of APUC without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional shares of APUC at a fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Rights Plan, a Permitted Bid is a bid made to all shareholders for all of their shares on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent of the outstanding shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the shares but must extend the bid for a further ten days to allow all other shareholders to tender.

STOCK OPTION PLAN

On June 23, 2010, APUC's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. An option holder may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the "In-The-Money

Amount" represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by APUC in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

On August 12, 2010, the Board approved the grant of 1,102,041 options to select senior executives of APUC. The options allow for the purchase of common shares at a price of $4.05, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2011, 2012 and 2013. Options may be exercised up to eight years following the date of grant.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. At December 31, 2010, APUC recorded $108 (2009 - $nil) in compensation expense. As at December 31, 2010, there was $562 (2009 - $nil) of total unrecognized compensation costs related to non-vested options granted under the Plan. The cost is expected to be recognized over a period of 1.9 years.

No share options were exercised in 2010 or exercisable at December 31, 2010. The intrinsic value of the 1,102,041 non-vested shares as at December 31, 2010 was $1,069 (2009 – nil).

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

- Up to December 21, 2009, APMI provided management services to the Fund including advice and consultation concerning business planning, support, guidance and policy making and general management services. On December 21, 2009, the Board reached an agreement ("Management Internalization Agreement") with APMI to internalize all management functions of Algonquin which were provided by APMI. APUC acquired APMI's interest in the management services agreement, with consideration paid in the form of issuance of 1,158,748 APUC shares (the "Shares"). For accounting purposes, the expense has been measured at $4,693 using a price for each Share of $4.03, the adjusted closing market price on December 21 2009, the date the agreement was ratified. Therefore, for the three and twelve months ended December 31, 2010, APMI was not paid a management fee. For the three and twelve months ended December 31, 2009, APMI was paid on a cost recovery basis for costs incurred and charged $211 and $850 respectively.

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and twelve months ended December 31, 2010 were $82 (2009 - $82) and $327 (2009 - $331) respectively. Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. In 2004, APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the three and twelve months ended December 31, 2010, APUC incurred costs in connection with the use of the aircraft of $60 (2009 - $60) and $430 (2009 - $367), respectively, and amortization expense related to the advance against expense reimbursements of $13 (2009 - $35) and $112 (2009 - $153), respectively. At December 31, 2010, the remaining amount of the advance was $554 (2009 - $666) and is recorded in other assets.
- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a five year period commencing June 17, 2008 growing to a maximum of 10% by year fifteen. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount equal to the debt service on the outstanding debt in respect of such period. The related party holders of the Class B units are entitled to cash distributions of $77 (2009 - $71) and $266 (2009 - $292) for the three and twelve months ended December 31, 2010, respectively.
- During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1.8 million of which APUC agreed to pay APMI $0.1 million. This amount has been accrued and included in accounts payable on the consolidated balance sheet.
- Pursuant to the agreement entered into on June 27, 2008 between Algonquin, Highground and CJIG, APMI was entitled to a fee of approximately $240 from Algonquin. This fee was paid in 2009.
- APUC has operation and maintenance service agreements with three hydroelectric generating facilities owned by affiliates of APMI. As a result of these agreements, APUC employees operate these hydroelectric generating facilities owned by affiliates of APMI. These facilities are charged on a cost recovery basis for time and material incurred at these sites.
- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years to a maximum of 2% after twenty-five years. APUC has agreed to acquire APMI's interest in this royalty for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine the portion of such fee which will be paid following commercial operation of the facility. APUC received and recognized $0.2 million in other revenue related to this fee in the twelve months ended December 31, 2010.
- The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.
- Under these arrangements, as at December 31, 2010 the amount due from the above related party transactions was $718 (2009 - $1,028) and amounts due to related parties was $901 (2009 - $827).
- A member of the Board of Directors of APUC is an executive at Emera. A contract with a subsidiary of Emera to purchase energy on ISO-NE and provide scheduling services on ISO-NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired in the three months ended March 31, 2010 and was not renewed. As a result of this contract, during the three months ended March 31, 2010, a subsidiary of Emera provided services to and

purchased energy on ISO-NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of $1,368 (2009 - $nil) which was included as an operating expense on the consolidated statement of operations.

- On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of MPS. Subsequent to the date of this acquisition, the Energy Services Business sold electricity of U.S. $144 (2009 – nil) to MPS.
- During the period ended June 30, 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO-NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2010 APUC paid U.S. $69 (2009 - $nil) and U.S. $196 (2009 - $nil) in relation to this contract. In the same period, APUC issued a letter of credit to a subsidiary of Emera in an amount of U.S. $500 in conjunction with this contract. Subsequent to December 31, 2010, this letter of credit was replaced with a corporate guarantee.
- APUC believes that the transactions with Emera noted above were in accordance with normal commercial terms.

Business associations with APMI and Senior Executives.

There are a number of continuing business relationships between APUC and one of Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. The Board has initiated a process to review all of the remaining business associations with Senior Executives, APMI and related affiliates in order to reduce, streamline and simplify these relationships. Any acquisitions associated with this process will only proceed if they are expected to be accretive to APUC.

The Board has formed a special committee and intends to engage independent consultants to assist with this process and expects to conclude this process over the next three months.

The co-owned assets and remaining business associations consist of the following:

i) *Rattlebrook hydroelectric generating facility*

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 27.5% by Senior Executives and the remaining percentage by third parties.

ii) *St. Leon wind power generating facility*

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives.

iii) *Brampton Cogeneration Inc.*

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $100 in relation to the development of this project. As of December 31, 2010, this amount is accrued and included in accounts payable on the consolidated balance sheet.

iv) *Long Sault Rapids hydroelectric generating facility*

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.

v) Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2010, $554 of the advance remained.

vi) Office lease

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The lease expires in December 31, 2012. Based on a review of the real estate leasing market at the time, APUC believes the lease was on terms equivalent to fair market value for prime office space of similar size and quality.

vii) Operations services

Staff managed by APUC operate an additional three hydroelectric generating facilities where Senior Executives hold an interest. Each facility is charged on a full cost recovery basis for these staff. Effective January 1, 2011, management of these facilities is being undertaken by a non-APUC related entity. APUC is providing some transition services to the non-APUC entity.

viii) Sanger construction management

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI.

ix) Clean Power Income Fund

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of December 31, 2010 this amount is accrued and included in accounts payable on the consolidated balance sheet.

x) Red Lily I

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. APUC has agreed to acquire APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility.

xi) Trafalgar

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Algonquin moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar had previously won a $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was then reached between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal costs with the proceeds from the lawsuits being shared after reimbursement of legal costs. The Second Circuit Court of Appeals recently dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Water maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, any credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 45% of EBITDA and 60% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately $15.5 million and increased reported expenses from U.S. operations of approximately $11.5 million or a net impact of $4.0 million ($0.038 per share) on an annual basis.

The change in unrealized mark-to-market losses/(gains) on derivative financial instruments resulting from changes in foreign exchange rates relate to contract periods which extend to fiscal 2013. Unrealized mark-to-market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. The following charts provides a summary of the year to date changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Year ended December 30		
	2010	**2009**	**Change**
Foreign Exchange Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$(1,424)**	$(15,682)	**$14,258**
Realized loss/(gain) on derivative financial instruments	**(620)**	284	**(904)**
	$(2,044)	$(15,398)	**$13,354**
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$(2,787)**	$ (7,424)	**$ 4,637**
Realized loss on derivative financial instruments	**5,929**	5,504	**425**
	$ 3,142	$ (1,920)	**$ 5,062**
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$(2,931)**	$ —	**$ (2,931)**
Realized loss on derivative financial instruments	**2,936**	$ —	**$ 2,936**
	$ 5	$ —	**$ 5**
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$(7,142)**	$(23,106)	**$15,964**
Realized loss on derivative financial instruments	**8,245**	5,788	**$ 2,457**
Total loss/(gain) on derivative financial instruments	**$ 1,103**	$(17,318)	**$18,421**

The following chart provides a summary of the quarter over quarter changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Three months ended December 31 2010	2009	Change
Foreign Exchange Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (697)**	$(1,261)	**$ 564**
Realized gain on derivative financial instruments	**(28)**	(148)	**120**
	$ (725)	$(1,409)	**$ 684**
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market loss/(gain) on derivative financial instruments	**$(2,333)**	$(1,627)	**$(706)**
Realized loss on derivative financial instruments	**1,294**	1,520	**(226)**
	$(1,039)	$ (107)	**$(932)**
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (482)**	$ —	**$(482)**
Realized loss on derivative financial instruments	**404**	$ —	**404**
	$ (78)	$ —	**$ (78)**
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$(3,512)**	$(2,888)	**$(624)**
Realized loss on derivative financial instruments	**1,670**	1,372	**298**
Total loss/(gain) on derivative financial instruments	**$(1,842)**	$(1,516)	**$(326)**

APUC previously managed this risk primarily through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. As a result of the current business strategy and lower payout ratio, APUC has determined that the prior practice of hedging 100% of its U.S. currency exposure is no longer appropriate and is taking steps to eliminate its existing forward currency contract program. During the twelve months ended December 31, 2010, APUC terminated forward contracts of $36.8 million. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. For the twelve months ended December 31, 2010, APUC realized cash gains of $0.5 million on managing its forward contracts.

The following chart sets out as at December 31, 2010 the amounts, hedge proceeds and average hedged rates over the term of the foreign exchange forward contracts outstanding. The remaining contracts were terminated subsequent to the end of the quarter:

	Total	2011	2012
Total U.S. $ Hedged	$3,000	$—	$3,000
Total Can. $ Proceeds	$3,000	—	3,000
Average Hedged Rate	$1.000	n/a	$1.000
Unrealized Gain (loss)	**$ (45)**	n/a	**(45)**
Impact of a $0.10 move in exchange rates	**$ 300**	n/a	**$ 300**

Based on the fair value of the forward contracts using the exchange rates as at December 31, 2010, the exercise of these forward contracts will result in the use of cash of $45 in fiscal 2012. Assuming a decrease in the strength of the U.S. dollar relative to the Canadian dollar of $0.10 at December 31, 2010, with a corresponding increase in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by $0.3 million in fiscal 2012.

Market price risk

The majority of APCo's electricity generating facilities sell their output pursuant to long-term PPAs. However, certain of APCo's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each $10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of $1.0 million on an annualized basis.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables. APUC does not believe this risk to be significant as approximately 72% of APCo Renewable Energy division's revenue, approximately 70% of APCo Thermal Energy division's revenue, and over 56% of total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	20,500	25%
Manitoba Hydro	AA	19,700	24%
Ontario Electricity Financial Corporation	A+	8,400	10%
Maine Public Service		4,600	6%
National Grid	A-	3,100	4%
Public Service Company of New Hampshire	BBB	2,800	3%
Total		**$ 59,100**	**72%**
Thermal Energy Division			
Pacific Gas and Electric Company	BBB+	15,700	25%
Regional Municipality of Peel	AAA	14,500	23%
Ahlstrom	1R3	11,400	18%
Connecticut Light and Power Company	BBB	5,800	9%
Total		**$ 65,700**	**70%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2011

The remaining revenue is primarily earned by Liberty Water. In this regard, the credit risk related to Liberty Water accounts receivable balances of U.S. $5.0 million is spread over approximately 70,000 customers, resulting in an average outstanding balance of approximately $72.00 per customer. Liberty Water has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

Interest rate risk

APCo has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Facility has an outstanding balance drawn of CAD $64.5 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by CAD $0.6 million annually. Algonquin had fixed for floating interest rate swap in an amount of CAD $100.0 million which expired on December 31, 2010. At December 31, 2010, the mark-to-market value of the interest rate swap was nil (2009 – $3.3 million net liability).
- APCo's project debt at the St. Leon facility had a balance of $68.8 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by $0.7 million annually. Although the underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank's prime rate, APCo has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt's interest and principal repayment schedule. This minimizes volatility in the interest expense on this debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. APCo has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2010, the mark-to-market value of the interest rate swap was a net liability of $5.4 million (2009 – net liability of $5.0 million).

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2010. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of $0.24 per share per year. On March 3, 2011, the Board approved an annual dividend increase of $0.02 per common share for a total annual dividend of $0.26, paid quarterly at a rate of $0.065 per common share. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensure APUC's long-term success. Based on the level of dividends paid during the three and twelve months ended December 31, 2010, cash provided by operating activities exceeded dividends declared by 3.2 times and 2.0 times respectively.

As at December 31, 2010, APUC had cash on hand of $5.1 million and $44.4 million available to be drawn on the Facility. The Facility was renewed subsequent to December 31, 2010 and therefore the Facility has been classified on the consolidated balance sheet as a long term liability.

APUC reduced its level of short-term borrowings through the renewal of the Facility on February 14, 2011 for a three year term and through a U.S. $50 million private placement debt financing at Liberty Water on December 22, 2010. In addition, APUC continues to seek to reduce short term borrowings by obtaining appropriate long term debt through refinancing certain project specific financings or additional medium to long term notes. See the Liquidity and Capital Reserves section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facility.

The Facility and project specific debt total approximately $257.4 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $1.0 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $1.2 million or a net increase in operating profits of approximately $0.2 million.

- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk buts has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $1.0 million on an annual basis. However, historically, changes in the price of natural gas are generally matched with changes in market electricity prices which should result in a minimal impact on operating profit.
- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately $0.1 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of $0.2 million or a net increase in operating profits of approximately $0.1 million.
- APCo's Energy Services Business provides the short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 130,000 MW-hrs in fiscal 2011. While the Tinker Assets are expected to provide the majority of the energy required to service these customers, the Energy Services Business anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that the Energy Services Business was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $1.3 million on an annualized basis.

  This risk is mitigated though the use of short-term financial energy hedge contracts. APCo has committed to acquire approximately 12,000 MW-hrs of net energy over the next 2 months at an average rate of approximately $70 per MW-hr. The mark-to-market value of these forward energy hedge contracts at December 31, 2010 was a net liability of U.S. $0.4 million.

  Subsequent to December 31, 2010, APCo entered into a financial energy hedge contract to acquire approximately 215,000 MW-hrs of energy over a three year period starting March 1, 2011 at an average rate of approximately $50 per MW-hr.

OPERATIONAL RISK MANAGEMENT

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter. A more detailed assessment of APUC's business risks is also set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. Accordingly, dividends to shareholders are dependent upon the profitability of each of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. The water distribution networks of the Liberty Water operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Water) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

Regulatory Risk

Profitability of APUC businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Water's facilities are subject to rate setting by State regulatory agencies. Liberty Water has five ongoing rate cases before regulatory bodies in Arizona and Texas in varying stages of completion. More details regarding the status of these proceedings are set out in Outlook – Liberty Water. The time between the incurrence of costs and the granting of the rates to recover those costs by utility commissions is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Water and wastewater utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Water, and while Liberty Water believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Water regularly works with these authorities to manage the affairs of the business.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its financial statements.

Generally, APCo's hydroelectric facilities are subject to some form of a water use agreement. The terms of these agreements vary by facility as they are agreements made with the local government body that regulates electrical energy generators and can extend over many years. Certain of the agreements contain clauses which allow the regulating body the option to require APCo to decommission the facility upon the expiry or termination of the agreements. Other facilities have no specific obligations other than to maintain the facility in good working order. APCo has options in many of its existing water use agreements to renew or extend the agreements and anticipates being in a position to extend the majority of its agreements and continue to operate its facilities. Based on historical general practice within the regions in which APCo has facilities, APCo has assessed the probability of being required to decommission a facility upon the expiry of a water use agreement to be remote. As such, any potential asset retirement obligation expense has been assessed as insignificant as the obligation would be incurred well into the future and there is a remote likelihood of being required to decommission a facility.

The Renewable Energy division's St. Leon facility does not own the property on which its turbines are located. In 2004, St. Leon entered into long-term right-of-way agreements with land owners which allowed it to construct and maintain the wind turbines used by the facility on their property. These agreements are for minimum terms of 40 years and, upon expiry or termination, provide the land owners with title to the equipment if it is not decommissioned by APCo at its option. While APCo anticipates being in a position to renew or extend the existing PPA in 2025, in the event that APCo is unable to renew or extend the agreement, or identify another purchaser of the energy, APCo may choose to decommission the facility. APCo has assessed there to be a remote likelihood of incurring any cost to decommission the wind farm.

The APCo Thermal Energy division's EFW facility owns the property on which its facility operates. EFW's current waste incineration agreement expires in 2012 with two five year options to extend. While APCo anticipates being in a position to renew or extend the existing contract in 2012, in the event that APCo is unable to renew or extend the agreement, APCo may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

Liberty Water's facilities operate under agreements with a state or municipal regulator to provide the sole water distribution and/or wastewater treatment services in its area of operations, as set out in the agreements. In general, these facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Water has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging wastewater treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus Liberty Water is allowed to earn a return on its investment.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies. APCo has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APCo has not recorded any contingent liabilities on its financial statements.

To manage these risks responsibly, APUC has ensured the Environmental and Compliance departments have been established within the different operating subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required. In the aggregate, the departments comprise 7 full time equivalent positions based out of head office and have an annual budget of approximately $1.0 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

APUC and its subsidiaries have procedures to prevent and minimize any impact of possible oil spills and soil contamination that meet generally accepted industry practices. APCo's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

The APCo Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric facility include possible dam failure which results in upstream or downstream flooding and equipment failure which result in oil or other lubricants being spilled into the waterway. In addition, the operation of a hydroelectric facility may cause the water in the associated waterway to flow faster, or slower, which could result in water flow issues which impact fish population, water quality and potential increases in soil erosion around a dam facility. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility. Federal regulators in the U.S. inspect certain hydroelectric facilities on an annual basis and complete an environmental inspection every 3-5 years.

The primary environmental risks associated with the operation of a wind farm include potential harm to the local and migratory bird population, potential harm to the local bat population as well as concerns over noise levels and visual 'harm' to the scenic environment around the wind farm. As part of the federal and provincial approval of the St. Leon wind project, certain pre-construction and post construction monitoring studies were required. No significant issues were identified as a result of these studies. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility.

The APCo Thermal Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a cogeneration facility include potential air quality and emissions issues, soil contamination resulting from oil spills and issues around the storage and handling of chemicals used in normal operations. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs regular stack testing and tests the calibration of monitoring equipment. The primary environmental risks associated with the operation of an incineration facility include potential air quality, odour and emissions issues, soil contamination resulting from oil or other chemical spills and issues around the storage and handling of municipal solid waste. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

Liberty Water faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a wastewater treatment facility include potential air quality and odour management issues, wastewater spills and surface and ground water contamination. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Water maintains ongoing sampling and testing programs as required in its operational jurisdiction, including annual field investigations by management. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the wastewater collection system and at the wastewater treatment plants that it operates.

The primary environmental risks associated with the operation of a water distribution facility include risk of groundwater contamination by contaminants such as bacterial, synthetic, organic and inorganic pollutants, consumption and availability of groundwater and ensuring water quality continues to meet and exceed Environmental Protection Agency ("EPA") and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Water maintains a regular sampling and testing program as required in its operational jurisdiction. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the water distribution systems that it operates.

Federal drinking water legislation in the United States requires all drinking water systems to meet specific standards. The costs of complying with drinking water standards form part of a facility's rate case applications.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Specific Environmental Risks

Greenhouse Gas Initiatives:

Several north-eastern U.S. States have formed a coordination group to develop a multi-state green house gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative ("RGGI"), has received backing from several states where APCo operates facilities including Connecticut and New Jersey. RGGI drafted a model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program will be implemented to regulate CO2 emissions from large electrical generation facilities, including the Windsor Locks facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks facility is the only APCo site that is currently affected by the RGGI regulations. As such APCo will be required to purchase approximately 250,000 tons of CO2 allowances per year, equivalent to the total annual CO2 emissions from the Windsor Locks facility for the 2009 to 2012 fiscal years. APCo is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. APCo submitted an application on October 31, 2008 for allowances under the available programs. For 2010, APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks facility to be between $0.2 and $0.4 million.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called the Western Climate Initiative ("WCI"). This group recently released details of its Regional Cap-and-Trade Program, which is scheduled to start on January 1, 2012. Each member state/province is now responsible for developing the draft design of the Regional Cap-and-Trade Program and taking the necessary steps to implement the Program within its jurisdiction. APCo owns and operates the Sanger facility in California and the EFW facility in Ontario and holds investments in two others in Ontario which could be impacted by this program. As this process has just begun, it is too early to determine the potential financial impact on APCo and means available to mitigate this financial impact, if any.

The Carbon Disclosure Project ("CDP") is an independent non-profit organization that represents institutional investors managing over $57.0 trillion of assets. The CDP is specifically working to encourage companies worldwide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both potential physical impacts and regulatory changes that may result in an effort to address climate change.

APCo submitted a baseline greenhouse gas emissions inventory to the CDP at the end of June 2008. The emissions data includes both direct emissions from our processes as well as indirect emissions from purchased power. The emissions inventory has been developed based on guidance from the Greenhouse Gas Protocol. This submission will allow comparisons with other firms to be made, and will also be useful as a baseline for addressing climate change regulations.

Renewable Energy Division:

As a result of certain legislation passed in Quebec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. This is discussed in greater detail within the analysis of results in the Renewable Energy Division.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates four hydroelectric facilities in Ontario. While it is too early to assess the costs of compliance, it is possible that modifications to certain dam structures may be required in order to be compliant with any new regulations should they come into effect. Any capital costs associated with the anticipated modifications are expected to be significantly lower than the expected capital costs related to the Quebec facilities, as there are fewer facilities in Ontario and they are of newer construction.

Liberty Water:

Liberty Water owns and operates the LPSCo facility, a water distribution and waste-water treatment utility servicing the City of Litchfield Park**,** and parts of the City of Goodyear, the City of Avondale and the County of Maricopa, Arizona, where groundwater pollutants, namely trichloroethylene ("TCE") originally employed by a former aerospace manufacturing plant in the nearby City of Goodyear are progressing toward three of the twelve wells that provide water to the LPSCo service area. The EPA began monitoring TCE in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA regular technical meetings in regards to this monitoring program, LPSCo closely monitors its wells for this groundwater pollutant through the sampling and testing of water from wells that are potentially at risk of contamination. To date there have not been any detectable levels of TCE in the water from wells used by LPSCo. EPA's monitoring and control efforts have not indicated that the concentrations are being reduced or fully captured. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are underway. In the event that any wells exceed EPA permitted TCE level, LPSCo would undertake the appropriate actions which may include installing appropriate treatment facilities or removing the well from the water distribution system of the utility. In the event of removal of a well, there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of

LPCSo's customers. In addition, LPSCo has identified alternate sites where replacement wells can be established to replace this lost capacity. The cost of establishing a new well is estimated to be between $2.0 million and $3.5 million depending on the location, depth and other factors. The cost of commissioning a well forms part of the rate base for the utility. Other factors that can impact the cost of a well include, but are not limited to, any requirement to construct wellhead treatment for pollutants, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Water does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2010.

Seasonal fluctuations and hydrology

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized. For Liberty Water's water utilities, demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Wind resource

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

As reported in previous public filings of Algonquin and as discussed above under *"Related Party Transactions"*, APUC and an affiliate of APMI are involved in civil proceedings and bankruptcy proceedings with Trafalgar, Algonquin acquired notes secured by, among other things, seven hydroelectric facilities owned by Traflagar. In 1997, Algonquin moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar had previously won a $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. Trafalgar commenced an action in 1999 in U.S. District Court against Algonquin, APMI and various other entities related to them in connection with, among other things, the sale of the one of the notes by Aetna Life Insurance Company to the Fund and in connection with the foreclosure on the security for the note. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the note, that Algonquin was therefore the holder and owner of the note, and that all other claims by Trafalgar with respect to the transfer of the note were without merit. In 2008 Algonquin filed for summary judgement seeking dismissal of Trafalgar's remaining claims, and the District Court granted this motion on November 6, 2008. On October 22, 2009 Trafalgar filed an appeal from the November 6, 2008 summary judgement to the United States Court of Appeals for the Second Circuit. The Second Circuit Court of Appeals on November 1, 2010 dismissed all the claims against APCo in the civil proceedings. The bankruptcy proceedings are continuing.

On December 19, 1996, the Attorney General of Québec ("Québec AG") filed suit in Québec Superior Court against Algonquin Développement Côte Ste-Catherine Inc. (Développement Hydromega), a predecessor company to an APUC subsidiary. The Québec AG at trial claimed $5.4 million for amounts that the APUC entities have been paying to the federal authority under its water lease with the authority. The APUC entities brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009 and the appeal was heard by the Court of Appeal January 31, 2011. The Côte Ste-Catherine Facility currently pays water lease dues to the federal government, but if the Québec AG is successful in final appeal, an adjustment and/or increase of such amounts is possible.

Obligations to serve

Liberty Water's utility facilities may be located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Water may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Tax risks associated with the Unit Exchange Offer

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of Hydrogenics or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange Offer for APUC. While APUC is confident in its position, such a challenge or legislation could potentially and materially affect the availability or amount of the tax attributes or other tax accounts of APUC.

Disclosure Controls

At the end of the fiscal year ended December 31, 2010, APUC carried out an evaluation, under the supervision of and with the participation of the APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of the Company's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2010, APUC's disclosure controls and procedures were adequately designed and effective in ensuring that: (i) information required to be disclosed by APUC in reports that it files or submits to the Securities and Exchange Commission under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in applicable rules and forms and (ii) material information required to be disclosed in its reports filed under the Exchange Act is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow for accurate and timely decisions regarding required disclosure.

Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the

risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2010 based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2010.

During the year ended December 31, 2010, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2010.

Millions of dollars (except per share amounts)	1st Quarter 2010	2nd Quarter 2010	3rd Quarter 2010	4th Quarter 2010
Revenue	$ 45.9	$ 42.7	$ 45.4	$ 48.9
Net earnings /(loss)	3.5	(2.2)	1.5	16.9
Net earnings / (loss) per share	0.04	(0.02)	0.02	0.18
Total Assets	966.2	983.2	969.4	980.9
Long term debt*	434.0	446.7	452.8	461.0
Dividend/distribution per share	0.06	0.06	0.06	0.06

	1st Quarter 2009	2nd Quarter 2009	3rd Quarter 2009	4th Quarter 2009
Revenue	$ 52.2	$ 46.5	$ 45.1	$ 43.4
Net earnings / (loss)	4.2	15.3	13.1	(1.4)
Net earnings / (loss) per trust unit	0.05	0.20	0.17	(0.03)
Total Assets	974.2	952.4	925.7	1,013.4
Long term debt*	457.6	456.2	445.4	439.9
Distribution per trust unit	0.06	0.06	0.06	0.06

* Long term debt includes long term liabilities, the Facility, convertible debentures and other long term obligations

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $42.7 million and $52.2 million over the prior two year period. A number of factors impact quarterly results including seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the significant fluctuation in the strength of the Canadian dollar which has resulted in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of $16.9 million and a net loss of $2.2 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax expense due to the enactment of Bill C-52 and mark-to-market gains and losses on financial instruments.

Critical Accounting Estimates

APUC prepared its Consolidated Financial Statements in accordance with Canadian GAAP. An understanding of APUC's accounting policies is necessary for a complete analysis of results, financial position, liquidity and trends. Refer to Note 1 to the Consolidated Financial Statements for additional information on accounting principles. The Consolidated Financial Statements are presented in Canadian dollars rounded to the nearest thousand, except per unit amounts and except where otherwise noted.

Additional disclosure of APUC's critical accounting estimates is also available in APUC's MD&A for the year ended December 31, 2009 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Changes in Accounting Policies

APUC's accounting policies are described in Note 1 to the Consolidated Financial Statements for the period ended December 31, 2010. There have been no changes to the critical accounting policies as disclosed in APUC's audited Consolidated Financial Statements for the year ended December 31, 2009 except as disclosed below.

Change in accounting estimates

As a result of the change in its corporate structure, APUC re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the U.S. divisions operate. APUC concluded that the U.S. operations of the Renewable Energy and Thermal Energy divisions no longer should be classified as integrated foreign operations but rather self-sustaining operations. Consequently, these divisions are prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37.6 million resulting from the current rate translation of non-monetary items principally property, plant and equipment and intangible assets as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

Accounting Framework

In 2011, most publicly accountable enterprises in Canada will be required to change the accounting framework under which financial statements are prepared to International Financial Reporting Standards ("IFRS"). The adoption of IFRS is one of the alternatives available to APUC. As an entity with rate-regulated activities, APUC could also avail itself of the one-year deferral approved by the Accounting Standard Board of the Canadian Institute of Chartered Accountants in September 2010. Alternatively, as an existing SEC registrant, APUC could also choose to report its financial statements under U.S. GAAP.

APUC evaluated the three options and assessed which of the three accounting frameworks would provide its shareholders and other interested readers of its financial statements the most useful basis for financial reporting. Considering the short-term nature of the CICA solution and the uncertainty around the eventual adoption of a rate-regulated accounting standard under IFRS, U.S. GAAP financial statements represent the least disruptive accounting framework for readers of APUC's financial statements. This option would result in minimal changes having to be made to its financial statements as there are fewer differences between U.S. GAAP and current Canadian GAAP. U.S. GAAP also includes accounting standards for rate-regulated activities within the financial statements.

As such, APUC has decided to adopt U.S. GAAP effective January 1, 2011 for purposes of Canadian and U.S. reporting requirements. U.S. GAAP reporting is permitted by Canadian securities laws and the TSX for companies subject to reporting obligations under U.S. securities laws.

Changeover to U.S. Generally Accepted Accounting Standards –January 1, 2011

Reconciliation to U.S. GAAP

Canadian GAAP differs in certain material respects from U.S. GAAP. The reconciliation to U.S. GAAP in note 24 of the consolidated financial statements provides a reconciliation to U.S. GAAP of net earnings, balance sheet and deficit for the years ended December 31, 2010 and 2009.

Significant Changes in Accounting Policies upon Conversion

Commencing in the first quarter of 2011, U.S. GAAP will be applied retrospectively to all prior periods. We expect to make changes in our accounting policies to be compliant with U.S. GAAP. Our U.S. GAAP policies are expected to be consistent with the policies we applied in preparing the reconciliation reflected below. As such, the descriptions contained within the reconciliation are anticipated to be reflective of the changes we plan to make in our adoption of U.S. GAAP.

Impact on the organization

As an SEC registrant, APUC reconciles its financial statements from Canadian GAAP to U.S. GAAP for purpose of annual reporting on Form 40-F with the SEC as a foreign private issuer. As a consequence, no significant impact of the transition to U.S. GAAP is expected on APUC's internal controls, information technology systems and financial reporting expertise requirements. No financial covenants are expected to be impacted by APUC's conversion to U.S. GAAP given the few differences that exist with Canadian GAAP.

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Section 5: EX-99.4 (REPORT OF KPMG LLP)

Exhibit 99.4

KPMG LLP
Chartered Accountants
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, Ontario M5H 2S5
Canada

Telephone (416) 777-8500
Fax (416) 777-8818
Internet www.kpmg.ca

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp.:

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Algonquin Power & Utilities Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission".

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Algonquin Power & Utilities Corp. as of December 31, 2010 and 2009, and the related consolidated statements of operations, deficit, comprehensive income (loss) and accumulated other comprehensive income (loss), and cash flows for each of the years in the two-year period ended December 31, 2010, and our report dated March 31, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 31, 2011
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Section 6: EX-99.5 (CONSENT LETTER FROM KPMG LLP)

Exhibit 99.5

KPMG LLP
Chartered Accountants
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, Ontario M5H 2S5
Canada

Telephone (416) 777-8500
Fax (416) 777-8818
Internet www.kpmg.ca

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp.

We consent to the inclusion in this annual report on Form 40-F of:

- our Report of Independent Registered Public Accounting Firm dated March 31, 2011 on the consolidated balance sheets of Algonquin Power & Utilities Corp. ("the Company") as at December 31, 2010 and 2009, and the related consolidated statements of operations, deficit, comprehensive income (loss) and accumulated other comprehensive income (loss), and cash flows for each of the years in the two-year period ended December 31, 2010
- our Independent Auditors' Report dated March 3, 2011 on the consolidated balance sheets of the Company as at December 31, 2010 and 2009, and the related consolidated statements of operations, deficit, comprehensive income (loss) and accumulated other comprehensive income (loss), and cash flows for each of the years in the two-year period ended December 31, 2010
- our Report of Independent Registered Public Accounting Firm dated March 31, 2011 on the Company's internal control over financial reporting as of December 31, 2010

each of which is contained in this annual report on Form 40-F of the Company for the fiscal year ended December 31, 2010.

/s/ KPMG LLP
Chartered Accountants, Licensed Public Accountants

Toronto, Canada March 31, 2011

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Section 7: EX-99.6 (CERTIFICATIONS OF CEO PURSUANT TO SECTION 302)

Exhibit 99.6

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, Ian E. Robertson, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 31, 2011

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

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Section 8: EX-99.7 (CERTIFICATIONS OF CFO PURSUANT TO SECTION 302)

Exhibit 99.7

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, David Bronicheski, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 31, 2011

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

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Section 9: EX-99.8 (CERTIFICATIONS OF CEO PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002)

Exhibit 99.8

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ian E. Robertson, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 31, 2011

By: /s/ Ian E. Robertson
Name: Ian E. Robertson
Title: Chief Executive Officer

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Section 10: EX-99.9 (CERTIFICATIONS OF CFO PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002)

Exhibit 99.9

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2010 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, David Bronicheski, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 31, 2011

By:	/s/ David Bronicheski
Name:	David Bronicheski
Title:	Chief Financial Officer

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AQN 40-F 12/31/2011

Section 1: 40-F (FORM 40-F)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

[Check one]

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011 Commission File Number 000-53808

ALGONQUIN POWER & UTILITIES CORP.

(Exact name of Registrant as specified in its charter)

N/A
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

4911
(Primary Standard Industrial Classification Code Number (if applicable))

N/A
(I.R.S. Employer Identification Number (if applicable))

2845 Bristol Circle
Oakville, Ontario
L6H 7H7, Canada
(905) 465-4500
(Address and telephone number of Registrant's principal executive offices)

C T Corporation System
111 Eighth Avenue
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Name of each exchange on which registered
N/A	N/A

Securities registered or to be registered pursuant to Section 12(g) of the Act.

Common Shares, no par value
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

N/A
(Title of Class)

For annual reports, indicate by check mark the information filed with this form:

☒ **Annual Information Form** ☒ **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

As of December 31, 2011, there were 136,122,780 Common Shares outstanding.

Indicate by check mark whether the Registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the Registrant was required to file such reports); and (2) has been subject to such filing requirements in the past 90 days.

Yes ☒ **No** ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this Chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files)

Yes ☒ No ☐

ANNUAL INFORMATION FORM

The Annual Information Form of Algonquin Power & Utilities Corp. ("Algonquin") for the fiscal year ended December 31, 2011 is filed as Exhibit 99.1 to this annual report on Form 40-F.

AUDITED ANNUAL FINANCIAL STATEMENTS

The Audited Annual Financial Statements of Algonquin for the fiscal year ended December 31, 2011 are filed as Exhibit 99.2 to this annual report on Form 40-F.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis for the fiscal year ended December 31, 2011 is filed as Exhibit 99.3 to this annual report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

The information provided under the heading "Disclosure Controls" (page 48) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2011, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

INTERNAL CONTROL OVER FINANCIAL REPORTING

a. Management's report on internal control over financial reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Algonquin's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control– Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that Algonquin maintained effective internal control over financial reporting as of December 31, 2011.

KPMG LLP, the independent registered public accounting firm of Algonquin, which audited the consolidated financial statements of Algonquin for the year ended December 31, 2011, has also issued an attestation report on the effectiveness of Algonquin's internal control over financial reporting as of December 31, 2011.

b. Auditor's attestation report on internal control over financial reporting

The attestation report of KPMG LLP, the independent registered public accounting firm of Algonquin, on the Company's internal control over financial reporting as of December 31, 2011, is provided herein as Exhibit 99.4 to this annual report on Form 40-F.

c. Changes in internal control over financial reporting

The information provided under the heading "Internal controls over financial reporting" (page 48) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2011, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

AUDIT COMMITTEE FINANCIAL EXPERTS

Algonquin's board of directors has determined that it has three audit committee financial experts serving on its audit committee. Christopher Ball, Kenneth Moore and George Steeves have been determined to be such audit committee financial experts and are independent, as that term is defined by the Toronto Stock Exchange's listing standards applicable to Algonquin. The SEC has indicated that the designation of Christopher Ball, Kenneth Moore and George Steeves as audit committee financial experts does not make any of them an "expert" for any purpose, impose any duties, obligations or liability on Christopher Ball, Kenneth Moore and George Steeves that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee or board of directors.

CODE OF ETHICS

Algonquin has adopted a code of ethics (the "Code of Conduct") that applies to all employees and officers, including its Chief Executive Officer and Chief Financial Officer and Chief Accounting Officer. The Code of Conduct is available without charge to any shareholder upon request to Kelly Castledine, Telephone: (905) 465-4500, E-mail: apif@algonquinpower.com, Algonquin Power & Utilities Corp., 2845 Bristol Circle, Oakville, Ontario, L6H 7H7.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information provided under the heading "Pre-Approval Policies and Procedures" (page 99) in the Annual Information Form for the fiscal year ended December 31, 2011, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein. All audit services, audit-related services, tax services, and other services provided for the year ended December 31, 2011 were pre-approved by the audit committee.

OFF-BALANCE SHEET ARRANGEMENTS

Algonquin is not a party to any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future material effect on its financial condition, results of operations or cash flows.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The information provided under the heading "Contractual Obligations" (page 35) in the Management's Discussion and Analysis for the fiscal year ended December 31, 2011, filed as Exhibit 99.3 to this annual report on Form 40-F, is incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

The information provided under the heading "Audit Committee" (page 98) identifying Algonquin's Audit Committee and confirming the independence of the Audit Committee in the Annual Information Form for the fiscal year ended December 31, 2011, filed as Exhibit 99.1 to this annual report on Form 40-F, is incorporated by reference herein.

CAUTION CONCERNING FORWARD LOOKING STATEMENTS

Certain statements included in this annual report on Form 40-F and the exhibits attached hereto contain forward-looking information within the meaning of the United States Private Securities Litigation Reform Act of 1995 and applicable Canadian securities legislation. These statements reflect the views of Algonquin with respect to future events, based upon assumptions relating to, among others, the performance of Algonquin's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of Algonquin, its future plans and its dividends to shareholders. Statements containing expressions such as "outlook", "believe", "anticipate", "continue", "could", "expect", "may", "will", "project", "estimate", "intend", "plan" and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require Algonquin to make assumptions and involve inherent risks and uncertainties. Algonquin cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that Algonquin's actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the volatility of world financial markets; the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; the state of the Canadian and the United States economies and accompanying business climate as well as those risk factors discussed or referred to in the Management's Discussion and Analysis for the fiscal year ended December 31, 2011, filed as Exhibit 99.3 to this annual report on Form 40-F and the Annual Information Form for the fiscal year ended December 31, 2011, filed as Exhibit 99.1 to this annual report on Form 40-F. Algonquin cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Algonquin reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin believes that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of these dates. Algonquin is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

MINE SAFETY DISCLOSURE

Not applicable.

INTERACTIVE DATA FILE

The required disclosure for the fiscal year ended December 31, 2011 is submitted as Exhibit 101 to this annual report on Form 40-F.

UNDERTAKING

Algonquin undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

Algonquin previously filed with the Commission a written irrevocable consent and power of attorney on Form F-X.

Any change to the name or address of the agent for service of Algonquin shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of Algonquin.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALGONQUIN POWER & UTILITIES CORP.
(Registrant)

Date: March 30, 2012

By: /s/ David Bronicheski
Name: David Bronicheski
Title: Chief Financial Officer

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the year ended December 31, 2011
99.2	Audited Annual Financial Statements for the year ended December 31, 2011
99.3	Management's Discussion & Analysis for the year ended December 31, 2011
99.4	Reports of KPMG LLP, Chartered Accountants, on Financial Statements and Internal Control Over Financial Reporting
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99.6	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
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99.8	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
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Section 2: EX-99.1 (ANNUAL INFORMATION FORM FOR THE YEAR ENDED DECEMBER 31, 2011)

Exhibit 99.1

ALGONQUIN Power & Utilities Corp.

ALGONQUIN POWER & UTILITIES CORP.

ANNUAL INFORMATION FORM

March 30, 2012

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All information contained in this Annual Information Form ("AIF") is presented as at March 30, 2012, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.

1. CORPORATE STRUCTURE

1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. ("**APUC**" or the "**Corporation**") was originally incorporated under the *Canada Business Corporations Act* ("**CBCA**") on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the corporation amended its articles to change its name to Societe Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the corporation, among other things, created a new class of common shares (the "**Common Shares**"), transferred its existing operations to newly formed independent corporation and changed its name to Algonquin Power & Utilities Corp. The head and principal office of APUC is located at 2845 Bristol Circle, Oakville, Ontario, L6H 7H7. APUC contemporaneously acquired all of the outstanding trust units of Algonquin Power Co. (**"APCo"**) (See *General Development of the Business—The Unit Exchange*).

APUC's principal holdings are its trust units ("**Trust Units**") of APCo and shares of Liberty Utilities Co. ("**Liberty Utilities**"). Liberty Utilities' businesses operate under two separately managed regions – Liberty Utilities (South) and Liberty Utilities (West).

Unless the context indicates otherwise, references in this AIF to "**APUC**" include, for reporting purposes only, the direct or indirect subsidiaries of APUC and partnership interests held by APUC and its subsidiaries. Such use of "**APUC**" to refer to these other legal entities and partnership interests does not constitute a waiver by APUC or such entities or partnerships of their separate legal status, for any purpose.

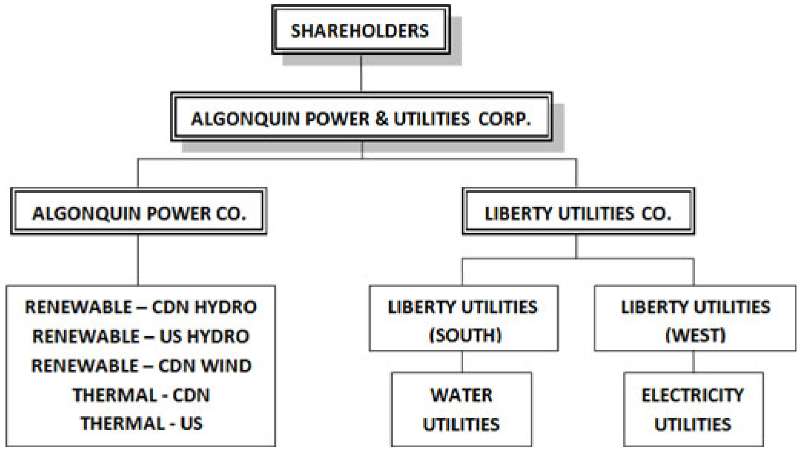
1.2 Intercorporate Relationships

(a) Subsidiaries

The subsidiaries of APUC are grouped into the independent power generation and the utilities businesses. The principal holding for APUC's independent power generation business is an investment in 100% of the issued and outstanding Trust Units of APCo. The principal holding for APUC's utilities business is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp., a federal corporation, which in turn owns all of the issued and outstanding common shares of Liberty Utilities (America) Co., which in turn owns all of the issued and outstanding common shares of Liberty Utilities, a Delaware corporation, which in turn owns and operates the entities within the Liberty Utilities (South) and Liberty Utilities (West) regions. Each of APCo, the Liberty Utilities (South) region and the Liberty Utilities (West) region have their own subsidiaries and ownership chains.

The subsidiaries of APCo include the ownership chains of Algonquin Power Trust ("**APT**"), and Algonquin Power Fund (Canada) Inc. ("**APFC**"). APT's subsidiaries include the ownership chain of Algonquin Power Operating Trust ("**APOT**"), APFC's subsidiaries include the ownership chain of and Algonquin Power Fund (America) Inc. ("**APFA**"). The Liberty Utilities (West) region is currently structured to hold the electric utility assets located in California and acquired January 1, 2011, and the Liberty Utilities (South) region is structured to hold the water distribution and wastewater treatment assets located in the United States.

The following chart summarizes the principal operating subsidiaries of the Corporation and their major lines of business.



The major chains are defined below, including a detailed description of the legal entities that comprise these chains and the facilities they own. Additional information on the facilities is described in Schedules A, B, C and D.

(i) Independent Power Generation Business – APCo Chain

APCo Chain Entities

APCo is the sole beneficiary of APT. APCo also owns Algonquin Holdco Inc., an Ontario corporation, which owns 52.5% of APFC and 62.5% of the issued and outstanding shares of Cornwall Solar Inc.

APT Group

APT forms part of the APCo business unit. APT is an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. APT owns all the Trust Units of APOT.

APT controls the entities that own some of the Canadian hydroelectric facilities, and indirectly owns the energy-from-waste facility (the "**EFW Facility**") located in the Regional Municipality of Peel, Ontario ("**Peel**") by virtue of owning all the Trust Units in KMS Power Income Fund, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997 in accordance with the laws of the Province of Alberta. This trust owns Algonquin Power Energy From Waste Inc. ("**APEFW**"), an Ontario corporation that owns the EFW Facility.

APT also holds interests in certain of APCo's Canadian hydroelectric Facilities. It directly owns the hydroelectric Hydraska Facility and the Arthurville Facility, and owns both the general partnership and the limited partnership interests in Algonquin Power (Campbellford) Limited Partnership ("**Campbellford LP**"), an Ontario limited partnership which operates a 4 megawatt ("**MW**") hydroelectric generation station on the Trent River near Campbellford, Ontario (the "**Campbellford Facility**"). APT also holds a 42% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership (the "**Mont-Laurier Partnership**"), a Québec limited partnership, which owns the Mont-Laurier and the Côte Ste.-Catherine Facilities. APEFW owns the remaining 58% partnership interests, comprised of a 46.5% limited partnership interest and an 11.5% general partnership interest.

APT owns Corporation D'Investissements Éoliennes Algonquin Power ("**Éoliennes**"), a Canadian corporation. Éoliennes indirectly owns St. Ulric Wind Energy Investments L.P. ("**St. Ulrich LP**"), a Québec limited partnership, through its ownership of the limited partnership of St. Ulrich LP and Société en Commandite Algonquin (Éoliennes), a Québec limited partnership, and its direct ownership of the general partner of St. Ulrich LP, named Corporation D'Investissements Éoliens St-Laurent Inc. ("**Corporation St-Laurent**"), a Québec corporation. Corporation St-Laurent is the 50% owner of Saint-Damase Wind Energy Fleur de Lis General Partner Corporation, a federal corporation, which is the general partner of the partnership known as Saint-Damase Wind Energy Fleur de Lis Limited Partnership ("**Fleur de Lis LP**"). Fleur de Lis LP has an interest in the Saint—Damase wind energy project and described below in "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development—Current Development Projects*". St. Ulrich LP owns a 49.995% equity interest in the Fleur de Lis LP, the general partner owns a .02% equity interest, and a non-Algonquin, Saint-Damase party owns the remaining 49.995% equity interest. APT also has an interest in Société Éoliennes Belle- Rivière, société en commandite ("**Belle Rivière**"), a Quebec partnership and the owner of the Val- Éo wind energy project, also described below in "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development—Current Development Projects*". It owns a 25% equity interest in the general partner, 9231-5498 Québec Inc. and it also holds a 24.9975% limited partner interest.

APOT Group

APOT is an unincorporated open ended trust created by an amended and restated trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta.

APOT controls the entities that own the Canadian cogeneration facility located at Brampton, Ontario (the "**BCI Facility**"). The BCI Facility is owned by Brampton Cogeneration Limited Partnership, an Ontario partnership, the partners of which are Brampton Cogeneration Inc. ("**BCI**"), which is the general partner and holds one general partnership unit, and APOT, which owns 100% of the Class A Units (entitled to vote on all matters) and 50% of the Class B Units (vote on only specific matters) in the limited partnership. BCI is an Ontario corporation and is owned by APOT.

APOT controls the entities that own the 104 MW wind facility located at St. Leon, Manitoba (the "**St. Leon Facility**"). The APOT entity that owns the St. Leon Facility is St. Leon Wind Energy LP, an Ontario partnership ("**St. Leon LP**"). It is owned by the general partner, St. Leon Wind Energy GP Inc. ("**St. Leon GP**"), by St. Leon Wind Energy Trust, a Manitoba trust ("**St. Leon Trust**") and by AirSource Power Fund I LP, a Manitoba limited partnership ("**AirSource**"). St.

Leon LP holds a 47.5% interest in APFC. St. Leon LP has issued 100 Class B limited partnership units. Two executives of APUC, Ian Robertson and Christopher Jarratt (the "**Senior Executives**") indirectly each own 18 of the 100 Class B units. St. Leon Trust is owned 100% by AirSource, the limited partner of which is Algonquin (AirSource) Power LP ("**AAP LP**") which holds a 99.99% interest in the limited partnership, and which in turn is owned 99.99% by APOT as limited partner. APOT also controls the general partner of AAP LP, AirSource Power Fund GP Inc, a Canadian corporation. AirSource is also the 100% owner of St. Leon GP. St. Leon GP is a Canadian corporation and St. Leon Trust is a trust created by a declaration of trust dated June 28, 2005 in accordance with the laws of the Province of Manitoba. The AirSource and AAP LP limited partnerships were formed in Manitoba and Ontario, respectively.

APOT is the sole limited partner in St. Leon II Wind Energy LP ("**St. Leon II**"), a Manitoba partnership, the general partner of which is St. Leon II Wind Energy GP Inc. which is also owned by APOT. St. Leon II owns the 16.5 MW wind facility (the "**St. Leon II Facility**"), an expansion of the St. Leon Facility, located at St. Leon, Manitoba.

APOT is the sole limited partner in Red Lily Wind Power II Limited Partnership, a Saskatchewan limited partnership, the general partner of which is Red Lily Wind Power II GP Inc., a Saskatchewan corporation, which is also owned by APOT. APOT also owns Loyalist Wind Project GP Inc., an Ontario corporation, which is the general partner of Loyalist Wind Project LP ("**Loyalist LP**"), an Ontario limited partnership. APUC is the majority limited partner of Loyalist LP, holding a 87.49125% interest. The remaining limited partner of Loyalist LP is an unrelated third party, holding a 12.49875% interest.

APOT has two ownership interests in Alberta. First, it is the beneficial owner of one hydroelectric facility in Alberta (the "**Dickson Dam Facility**"). APOT owns 50% of Valley Power Corp., an Ontario corporation, which holds a 0.0001% limited partnership interest partner in Valley Power LP, an Alberta limited partnership which owns the Alberta biomass facility (the "**Valley Power Facility**"). APOT also directly holds a 49.9995% limited partnership interest in Valley Power LP.

APFC Group

APFC was incorporated in Nova Scotia and it controls the entities that own the majority of the hydroelectric facilities in Canada. APFC owns Algonquin Power (America) Inc., ("**APA**") a Delaware corporation, which is the parent company of APCo's operations in the United States.

In Ontario, APFC directly owns the Burgess and Hurdman Facilities, and has an agreement in place to buy ownership interests in the parties to the joint venture that owns the interests in the Long Sault Rapids Facility. In Québec, APFC directly owns the facilities known as Rawdon, Hydro Snemo, St. Raphael, Belleterre and St. Brigette Facilities. APFC also holds a direct interest in Société Hydro-Donnacona, S.E.N.C. (the "S.E.N.C."), the owner of the Donnacona Facility. The S.E.N.C. is a Québec general partnership, and is owned 99.99% by APFC and 0.01% by Donnacona Holdings Inc., an Ontario corporation 100% owned by APFC. In Newfoundland, APFC holds a 45% partnership interest in the Algonquin Power (Rattlebrook) Partnership, a Newfoundland partnership that owns the Rattlebrook Facility. APFC also 100% owns Algonquin Power Services Canada Inc., a Canadian corporation that provides purchasing services to Canadian APCo entities.

APFC also 1631667 Alberta ULC, an Alberta unlimited liability corporation.

APFA Group

APFA, a Delaware corporation, is owned by APA. APFA owns and controls the U.S. hydroelectric entities, and also controls the entities that own the U.S. thermal cogeneration facilities.

APFA owns Algonquin Power Sanger LLC ("**Sanger LLC**"), a California limited liability company, and Algonquin Power Windsor Locks LLC ("**Windsor LLC**"), a Connecticut limited liability company. These entities own the U.S. cogeneration Sanger and Windsor Locks facilities. Sanger LLC directly owns 100% of Dyna Fibers Inc., a California corporation that operates a hydro-mulch business at the Sanger Facility site. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA indirectly owns numerous hydroelectric facilities through majority interests ranging from 99.7 to 99.99% in the subsidiaries described in this paragraph, with Algonquin Power Fund (America) Holdco Inc. ("**Algonquin Holdco**"), a Delaware corporation owned by APFA, holding the remaining interests. The New York general partnerships Burt Dam Power Company and Hollow Dam Power Company own the Burt Dam and Hollow Dam Facilities, respectively. The Vermont partnership Moretown Hydro Energy Company owns the Moretown Facility. The New Hampshire limited partnerships Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro Associates Limited Partnership and Mine Falls Hydroelectric Limited Partnership own the Gregg Falls, Pembroke and Mine Falls Facilities, respectively.

APFA owns the New Hampshire limited liability company Clement Dam Hydroelectric, LLC which owns the Clement Dam Facility. The Franklin, Beaver Falls and Lakeport Facilities are owned by, respectively, Franklin Power, LLC, a New Hampshire company, Algonquin Power (Beaver Falls) LLC, a Delaware corporation and Lakeport Hydroelectric Corp., a New Hampshire corporation. The Otter Creek and Kings Falls Facilities are owned by Tug Hill Energy, Inc. a New York corporation, which is owned by Court Street Investments, Inc. ("**Court Street**"), a Massachusetts corporation, which in turn is owned 100% by APFA. Court Street also owns CSI Oswego Corp., a Delaware corporation, which is a partner in Oswego Hydro Partners L.P., the Delaware partnership that owns the Phoenix Facility. The other partner in this partnership is Oswego Energy Corp., a Delaware corporation, which is 100% owned by Oswego Power Company, Inc., a Massachusetts corporation, which in turn is 100% owned by APFA. The remaining hydroelectric facilities in the United States are the Great Falls and Lochmere Facilities. The Great Falls Facility is owned by the Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership in which APFA holds a 98% limited partner interest. Great Falls Energy, LLC holds the remaining 2% general partner interest. Great Falls Energy, LLC is a Maryland limited liability company wholly owned by APFA. The Lochmere Facility is owned by the Indiana general partnership HDI Associates I, which is held 0.1% by Algonquin Holdco and 99.9% by APFA.

APFA owns Algonquin Tinker Gen Co. ("**Tinker Gen Co.**") and Algonquin Northern Maine Gen Co. ("**Northern Maine Gen Co.**"), both Wisconsin companies. Tinker Gen Co. is also registered in New Brunswick, and Northern Maine Gen Co. is also registered in Maine. Tinker Gen Co. operates the 36.8MW of electrical generating assets in New Brunswick (the "**Tinker Assets**"), and Northern Maine Gen Co. is the owner of the Caribou and Squa Pan diesel facilities. APFA also 100% owns Algonquin Energy Services Inc., a Delaware corporation ("**AES**") that is also registered in Connecticut, District of Columbia, Maine, Maryland, New Brunswick and Ohio.

AES provides the electrical energy requirements for commercial and industrial customers in northern Maine.

In addition, APFA owns 100% of Algonquin Power Acquisition Inc., a Delaware corporation that was incorporated as an acquisition vehicle for proposed acquisitions by APCo in the United States. It currently has no assets. APFC also 100% owns Algonquin Power Services America LLC, a Delaware corporation that provides purchasing services to U.S. APCo entities.

(ii) Utilities Business

Liberty Utilities (South) Region

Liberty Water Co. ("**Liberty Water**"), a Delaware company, is the parent company of the entities within the Liberty Utilities (South) region. On December 22, 2010, APCo completed a corporate reorganization involving Liberty Water wherein 100% of the issued and outstanding common shares of Liberty Water Co. were transferred from APCo to Liberty Utilities.

Liberty Water indirectly owns the water and wastewater businesses located in Arizona, Texas, Missouri and Illinois, in each case through a 100% wholly-owned subsidiary, with the exception of Northwest Sewer Inc., which it owns directly and the Entrada Del Oro Sewer Company, Inc. ("**Entrada**") which it currently operates and in which it holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition by Liberty Water. All of these 100% wholly-owned subsidiaries (except Northwest Sewer, Inc.) are currently conducting business as "**Liberty Water**"; however the actual legal names of the relevant entities are set out below.

In Arizona, the following Arizona corporations own the following facilities: Bella Vista Water Co., Inc. owns the Bella Vista Facility; Black Mountain Sewer Corporation owns the Black Mountain Facility; Gold Canyon Sewer Company owns the Gold Canyon Facility; Litchfield Park Service Company owns the Litchfield Facility; Northern Sunrise Water Company, Inc. owns the Northern Sunrise Facility; Rio Rico Utilities, Inc. owns the Rio Rico Facility; and Southern Sunrise Water Company, Inc. owns the Southern Sunrise Facility. Northwest Sewer, Inc., an Arizona corporation, has undertaken to a group of developers and homeowner's associations located to the west of Phoenix to apply for a Certificate of Convenience and Necessity and, if successful, operate a wastewater treatment utility in those areas. Entrada, discussed above, is an Arizona corporation, and it owns the beneficial interest in the Entrada Del Oro Facility. In Texas, the following Texas corporations own the following facilities: Tall Timbers Utility Company, Inc. owns the Tall Timbers Facility; Woodmark Utilities, Inc. owns the Woodmark Facility; and Algonquin Water Resources of Texas, LLC, a Texas limited liability company, owns water and water treatment assets at the resorts of Seaside, Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as "Big Eddy"). In Missouri, Algonquin Water Resources of Missouri, LLC, a Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain, Timber Creek resorts, the water utility in Noel, Missouri and a utility in eastern Missouri. In Illinois, Algonquin Water Resources of Illinois, LLC, an Illinois limited liability company, owns assets for the Fox River resort. All water and wastewater utilities are operated under the Liberty Water brand.

In addition, Algonquin Water Services LLC ("**Water Services**") is a company established to manage and operate water distribution and wastewater treatment facilities in Arizona and Texas. It is an Arizona limited liability company owned 99% by New Spring Acquisition Partnership, an Ontario partnership, which in turn is owned 50% by APCo. Algonquin Environmental Services LLC, a Delaware limited liability company owned 100% by Liberty Water, was also established to service various entities.

Liberty Utilities (West) Region

Liberty Energy Utilities Co. ("**Liberty Energy**") is owned by Liberty Utilities and forms the top of the Liberty Utilities (West) region. Liberty Energy is a Delaware corporation. It owns 50.001% of California Pacific Utilities Ventures, LLC, a California limited liability company ("**CPUV**"), which in turn owns California Pacific Electric Company, LLC, a California limited liability company ("**Calpeco**"). Calpeco owns an electricity distribution utility in the Lake Tahoe basin and surrounding areas in California.

Liberty Utilities (East) Region

Liberty Energy also owns Liberty Energy Utilities (New Hampshire) Corp. ("**Liberty Energy (NH)**"), a Delaware corporation registered in New Hampshire. Liberty Energy Utilities (NH) is the named purchaser of the shares of Granite State Electric Company ("**Granite State**") and EnergyNorth Natural Gas Inc. ("**EnergyNorth**") currently owned by of National Grid USA ("**National Grid**").

Liberty Utilities (Central) Region

Liberty Energy also owns Liberty Energy (Midstates) Corp. ("**Liberty Midstates**"), a Missouri corporation. Liberty Midstates is the named purchaser of certain natural gas distribution utility assets in Missouri, Iowa and Illinois (the "**Midwest Gas Utilities**") currently owned by ATMOS Energy Corporation ("**Atmos**").

(iii) Other

Outside of the APCo, Liberty Utilities (South) and Liberty Utilities (West) described above, APUC beneficially owns, directly or indirectly 100% of the following: 3793257 Canada Inc. ("**3793257**"), a holding company incorporated under the CBCA; and Windlectric Inc. ("**Windlectric**"), a federal corporation that is developing various wind projects including one in Saskatchewan and one in Ontario.

APUC also owns the following group of special purpose financing companies, including 90% of Liberty Utilities Finance GP 1 ("**LU GP1**"), a Delaware general partnership. LU GP1 owns 99.9% of Liberty Utilities Finance GP 2 ("**LU GP2**"), a Delaware general partnership. The minority partner in both LU GP1 and LU GP2 is 3793257. LU GP2 owns Liberty Utilities Finance (Canada) ULC, an Alberta unlimited liability corporation which in turn owns Liberty Utilities Finance (US) LLC, a Delaware limited liability company. The above entities were formed as special purpose financing entities to be used in future Liberty Utilities financings.

(b) Other Interests in Energy Related Developments

The Corporation also has notes receivable and equity in companies owning generating facilities as described below. APT owns 25% of the Class B non-voting shares issued by Cochrane Power Corporation, the owner of a combined cycle cogeneration facility located in Cochrane, Ontario. APT also owns 32.4% of the Class B non-voting shares in Kirkland Lake Power Corporation, an entity which burns natural gas and wood waste to generate electricity. APT also owns a 12.1% interest in Tranche A and Tranche B term loan interests issued by Chapais Energie, Société en Commandité ("**Chapais**") which owns a wood waste facility in Chapais, Québec. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais. The loans bear interest at the rate of 10.789% and 4.91%, respectively.

In addition, APUC is entitled to a royalty in the form of cash flows generated by the Long Sault Rapids Facility (the "**LSR Royalty Interest**"). It is also the owner of a 14.14% secured, subordinated note (the "**LSR Subordinate Note**") in the principal amount of $2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc. The LSR Subordinate Note was acquired by APCo on April 17, 1998.

2. GENERAL DEVELOPMENT OF THE BUSINESS

2.1 General

(a) The Unit Exchange

On October 27, 2009, APCo (formerly, Algonquin Power Income Fund) completed a transaction (the "**Unit Exchange**") in which APCo's unitholders exchanged their Trust Units of APCo, on a one-for-one basis, for Common Shares of the Corporation (formerly Hydrogenics Corporation). As a result of the Unit Exchange, APCo itself became a wholly-owned subsidiary of the Corporation and all of the unitholders of APCo became shareholders of the Corporation. The Unit Exchange did not result in any change to the underlying business operations of APCo and accordingly, for accounting purposes, the Corporation is considered a continuation of APCo. Through subsequent internal reorganizations Algonquin Power Income Fund has since changed its name to Algonquin Power Co. and remains a subsidiary of APUC.

(b) Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the independent power and rate regulated utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through dividend growth supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon, APUC strives to deliver annualized per share earnings growth of more than 5% and continued growth in its dividend supported by these increasing cash flows, earnings and additional investment prospects.

APUC's current quarterly dividend to shareholders is $0.07 per share or $0.28 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Additional increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "**Board**") and dividend levels shall be reviewed periodically by the Board in the context of available cash and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC produces stable earnings through a diversified portfolio of renewable power and utility businesses owned and operated by its subsidiary entities. APUC conducts its operations primarily through two businesses: independent power generation and utilities (water, gas and electric). These businesses of APUC are herein referred to as the "**APUC Businesses**".

Independent Power Generation: APCo generates and sells electrical energy through a diverse portfolio of renewable power generation and clean thermal power generation facilities across North America. APCo seeks to deliver continuing growth through development of greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of expansion opportunities within APCo's existing portfolio of independent power facilities. APCo's Renewable Energy division develops and operates APCo's hydroelectric, solar and wind power facilities. APCo's Thermal Energy division develops and operates co-generation, energy-from-waste, and steam production facilities.

The renewable power and thermal energy generation business of APCo is managed with an emphasis on growth through the development of green-field projects and opportunities within APCo's existing portfolio. This is achieved through the Development division which seeks to build on APCo's expertise in the origination of greenfield renewable energy projects, expanding APCo's existing portfolio of renewable and thermal energy assets for further growth, and capitalizing on new opportunities as they arise.

APCo's Renewable Energy division generates and sells electrical energy through a diverse portfolio of clean, renewable power generation and thermal power generation facilities across North America. APCo owns or has interests in hydroelectric facilities operating in Ontario, Québec, Newfoundland, New Brunswick, Alberta, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW.

APCo also owns wind powered generating stations in Manitoba with a combined generation capacity of 120 MW and holds debt securities in a 26 MW wind powered generating station in Saskatchewan.

All of the wind energy facilities' electrical output is sold pursuant to long term power purchase agreements ("**PPA**s") with major utilities which have a weighted average remaining contract life of 20 years. Approximately 80% of the electrical output from the hydroelectric facilities is sold pursuant to long term PPAs with major utilities which have a weighted average remaining contract life of 8.5 years.

APCo owns thermal energy facilities including an energy-from-waste facility in Ontario, diesel generating facilities in Maine and New Brunswick and natural gas-fired cogeneration facilities in each of California, Connecticut, and Ontario. APCo also holds ownership interests in three facilities in Ontario and Quebec. Approximately 67% of the electrical output from the owned thermal facilities is sold pursuant to long term PPAs with major utilities and which have a weighted average remaining contract life of 11 years. Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

Utilities: Liberty Utilities owns and operates utilities through two regions, Liberty Utilities (West) and Liberty Utilities (South). Liberty Utilities (West) is in the electricity distribution, transmission and generation sector. Liberty Utilities (South) is in the water distribution and wastewater treatment sector. The underlying business strategy is to be a leading provider of safe, high quality and reliable utility services while providing stable and predictable earnings from utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings by identifying acquisition opportunities which provides accretive expansion of its business portfolio.

Liberty Utilities (South) provides water and wastewater utility services to approximately 76,000 customers through 21 water distribution and wastewater collection and treatment utility systems located in Arizona, Illinois, Missouri and Texas. These utilities generally operate under rate regulation, overseen by the public utility commissions of the States in which they operate. Detailed information on the water distribution and wastewater utility systems owned and operated by Liberty Utilities is set out in Schedule C.

Liberty Utilities (West) provides local electrical utility services to approximately 47,000 customers in the Lake Tahoe region of California. Detailed information on the electrical utilities system owned and operated by Liberty Utilities (West) is set out in Schedule D.

As the currently committed growth initiatives are completed, additional management regions will be created. The Liberty Utilities (East) region will be formed to deliver electrical and natural gas distribution services upon completion of the acquisitions of Granite State and EnergyNorth. The Liberty Utilities (Central) region will be formed to manage natural gas distribution services upon completion of the Midwest Gas Utilities acquisition.

2.2 Three Year History

The following is a description of the general development of the business of the Corporation over the last three fiscal years.

(a) Fiscal 2009

Corporate

i) **Conversion to a Corporation**

On October 27, 2009, APCo and the Corporation completed the Unit Exchange. See "*General Development of the Business – General – The Unit Exchange*". As part of the Unit Exchange, on October 27, 2009, the trustees of APCo became the directors of APUC.

Also on October 27, 2009, in connection with the Unit Exchange, the debentureholders of APCo exchanged their convertible debentures for convertible debentures of the Corporation or Common Shares. As a result, the debentureholders of APCo became debentureholders and shareholders of the Corporation. See "*Description of Capital Structure – Convertible Debentures*".

ii) **Equity and Convertible Debenture Offering**

On December 2, 2009, APUC completed a public offering of (i) 5,980,000 Common Shares at a price of $3.35 per Common Share for gross proceeds of approximately $20 million and (ii) approximately $55 million principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017 (the "**Series 3 Debentures**" or the "**APUC Debentures**"). The underwriters of the offering also exercised in full an over-allotment option to purchase an additional 897,000 Common Shares and approximately $8.2 million principal amount of Series 3 Debentures resulting in aggregate gross proceeds of approximately $86.2 million. See "*Description of Capital Structure—Convertible Debentures*".

iii) **Internalization of Management**

On December 21, 2009, the Board reached agreement with the shareholders of Algonquin Power Management Inc. ("**APMI**") to internalize all management functions of APCo which were previously provided by APMI. APMI was the manager of APCo and APUC up to December 22, 2009 and two executives of APUC, the Senior Executives, are principals of APMI. APUC acquired the interest previously held by APMI in the management services agreement, with consideration paid in the form of issuance of 1,158,748 Common Shares of APUC.

(b) Fiscal 2010

Corporate

At the annual general meeting on June 23, 2010 (the "**Meeting**"), APUC adopted a Shareholders' Rights Plan (the "**Rights Plan**"). See "*Description of Capital Structure—Shareholders' Rights Plan*".

APCo – Power Generation

i) **Tinker Facility**

On January 12, 2010, APCo completed the acquisition of three hydroelectric generating stations, a 34.5MW hydroelectric generating facility with sufficient reservoir storage capability to move significant amounts of energy from off-peak to on-peak generation located on the Aroostook River near the Town of Perth-Andover, New Brunswick (the "**Tinker Facility**"), a 0.9MW run-of-river hydroelectric generating facility located in Northern Maine (the "**Caribou Facility**") and a 1.4MW run-of-river hydroelectric generating facility located in Northern Maine (the "**Squa Pan Facility**").

APCo also acquired certain thermal generating facilities in Northern Maine and New Brunswick utilized for installed reserve capacity, not continuous generation, and New Brunswick Public Utilities Board regulated transmission lines and interconnections which allow direct and indirect access to multiple electricity markets (Northern Maine ISA, New Brunswick ISO and ISO-NE).

(ii) **AES**

In connection with the acquisition of the Tinker Facility, on February 4, 2010, APCo acquired an energy marketing company which markets the energy generated from the Tinker Facility. AES is managing this business and it is anticipated that the majority of the energy sold by AES will be supplied through generation from the Tinker Assets, based on historical long term average levels of hydroelectric energy generation of these facilities. AES primarily involves standard offer contracts for the supply of energy to commercial and industrial customers in northern Maine, as well as energy purchase obligations with the ISO-NE required to supplement self-generated energy.

AES' business consists of a series of short-term energy supply agreements. These include energy sales to a town in New Brunswick, standard offer service contracts with three local electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine.

(iii) **EFW**

A capital upgrade at the EFW Facility was completed in July 2010 and has resulted in higher throughput and lower operating costs per tonne at the Facility in 2011 as compared to periods prior to the upgrade.

Liberty Utilities

(i) **California Utility**

On April 23, 2009, APUC announced plans to co-acquire an electrical generation and regulated distribution utility (the "**California Utility**") in partnership with Emera, pursuant to the asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 (the "**Purchase Agreement**").

On January 1, 2011, APUC, in partnership with Emera, completed the transaction and acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, Calpeco.

For a more detailed discussion of this acquisition, see "*General Development of the Business—Significant Acquisitions – 2011 – Liberty Utilities – California Utility Acquisition*".

(ii) **New Hampshire Utility**

On December 9, 2010, APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State, a regulated electric distribution utility, and EnergyNorth, a regulated natural gas distribution utility from National Grid, as outlined in the share purchase agreements by and between National Grid and Liberty Energy entered into on December 8, 2010 and amended and restated on January 11, 2011 (the "**Purchase Agreements**").

For a more detailed discussion of this acquisition, see "*General Development of the Business—Significant Acquisitions – 2011: New Hampshire Utility Acquisition*".

(iii) **Liberty Utilities (South) – Rate Cases**

Liberty Utilities (South) had ongoing rate cases at a number of its utilities which were processed throughout 2010. See "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater – Rate Cases—General*" for further discussion of the status of these rate cases. During the year ended December 31, 2010, Liberty Utilities (South) completed rate case proceedings at nine utilities in Arizona and Texas which on an annualized basis were expected to contribute an additional U.S. $10.2 million in revenue in the Liberty Utilities (South) region. As these rate cases were settled at various times throughout the year ended December 31, 2010, approximately U.S. $2.3 million of the overall annualized revenue increase from rate cases completed in Arizona and Texas was achieved in the year. One additional rate case requesting U.S. $1.1 million in annual revenue requirement was concluded in the first quarter of 2011.

(iv) **Liberty Utilities (West) – Senior Debt Financing**

The acquisition of the California Utility was funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility entered into on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors, and is an obligation solely of the California Utility. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

(v) **Liberty Utilities (South) – Senior Debt Financing**

On December 22, 2010, Liberty Water completed a private placement financing of senior unsecured 5.6% notes for gross proceeds of approximately U.S. $50 million. The private placement is a senior unsecured private placement with U.S. institutional investors, and is an obligation solely of Liberty Water. The notes have a 10 year term bear interest until June 2016 when annual principal repayments of U.S. $5.0 million annually commence. The funds were used to reduce outstanding indebtedness under APCo's senior credit facility.

(c) Fiscal 2011

Corporate

(i) **Strengthened Liquidity—Issuance of $95.3 million of Common Shares**

On October 27, 2011, APUC completed a public offering (the "**Offering**") of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued an aggregate of 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

The net proceeds of the Offering will be used to fund a portion of the investment related to previously announced growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

(ii) **Strengthened Balance Sheet—Conversion of Convertible Debentures to Equity**

Effective May 16, 2011 ("**Redemption Date**"), APUC redeemed $2.1 million, all of the remaining issued and outstanding principal amount, of Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 (the "**Series 1A Debentures**") and issued 430,666 Common Shares of APUC upon the redemption. Between January 1, 2011 and the Redemption Date, $60.339 million principal amount of Series 1A Debentures were converted by debentureholders into 14,788,976 shares of APUC.

(iii) **Strategic Investment Agreement with Emera**

On April 29, 2011, APUC entered into a strategic investment agreement (the "**Strategic Agreement**") with Emera which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Agreement builds on the strategic partnership effectively established between the two companies in April 2009.

The Strategic Agreement outlines "areas of pursuit" for each of APUC and Emera. For APUC, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. For Emera, these include investment opportunities related to regulated renewable projects within its service territories and large electric utilities. These "areas of pursuit" are intended to represent investment areas in which there is potential overlap between Algonquin and Emera and are not exhaustive of either company's business focus and do not limit in any way the activities which either APUC or Emera can undertake. Each of APUC or Emera are free to undertake independently investments within their own "area of pursuit" and outside the other party's "areas of pursuit". Under the Strategic Agreement, to the extent either APUC or Emera encounter opportunities which fall within the other's "areas of pursuit", they are committed to work with the other party in the development of such investment opportunities.

As an element of the Strategic Agreement, Emera's allowed common equity interest in APUC will be increased from 15% to 25%. The Strategic Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

APCo—Power Generation

(i) **AES Standard Offer Contract**

In 2011, AES entered into a three year contract with Maine Public Service Company ("**MPS**"), a regulated electric transmission and distribution utility serving approximately 36,000 electricity customer accounts in Northern Maine starting March 1, 2011 to provide standard offer service to multiple commercial and industrial customers in Northern Maine. The anticipated customer load associated with the standard offer service is approximately 135,000 MW-hrs.

(ii) **Windsor Locks Repowering**

The Windsor Locks facility is a 56 MW natural gas powered electrical and steam energy generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to an energy services agreement ("**ESA**").

APCo has entered into an agreement to extend the ESA with Ahlstrom from 2017 to 2027. As a result, APCo is in the process of acquiring a new combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is in construction with commercial operation expected in July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("**ITC**") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

For a more detailed discussion of this, see "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal— Cogeneration – Material Facilities – Windsor Locks Facility*".

(iii) **APCo Senior Unsecured Debentures**

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the "**Senior Unsecured Debentures**") by way of private placement. The net proceeds from the Senior Unsecured Debentures were used to repay the outstanding senior project debt financing related to the St. Leon facility (the "**AirSource Senior Debt**") and to reduce amounts outstanding under APCo's senior revolving credit facility. The Senior Unsecured Debentures mature on July 25, 2018, and bear interest at a rate of 5.50% per annum, calculated semi-annually payable on January 25 and July 25 each year, commencing on January 25, 2012.

(iv) **APCo Facility Renewal**

On January 14, 2011, APCo received commitments from a syndicate of Canadian banks for a new $142 million credit facility with a three year term (the "**APCo Facility**"). The APCo Facility matures on February 14, 2014. APCo reduced the amount of the APCo Facility to $120 million following the completion of the Senior Unsecured Debenture private placement by APCo in July 2011.

As at March 30, 2012, APCo had used the APCo Facility to post (i) a letter of credit in the approximate amount of U.S. $19.5 million in respect of the Sanger Facility; (ii) a $1.0 million letter of credit in respect of the Dickson Dam Facility; (iii) letters of credit for the EFW Facility totalling $5.4 million; (iv) letters of credit pursuant to the BCI Facility totalling $2.4 million; (v) letters of credit in connection with the St. Leon Facility totalling $1.8 million; (vi) letters of credit in connection with the Long Sault Rapids Facility totalling $1.2 million; (vii) letters of credit in connection with the St. Leon II Wind Project totalling $3.4 million; (viii) letters of credit in connection with the Cornwall Solar Project totalling $0.5 million; (ix) letters of credit in connection with the various wind development projects totalling $6.9 million; and (viii) various other letters of credit required by APCo entities totalling $0.3 million.

Liberty Utilities

(i) **California Utility**

On April 29, 2011, pursuant to the Strategic Agreement, Emera and APUC agreed to the general terms by which Emera would sell its 49.999% direct ownership in the California Utility to APUC, with closing of such transaction subject to, among other things, execution of a definitive purchase agreement and regulatory approval. On September 12, 2011, Emera US Holdings Inc., a subsidiary of Emera through which it holds its interest in the California Utility, entered into a definitive purchase agreement with Liberty Utilities. In connection with this transaction, Emera entered into a subscription agreement with APUC dated September 12, 2011 (the "**Subscription Agreement (Calpeco)"**), pursuant to which Emera subscribed for an aggregate of 8,211,000 subscription receipts from APUC at a price of $4.72 per subscription receipt. Payment for these subscription receipts was satisfied by delivery by Emera of two non-interest bearing promissory notes, one in the amount of $22,608,800 and one in the amount of $16,147,120. The proceeds of this subscription receipt transaction will be used to fund the acquisition by Liberty Utilities of Emera US Holdings Inc.'s interest in the California Utility. 4,790,000 subscription receipts will convert into APUC shares on a one-for-one basis following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012), at which time the $22,608,800 promissory note delivered by Emera to APUC to satisfy the subscription price of the first tranche of subscription receipts become due and payable. The remaining 3,421,000 subscription receipts will convert into APUC shares on a one-for-one basis following completion of the California Utility's first rate case, expected to be completed in early 2013, at which time the $16,147,120 promissory note delivered by Emera to APUC to satisfy the subscription price of the second tranche of subscription receipts become due and payable. In the event of termination of the Subscription Agreement (Calpeco), the promissory notes will be returned to Emera for cancellation, the subscription receipts will be returned to APUC for cancellation, and the parties will have no further obligations under the Subscription Agreement (Calpeco).

2.3 Recent Developments—2012

Corporate

(i) Strengthened Balance Sheet—Conversion of Convertible Debentures to Equity

Effective February 24, 2012 ("**Series 2A Redemption Date**"), APUC redeemed $57.0 million, representing the remaining issued and outstanding principal amount, of 6.35% convertible unsecured subordinated debentures due November 30, 2016 (the "**Series 2A Debentures**") at a price of $1,000 per debenture by issuing and delivering an aggregate of 9,836,520 APUC shares. Between January 1, 2012 and the Series 2A Redemption Date, $2.9 million principal amount of Series 2A Debentures were converted by debentureholders into 485,998 shares of APUC.

(ii) Business Associations with APMI and Senior Executives.

There have been a number of business relationships between the Senior Executives (being Ian Robertson and Chris Jarratt), APMI and related affiliates (collectively the "**Parties**") and APUC. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. In 2011, the Board conducted a process to review all of the remaining business associations with the Parties in order to reduce, streamline and simplify these relationships. The Board formed a special committee and engaged independent consultants to assist with this process.

The co-owned assets and remaining business associations as at December 31, 2011 are listed below. Subsequent to December 31, 2011, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "**Agreement**"). A more detailed description of the Agreement has been set out below in Settlement of Other Business Associations.

Rattlebrook hydroelectric generating facility

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 27.5% by Senior Executives and the remaining percentage by third parties. This relationship was addressed pursuant to the Agreement. See Settlement of Other Business Associations below for more details.

St. Leon wind power generating facility

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives. APUC and the Class B unit holders have simplified the relationship by amalgamating the previous partnership agreement and two amending agreements into an amended and restated agreement. In addition, APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

Brampton Cogeneration Inc.

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $100 in relation to the development of this project. In 2008, APUC accrued $100 as an estimate of the final fee owed to APMI. This relationship and corresponding liability was addressed pursuant to the Agreement.

Long Sault Rapids hydroelectric generating facility

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the equity cash flows commencing in 2014. This relationship was addressed pursuant to the Agreement.

Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2011, $279 of the advance remained. The Board has undertaken an independent review of the relationship and believes that continuing the original arrangement is beneficial to the company. The current arrangement is expected to end in approximately 2016 when the advance will be fully utilized.

Office lease

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The original lease was due to expire in December 31, 2012. Effective April 1, 2011, a subsidiary of APUC leased its head office facilities from a third party in a new stand alone building immediately adjacent to APUC's head office for a term of 5 years ending December 31, 2015 with an additional 5 year renewal option. APUC has amended its lease at its existing premises to be co-terminus with its subsidiary's new lease. The majority of terms in the amended lease are identical. Based on a review of the real estate leasing market in the fall of 2010, APUC believes the amended lease is on terms equivalent to fair market value for prime office space of similar size and quality.

Operations services

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by an affiliate of APMI. APUC and the APMI affiliate had agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit. APUC agreed to provide supervisory management on a cost recovery basis for one of the facilities until December 31, 2012 to provide sufficient time for APMI to make alternative arrangements to manage the facility.

Sanger construction management

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI. This liability was settled pursuant to the Agreement.

Clean Power Income Fund

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of December 31, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet. This liability was settled pursuant to the Agreement.

Red Lily I

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. APUC has acquired APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility. This liability was settled pursuant to the Agreement.

Trafalgar

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("**Trafalgar**"). In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar was previously awarded a U.S. $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was reached in 2004 between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal fees, third party costs and other liabilities with the proceeds from the lawsuits being shared after reimbursement of legal fees, third party costs and other liabilities. The Board has determined that any proceeds from the lawsuit will be shared between APMI and APUC proportionally to the quantum of such costs funded by each party. The Second Circuit Court of Appeals dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

Settlement of Other Business Associations.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including Sanger repowering project, the offer to acquire Clean Power Income Fund and the development of the Red Lily I wind project.

The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the Rattlebrook and Long Sault Rapids facilities, provide a valuation of these assets and to provide advice to APUC in respect thereof.

APCo—Power Generation

(i) **Acquisition of U.S. Wind Farms**

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind power projects in the United States (the "**Projects**") from Gamesa Corporación Tecnológica, S.A. ("**Gamesa**") for total consideration of approximately U.S. $888 million.

APCo will contribute U.S. $269 million to partially fund the acquisition of the Projects; tax assisted equity investors will contribute U.S. $360 million. APCo intends to finance its investment with approximately 45% debt and 55% equity. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissioning near the end of 2012.

The Projects consist of four facilities, Minonk (200MW), Senate (150MW), Pocahontas Prairie (80MW) and Sandy Ridge (50MW) located in the states of Illinois, Texas, Iowa and Pennsylvania, respectively. Pocahontas Prairie and Sandy Ridge have recently reached their commercial operation dates ("**COD**") in February 2012, and Senate and Minonk are in construction with COD anticipated in Q4 2012. Total annual energy production from the four facilities is expected to be 1,644 GW-hrs per year. The Projects are comprised of 240 Gamesa

G9X-2.0 MW wind turbines. The Projects each have entered into a 20 year contract with Gamesa to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities.

The Projects have long term, fixed price power sales contracts (the "**Power Sales Contracts**") with a weighted average life of 11.8 years (Minonk and Sandy Ridge 10 years, Senate 15 years). Approximately 73% of energy revenues would be earned under the Power Sales Contracts. All energy produced in excess of that sold under the Power Sales Contracts, together with ancillary services including capacity and renewable energy credits, will be sold into the energy markets in which the facilities are located.

(ii) **St. Leon Facility Expansion**

On July 18, 2011, APCo entered into a 25-year PPA with Manitoba Hydro in respect of the St. Leon II Facility located in the Province of Manitoba.

Construction of this project commenced on August 30, 2011. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The total capital cost of the project is expected to be $29.5 million. The project is expected to achieve commercial operation early in the second quarter of 2012 with revenues in the first full year of operating following commissioning expected to be $3.8 million.

(iii) **New Projects under Development**

As of March 7, 2012, APCo had been awarded or acquired interests in 7 major power development projects that significantly expands the company's electrical generation capacity by 350 MW and once completed will increase the company's annual generation production by over 1,200 GWhrs. Each project has a PPA with a Canadian provincial utility and has a contract length of 20 years or longer.

The following summarizes a number of projects under development and for which PPA's have been awarded since December 2010.

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island	Ontario	75	$230.0	2014	25	247.0
Morse Wind [1]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase	Quebec	24	$70.0	2013	20	86.0
Val Eo	Quebec	24	$70.0	2015	20	66.0
St. Leon II	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

[1] The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011.

For a more detailed discussion of these projects, see "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development – Current Development Projects*".

Liberty Utilities

i) ***New Hampshire Utility Acquisition update***

On December 9, 2010 Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State and EnergyNorth. For a more detailed discussion of this acquisition, see "*General Development of the Business – Significant Acquisitions – 2011 – New Hampshire Utility Acquisition*".

The closing of the transaction is subject to approval by the New Hampshire Public Utilities Commission ("**NHPUC**"). Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing early in the second quarter of 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of the second quarter of 2012.

ii) ***Midwest Utility Acquisition update***

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the "**Midwest Gas Utilities**") located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million. For a more detailed discussion of this acquisition, see "*General Development of the Business – Significant Acquisitions – 2011 – Midwest Gas Utilities Acquisition*".

The closing of the transaction is subject to approval by the Missouri Public Service Commission ("**MPSC**"), Iowa Utilities Board ("**IUB**"), and Illinois Commerce Commission ("**ICC**"). Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the Company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in the second quarter of 2012. Management expects closing to occur towards the end of the second quarter of 2012.

iii) ***Liberty Utilities Credit Facility***

On January 19, 2012, Liberty Utilities entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the "**Liberty Facility**") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility can be increased to accommodate future working capital needs or other requirements.

As at March 25, 2012, Liberty Utilities had used the Liberty Facility to post (i) four letters of credit in the approximate amount of U.S. $1.2 million in respect of Liberty Utilities (South).

2.4 Significant Acquisitions and Investments—2011

APCo—Power Generation

i) **Cornwall Solar**

APCo entered into a share purchase agreement with EffiSolar Energy Corporation ("**EffiSolar**") to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the Feed-in-Tariff ("**FIT**") pipeline have submitted FIT applications for an additional 100MWac.

For a more detailed discussion of this acquisition, see "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development—Current Development Projects*".

ii) **Red Lily Wind Project**

On February 28, 2011 the 26.4 MW wind generation facility in southeastern Saskatchewan ("**Red Lily I**") commenced commercial operation under the PPA. APUC's investment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011.

Project construction costs at Red Lily I were approximately $71.2 million. APUC and APCo earned $1.6 million in interest income and $1.9 million in other payments and fees in 2011, representing approximately 75% of the expected net cash flows from Red Lily I. APUC has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest in Red Lily I, exercisable in February 2016.

Liberty Utilities

i) **California Utility Acquisition**

On January 1, 2011, APUC, in partnership with Emera, completed the transaction and acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments.

On April 23, 2009, APUC agreed to co-acquire an electrical generation and regulated distribution utility in partnership with Emera. APUC and Emera would own 50.001% and 49.999%, respectively, of CPUV, which owns 100% of Calpeco. Calpeco was formed to acquire the California-based electricity distribution and related generation assets of NV Energy for the purchase price of approximately US $132 million, subject to certain working capital and other closing adjustments, as outlined in the Purchase Agreement.

In October 2009, an application was filed with the CPUC requesting approval of the transaction in which NV Energy had agreed to sell its California electric distribution and generation assets to Calpeco. The transaction was subject to State and Federal regulatory approval. On January 1, 2011, following receipt of all U.S. State and Federal regulatory approvals, Calpeco acquired the assets comprising the California Utility. The California Utility provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region.

As an element of the California Utility partnership, pursuant to a subscription and unitholder agreement dated April 22, 2009 (the "**Subscription Agreement**"), Emera agreed to a conditional treasury subscription of approximately 8.5 million Trust Units of APCo at a price of $3.25 per unit. Subsequent to the completion of the Unit Exchange, the Subscription Agreement was amended to reflect a subscription of Common Shares rather than Trust Units of Algonquin. Upon closing, Emera exchanged these subscription receipts into 8.523 million Common Shares at a purchase price of $3.25 per Common Share. The proceeds of the subscription receipts were utilized to fund Liberty Utilities (West)'s ownership share of the cost of acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured private debt placement at the utility entered into on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors, and is solely an obligation of the California Utility. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

ii) **New Hampshire Utility Acquisition**

On December 9, 2010, APUC announced that Liberty Energy had entered into agreements to acquire all issued and outstanding shares of Granite State, a regulated electric distribution utility, and EnergyNorth, a regulated natural gas distribution utility from National Grid for total consideration of U.S. $285.0 million, subject to certain working capital and other closing adjustments, as outlined in the NH Purchase Agreements.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively.

Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in 2012. Financing of the acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Energy is targeting a capital structure with not more than 50% debt to total capital, consistent with investment grade utilities.

As an element of the EnergyNorth and Granite State acquisitions and pursuant to a subscription agreement dated March 25, 2011 (the "**Subscription Agreement (National Grid)**"), Emera subscribed for 12,000,000 subscription receipts of APUC at a price of $5.00 per subscription receipts. Payment for the subscription receipts was satisfied by delivery by Emera of a non-interest bearing promissory note in the amount of $60,000,000. Upon satisfaction of the conditions precedent to the closing of the National Grid transactions (other than payment of the purchase price), including the receipt of all necessary regulatory approvals, the promissory note will become due and payable and the rights evidenced by the subscription receipts will be deemed to have been satisfied by the delivery of Common Shares from APUC on a one-for-one basis, subject to customary anti-dilution adjustments. Delivery of Common Shares of APUC upon conversion of the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. In the event of termination of the Subscription Agreement (National Grid), the promissory note will be returned to Emera for cancellation, the subscription receipts will be returned to APUC for cancellation, and the parties will have no further obligations under the Subscription Agreement (National Grid).

iii) **Midwest Gas Utility Acquisition**

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the "**Midwest Gas Utilities**") located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments, as outlined in the share purchase agreements by and between Atmos and Liberty Midstates entered into on May 12, 2011 (the "**Midwest Purchase Agreements**").

Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million.

3. DESCRIPTION OF THE BUSINESS

3.1 General Description of the Regulatory Regimes in which the Business Operates.

(a) Power Generation Regulatory Regimes

(i) Canada

In Canada, the provinces have legislative authority over the supply of energy. The majority of the electrical supply within the Canadian provinces is provided by large Crown corporations such as Ontario Power Generation Inc. and Hydro-Québec or smaller, investor-owned utilities. These large utilities have been primarily responsible for the generation, transmission and distribution of electricity.

"**Green Power**" is considered electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. Green Power includes technologies such as small hydroelectric (generally defined as facilities of less than 20 MW in capacity), bioenergy, landfill gas, wind and photovoltaic technologies. Since 1997, both the federal and provincial governments in Canada have provided various incentives to stimulate the production of Green Power in Canada. The incentives have varied from direct subsidies, to tax credits to higher than market rates for electricity generated from renewable energy sources.

In 2007, the Canadian Federal government established a new Renewable Power Production Incentive program ("**RPPI**") called "ecoEnergy for Renewable Power" that was created to stimulate up to 14.3 terawatt hours of other new renewable energy. The RPPI provides for an incentive of $10 per MW-Hr of production for the first ten years of operations for eligible projects commissioned after April 1, 2007 and before March 31, 2011. Eligible technologies include waterpower, advanced, innovative and highly efficient biomass, combustion technologies using biogas and other renewable technologies. Although no new contribution agreements will be signed after March 31, 2011, signed agreements will continue to receive payments as outlined in contribution agreements up to March 31, 2021

(ii) **United States**

The power generation industry in the United States is regulated by the United States Federal Energy Regulatory Commission ("**FERC**") under the U.S. Federal Power Act ("FPA") and Public Utilities Regulatory Policies Act ("**PURPA**").

a. Rate Regulation

While Qualifying Facilities ("**QFs**"), which comprise the majority of APCo's US facilities, were previously exempt from rate regulation under the FPA, due to changes in PURPA, QFs are now subject to rate regulation under Section 205 and 206 of the FPA, subject to certain exceptions. Sales of energy or capacity made by QFs 20 MW or smaller, or made pursuant to a contract executed on or before March 4, 2006, or made pursuant to a state regulatory authority's implementation of PURPA are exempt from regulation under sections 205 and 206 of the FPA. All relevant APCo facilities had PPAs in place predating March 4, 2006, and as such have not been impacted.

The APCo facilities that are not QFs have market-based rate authority under the FPA and thus are subject to less regulation than cost of service based entities.

b. PURPA Regulatory Structure

The purpose of PURPA is to encourage the development of small independent power production. To accomplish this, FERC requires electric utilities to purchase energy and capacity from QFs at the utility's avoided cost. "**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator.

As a result of the Energy Policy Act of 2005, electric utilities are no longer required to purchase energy or capacity from a QF if the utility can prove the QF has nondiscriminatory access to:

(1)(i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and

(ii) Wholesale markets for long-term sales of capacity and electric energy; or

(2)(i) Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and

(ii) Competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(3) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in paragraphs (a)(1) and (a)(2) of this section.

There is a rebuttable presumption that QFs have non-discriminatory access to the market if they are eligible for service under a Commission-approved open access transmission tariff ("**OATT**") and are subject to Commission-approved interconnection rules. There is, however, also a rebuttable presumption that QFs with capacity at or below 20 MWs do not have non-discriminatory access to the market. Because all the APCo QFs have 20 MWs or less of capacity or are on a long term PPA, they qualify for this rebuttable presumption.

(b) Water Utility Services Regulatory Regimes

(i) United States Water Services Industry

Investor-owned utilities are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%.

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is provided a service territory defined by a Certificate of Convenience and Necessity which imposes an exclusive right and duty to serve in the service territory. A Certificate of Convenience and Necessity is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

(c) Electrical Utility Services Regulatory Regimes

(i) United States Electric Services Industry

Investor-owned electricity utilities are subject to regulation by the public utility commissions of the States in which they operate. The respective public utility commissions typically have jurisdiction over rates, services, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%.

Generally, electricity providers in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the electric services company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

The electricity industry remains perhaps the most highly regulated in the United States. The industry is regulated under strict standards at multiple levels—federal, state and sometimes local. Under the Federal Power Act, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability. This oversight also includes cost-of-service regulation to establish rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs in order to determine the revenue requirement upon which each utility's customer rates are set. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure reliable service and adequate supplies of electricity together with financial security, transparency in the rate setting process and reasonable prices.

3.2 Production Method, Principal Markets, Distribution Methods and Material Facilities

(a) Power Generation: Renewable—Hydroelectric

(i) Production Method

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as "head"), as well as to provide sufficient depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a headpond.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner. The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

(ii) Principal Markets and Distribution Methods

The principal markets in which APCo operates in Canada are Alberta, Ontario, New Brunswick and Québec. In the US, the principal markets are Maine, New York State and New Hampshire. The majority of generated hydroelectricity is conveyed from the relevant APCo facility to the purchasers under the terms of long term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser. A summary of the PPAs for APCo's Renewable Energy division is set out in Schedule A.

(1) <u>Alberta</u>

The electrical power industry in Alberta is regulated by the *Electric Utilities Act (Alberta)*(the "**EUA**"). The Power Pool of Alberta (the "**Power Pool**") was established under the EUA to provide a competitive, real-time spot market for electric energy. The Power Pool is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the Power Pool.

The EUA has also established the Alberta Electric System Operator (the "**AESO**") to operate and manage the Power Pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy in Alberta . The AESO is governed by an independent board appointed by the Alberta Minister of Energy.

The AESO spot market, or pool price, is determined by market forces. The AESO accepts offers to sell power and bids to buy power through its Energy Trading System. The AESO then dispatches electricity in accordance with an economic merit order based on the lowest cost offers to supply demand in real time. All energy traded through the Power Pool is financially settled each hour at a single spot market price.

Three categories of sellers are eligible to offer and sell electricity through the Power Pool: marketers, importers and independent power producers. There are also three categories of eligible purchasers who may bid to acquire electricity from the Power Pool: retailers, direct access customers and exporters.

(2) Ontario

The Ontario government develops the regulatory framework for wholesale and retail competition through the Ontario Energy Board (the "**OEB**"). While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

The Ontario Electricity Financial Corporation ("**OEFC**") holds all rights, obligations and liabilities under, and purchases the energy generated by the Ontario facilities in which APCo has an interest pursuant to, the existing contracts. APCo has also received a licence to generate from the OEB as required by the *Ontario Energy Board Act, 1998* (Ontario).

(3) New Brunswick and Northern Maine

In 2003 the New Brunswick government amended the provincial *Electricity Act (New Brunswick)* (the "**Electricity Act**") which resulted in the start of competition in the generation business.

As a result of the Electricity Act, which took effect in October of 2004, New Brunswick Power Corporation ("**NB Power**") was divided into separate businesses. The distribution and customer service division of NB Power now functions as a regulated monopoly and serves all the residential and industrial power consumers in the province, with the exception of those in Saint John, Edmundston and Perth-Andover which are served by Saint John Energy, City of Edmundston Electric and the Perth-Andover Electric Light Commission, respectively.

One of the separate entities created by the Electricity Act is the New Brunswick System Operator ("**NBSO**"), an independent not-for-profit statutory corporation. NBSO is responsible for the adequacy and reliability of the integrated electricity system, and for facilitating the development and operation of the New Brunswick electricity market. These responsibilities take the form of operation of the NBSO-controlled grid and administration of the Open Access Transmission Tariff and the New Brunswick Electricity Market Rules.

The NBSO is the Balancing Authority for New Brunswick, Prince Edward Island, and Northern Maine, and the Transmission Provider for New Brunswick. NBSO provides load following and regulation service to the system in order to supply customer load in the province while maintaining scheduled flows on interconnections within established limits. NBSO is the authority responsible for the operation of the Bulk Power System in New Brunswick, Nova Scotia, Prince Edward Island, and a portion of northeastern Maine.

(4) Québec

Similar to Ontario, the Québec government develops the regulatory framework for wholesale and retail competition. Since 1991 Hydro-Québec has procured some of its power requirements from private producers on terms and rates negotiated with each producer. The province continues to introduce various programs to stimulate renewable power from hydroelectric and wind powered facilities as well as cogeneration plants fuelled by biomass and natural gas.

In April 2002, the Québec government adopted the *Dam Safety Act (Quebec)* and corresponding regulations. The *Dam Safety Act (Quebec)* imposes a series of safety measures governing the construction, alteration and operation of high-capacity dams. It requires dam owners to maintain their facilities in good repair and monitor their hydraulic works. As a result of this legislation, APCo's Renewable Energy division was required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased by APCo within the Province of Québec.

APCo has spent approximately $1.5 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APCo currently estimates further capital expenditures of approximately $16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

	Total	2012	2013	2014	2015
Estimated future Bill C-93 Capital Expenditures	**16,900**	1,100	5,300	7,700	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities.

- The dam safety evaluation for the Mont Laurier facility was completed in 2008 and APCo's proposed remediation plan has now been accepted by the Quebec government. APCo has been performing engineering and permitting since 2010 and received the Certificate of Authorization from the Quebec government in November 2011. APCo anticipates completing the on-site remediation work in 2012.
- In respect of the Donnacona facility, APCo completed the dam safety evaluation in 2007 and has been investigating alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates. APCo anticipates completing the engineering in 2012 and performing the remedial work in 2013 and 2014.
- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCO will review the results of the condition assessment and finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo has been corresponding with the Quebec government and other stakeholders about these options since 2007. APCo anticipates completion of any required work on these dams by 2015.
- The dam remediation work related to Chute Ford will be completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013. No dam remediation work is required at the Arthurville, Hydraska, and Ste-Brigitte facilities.
- The dam remediation work related to the Rawdon facility was completed in 2011.

In addition to the C-93 related dam remediation work, APCo has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

(iii) Material Facilities

(1) Long Sault Rapids Facility

The Long Sault Rapids Facility is an 18 MW hydroelectric generating facility located on the Abitibi River, 19 kilometres north of the Town of Cochrane, in northern Ontario. The Facility was commissioned on April 1, 1998.

The Facility was developed by a joint venture between Algonquin Power (Long Sault) Partnership and N-R Power Partnership. The Facility is owned by the co-owning joint venturers (the "**Co-Owners**") as tenants-in-common and not as joint tenants, with the co-owners each having an undivided 50% interest in the facility. The partners in the Algonquin Power (Long Sault) Partnership, Algonquin Power (Long Sault) Corporation Inc. and Energy Acquisition (Long Sault) Ltd., are wholly-owned subsidiaries of Algonquin Power Corporation Inc. ("**APC**"), a corporation affiliated with APMI. The partners in the N-R Power Partnership are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There are two non-recourse loans outstanding which are secured against the facility and the Co-Owners' interest therein (see "*Hydroelectric – Long Sault Rapids Facility—Credit Agreements*" below).

APCo's interest in the Facility was acquired by way of subscribing to two notes from the original developers. The notes receivable have a face value of approximately $17 million and bear interest at 9%. APCo earns interest income on the notes and is entitled to 100% of any incremental after tax cash flows from the facility up to 2013, 65% of any incremental after tax cash flows from 2014 to 2027 and 58% of any incremental after tax cash flows thereafter. APCo also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

The Facility is a "**run of the river**" facility, which means there is a continuous discharge of water from the facility with no storage and release of water. The powerhouse is an integrated structure, housing four 4,500 kilowatt pit turbine generating units.

i) PPA

Pursuant to the terms of the PPA, the Co-Owners sell power produced by the Facility exclusively to OEFC. The PPA terminates 50 years from the commercial in-service date, April 1, 1998, and may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. The rates are escalated annually based on an index figure tied to the greater of OEFC's Total Market Cost index (a minimum of 1% to a maximum of 8%).

The Co-Owners receive a monthly capacity payment when the Facility delivers an average of at least 1,800 kilowatts of power delivered to the delivery point in each fifteen minute interval to OEFC during at least 85% or more of the On-peak period fifteen minute intervals for that month. The "**On-peak**" period is between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays, and "**Off-peak**" is the other remaining hours. Monthly energy in excess of 115% of target generation is subject to an additional payment.

ii) Waterpower Lease

The waterpower lease with the Province of Ontario in respect of the dam site expires in 2048. The lease provides for an annual land rental and an annual water rental charge. The annual water rental charge commenced in January 2008.

iii) Co-Owners Agreement and Management Agreement

The Co-Owners have entered into an agreement concerning, among other things, their holding of undivided interests in the facility. Upon the occurrence of specified events of default, the non-defaulting Co-Owner may purchase the defaulting Co-Owner's interest for 90% of the fair market value. The Co-Owners have entered into a management agreement with NR-Algonquin Energy Management Inc. to manage the Facility on their behalf for nominal consideration.

iv) Credit Agreements

There is an outstanding senior loan against the Facility in the amount of $39.0 million at December 31, 2011. The loan was provided by a syndicate comprised of The Clarica Life Insurance Company ("**Clarica**"), The Canada Life Assurance Company and the Maritime Life Assurance Company. Clarica acts as agent for the syndicate. The loan has a term of 30 years, maturing in January 2028 and bears interest at an interest rate of 10.16% for the first 15 years and 10.21% thereafter, compounded annually. Blended payments of principal and interest are made monthly. The loan is non-recourse to APCo and is secured by the Facility and the ownership interests therein.

Under the terms of the credit agreement, a debt reserve is required. In 2008, APCo issued an irrevocable letter of credit in an amount of $1.2 million to replace the debt service escrow deposit. At December 31, 2011, the debt reserve was fully funded using the irrevocable letter of credit.

In addition, APCo owns the LSR Subordinate Note.

v) APMI Residual Ownership Interest

APCo's interest in Long Sault is by way of subscribing to two notes from the original developers, which effectively entitles it to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the equity cash flows commencing in 2014. Subsequent to December 31, 2012, APCo reached an agreement with the affiliate of APMI to acquire residual partnership interest in the Long Sault Rapids hydroelectric facility as part of an agreement to resolve a number of the historic business relationships between APCo and APMI. (See "*Recent Developments – 2012: Business Associations with APMI and Senior Executives*").

(2) Côte Ste-Catherine Facility

The Côte Ste-Catherine Facility is a hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The Facility has a total installed capacity of 11.1 MW. The Facility is owned by the Mont-Laurier Partnership.

The land and water rights necessary for the operation of the Facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement with the Province of Québec. In 2009, the water rights lease was renewed for a term of 21 years commencing March 1, 2009. Although the Facility is located on a federal waterway, the Province of Quebec has asserted jurisdiction over the water rights to this Facility and has also asserted a claim against a predecessor by amalgamation to APFC for payment of revenues paid to the federal authority. See "*Legal Proceedings and Regulatory Actions – Legal Proceedings*".

(3) Mont Laurier Facility

The Mont Laurier Facility is a 2.7 MW hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The Facility is owned by the Mont-Laurier Partnership.

The Facility is constructed on lands owned by the Mont-Laurier Partnership. Water rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources (Québec) pursuant to a lease agreement dated March 23, 1988 and assigned to the Mont Laurier Partnership on October 31, 1994. The term of the lease expires on December 31, 2023.

(4) Côte Ste-Catherine and Mont Laurier, PPAs—General

Each of the Côte Ste-Catherine and Mont Laurier Facilities have PPAs with Hydro-Québec under which all power generated by the facilities is sold to Hydro-Québec. The standard Hydro-Québec PPA stipulates annual minimum energy production requirements in each contract year. Under most Hydro-Québec PPAs, if a facility produces less energy than the minimum, a penalty is payable to Hydro-Québec. The facility can opt to reduce any energy production shortfall over a two year period using energy produced in excess of the minimum requirement, after which, a penalty is payable on any outstanding amounts at the current year prices.

Power purchase rates under the Hydro-Québec agreements (other than for the Mont Laurier and Côte Ste-Catherine (Phase I) Facilities) increase in accordance with the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. The Mont Laurier Facility is subject to a fixed annual escalation of 1.8%. The Côte Ste-Catherine Facility (Phase I) power purchase rate increases at a fixed annual index of 1.1% for the first four years and 1.8% thereafter.

(5) Tinker Hydro Facility

The Tinker Facility is located 5 miles north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The Facility consists of five hydro units and a 1 MW diesel generator; the total nameplate capacity of the station equals 34.5 MW. Unit 5 of the Facility is currently operating as a fixed bladed runner. Historical gross generation from the station averages 120,000 MW-hrs per year. The Facility benefits from the flow regulation of the Squa Pan Facilities, both of which are also owned and operated by APCo.

i) Transmission facilities

As part of the generation assets in New Brunswick and Northern Maine, APCo owns and operates an electrical transmission system consisting of 14.7 km of 69 kV transmission line facilities. These facilities are used to interconnect the Tinker Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/import capacity between Maine and New Brunswick. The transmission facilities are currently included in the Open Access Transmission Tariff of the NBSO.

ii) PPA

The Facility supplies approximately 31,000 MW-hrs per year to the municipal utility of Perth-Andover under a PPA expiring in 2021. The remaining generation from the plant, approximately 89,000 MW-hrs per year, is sold to AES for resale to commercial and industrial customers in the northern Maine and New Brunswick markets, as well as energy and capacity to the Maine and New Brunswick electricity markets.

(6) Dickson Dam Facility

The Dickson Dam Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River. The Facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

i) PPA

The Dickson Dam PPA with TransAlta Utilities Corporation ended on January 16, 2012. Since January 17, 2012, the Facility is participating in the Alberta Power Pool selling electricity at the real time market price. APCo is exploring options to sell power to a third party and expects to put a fixed price contract in place for the output from the Facility in the second quarter of 2012.

ii) Use of Works Agreement

The Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available water flows for generating power until March 31, 2030. The Use of Works Agreement provides certain rights in favour of the Minister of Environment (Alberta) in connection with the Minister’s water management objectives.

(b) Power Generation: Renewable—Wind Power

(i) Production Method

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.

(ii) Principal Markets and Distribution Methods

The principal market for APCo's St. Leon Facility is Manitoba. The electricity generated by the wind turbines at the St. Leon Facility is transmitted via underground distribution lines to the facility's substation for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**"). The purchaser then distributes the electricity to its customers or to other endpoints via the grid.

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

The Manitoba government and Manitoba Hydro have independently undertaken studies to determine the potential of wind power generation in Manitoba. As a result of such studies, the Manitoba Government has advised it plans to have additional capacity of approximately 1,000 MW of wind power, to be constructed, using in part, independent power producers by 2014.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through Crown Investments Corporation. SaskPower anticipates requiring 1,700 MW of additional supply by 2020 and 3,700 MW by 2030 to accommodate load growth and the retirement of generation facilities. As part of this, SaskPower has a number of programs to encourage and solicit wind and other renewable power from independent producers.

(iii) Material Facilities

(1) St. Leon Facility

The St. Leon Facility is a 104 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The facility is owned by St. Leon LP.

On September 18, 2007, the St. Leon Facility achieved commercial operation pursuant to a turn-key construction contract dated November 12, 2004. In January 2010, APCo executed an Operation and Maintenance Service Agreement with Vestas-Canadian Wind Technology, Inc. ("**Vestas**") whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon Facility for approximately 20 years.

i) PPA

St. Leon LP and St. Leon GP have entered into a PPA with Manitoba Hydro dated as of October 28, 2004 under which all electricity produced at the St. Leon Facility is sold to Manitoba Hydro.

As of June 17, 2006, the facility achieved commercial operation status under the PPA with Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional 5 years. Under the terms of the PPA, security in an amount of $1.8 million is required and as at December 31, 2011, the security was fully funded using an irrevocable letter of credit.

St. Leon LP entered into a Wind Power Production Incentive ("**WPPI**") agreement with the Ministry of Natural Resources—Canada which entitles the St. Leon Facility to receive an incentive from the Federal Government of $10.00 per MW-hr to a maximum of $3.7 million annually for a period of ten years ending March 2016. APCo anticipates that the facility will earn WPPI of approximately $3.0 million annually based on the current estimated long term wind resource.

ii) Credit Facility

A banking syndicate provided the AirSource Senior Debt to St. Leon Trust to finance construction of the St. Leon Facility. The AirSource Senior Debt had an amount of $67.8 million outstanding as at August 2011 when it was repaid. There is currently no debt agreement with external third parties associated with this facility.

(c) Power Generation: Thermal—Energy From Waste

(i) Production Method

In North America and elsewhere, the combination of increasing population and stricter environmental regulations has imposed increasing limitations upon the development of new municipal landfills and on the expansion of existing landfills. Energy-from-waste facilities are considered a viable option to reduce the total tonnage of municipal waste being directed to landfills and to extend the useful life of existing landfills. The establishment of energy-from-waste facilities is now a licensed process in certain states of the United States and Canadian provinces.

The incineration process reduces the waste to an ash which is less than one third of the original volume of waste. The residual ash is then transported to a land fill. The heat recovered from municipal solid waste is used to make steam which can be used to provide thermal energy or can be used to drive turbines and generate electricity.

(1) Principal Markets and Distribution Methods

See "*Material Facilities*" immediately below.

(ii) Material Facilities

(1) EFW Facility

The EFW Facility is a 10 MW generating station located in Brampton, Ontario which produces electricity from incinerating non-recyclable materials, including municipal solid waste. The facility is designed to incinerate over 500 tonnes per day of municipal solid waste from five incinerators to produce an average of approximately 60,000 pounds per hour of steam which is the excess of the steam required for production of internally consumed electricity. It is owned by APEFW which forms part of the APCo ownership chain.

The principal customer of the EFW facility is the Region of Peel (the "**Region**"). The facility is currently permitted to accept domestic waste from the Region of Peel and non-hazardous commercial/industrial waste from the Regions of Peel, Halton, York, Durham and the City of Toronto. In addition the facility is permitted to accept international airport waste from Pearson and Hamilton International Airports. The facility is currently working to amend its permits to accept domestic waste from all of Ontario and expects to conclude this process in 2012.

The majority of the EFW steam is diverted to the BCI Facility. See "*Description of the business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Thermal: Cogeneration – Material Facilities – BCI Facility*". A portion of the EFW Facility steam is used by the EFW Facility to generate electricity in a steam turbine generator, the electricity from which is used to supply internal operations with any excess generation being sold to OEFC.

i) PPA

The EFW Facility is selling electricity at the Hourly Ontario Energy Price ("**HOEP**"). The HOEP is the hourly price that is charged to local distribution companies, other non-dispatchable loads and self-scheduling generators. APCo is currently negotiating with the OPA to enter into a new long term contract for the power output from the EFW Facility.

ii) Fuel Supply

Under a "tip or pay" waste supply agreement, the Region supplies the facility with a minimum of 127,900 tonnes per year of acceptable municipal solid waste. The EFW facility "tip or pay" waste supply agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility.

(d) Power Generation: Thermal–Cogeneration

(i) Production Method

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. Often natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

Where both electrical and thermal energy are generated separately, typically one third to one half of the fuel's energy content is converted into useful energy output such as steam or electricity. The remainder is wasted energy which escapes as unused heat. By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel's energy content. Depending on the degree of steam and/or useful heat utilization, 55% to 80% of the fuel's energy content is converted into useful energy output, which produces significant fuel savings over conventional arrangements.

Cogeneration compared to conventional processes also has environmental benefits as it results in burning less fuel and producing less carbon dioxide. Furthermore, in cogeneration facilities which use fuels such as natural gas or oil, sulphur dioxide and nitrous oxide emissions are greatly reduced compared to other technologies and fuels.

(ii) Principal Markets and Distribution Methods

The principal markets of APCo's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to Independent System Operator rules. In addition, electrical capacity and other ancillary services are sold either under the terms of a long term contract or according to the Independent System Operator rules. A summary of the contracts for the Cogeneration facilities is attached in Schedule B. In addition to grid sales of electricity and power, electricity and thermal energy is also sold to nearby third party purchasers for use in their production facilities.

(1) California

The electric transmission system and wholesale markets in California are primarily regulated by the California Energy Commission and FERC. The California Independent System Operator administers the wholesale electricity market place for the region.

(2) Connecticut

Connecticut Light and Power Company ("**CL&P**") is part of the North East Utilities System which is located in the New England Power Pool. The Independent System Operator New England ("**ISO-NE**") was established as a not-for-profit, private corporation on July 1, 1997 following its approval by FERC. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

Since May 1, 1999, ISO-NE has also administered the wholesale electricity marketplace for the region. Six electricity products are bought and sold by market participants on an internet-based market system.

(iii) Material Facilities

(1) Sanger Facility

The Sanger Facility is a 56MW natural gas-fired generating facility located in Sanger, California. The Facility is a combined cycle generating station comprised of a 44 MW General Electric LM6000 natural gas fired turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, commissioned in 1991. The Facility is owned by Algonquin Power Sanger LLC, a subsidiary of APFA.

i) PPA

Output of the Facility is governed by the terms and conditions of a firm capacity and energy PPA with Pacific Gas & Electric Company ("**PG&E**"). The agreement has a term of 30 years, expiring in 2022, and calls for delivery of 38 MW of firm capacity.

ii) Fuel Supply

Natural gas for the Facility is delivered under the terms of a gas supply agreement dated August 1, 2006 with Constellation NewEnergy for the purchase and sale of all natural gas required for the facility. The expected gas requirement for the subsequent month is bought at the market rates available on the gas nomination date, which is typically the 20th day of each month. Gas above or below the nomination requirement can be bought or sold at the applicable spot prices.

iii) Energy Lease

Pursuant to a lease, energy supply and common services agreement with Dyna Fibers Inc., a wholly-owned subsidiary of Sanger LLC, Dyna Fibers Inc. leases a portion of the facility site in order to carry on its hydro mulch business and purchases certain energy at a cost equal to a percentage of the fuel costs incurred by the Facility, to offset the incremental cost of fuel to supply such energy. The water consumption, exhaust heat and steam consumption by the hydro mulch operations are metered and recorded for FERC qualifying facility calculations that are submitted to PG&E on an annual basis.

iv) Credit Facility

There is an outstanding senior loan against the Facility in the amount of US $19.2 million as at December 31, 2011. The loan is a California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bond, due September 1, 2020. The senior loan bears interest at variable rates, reset monthly. Interest is payable monthly with no principal repayments. The effective interest rate in 2010 was 1.33%. The loan is secured solely by the Facility, the ownership interests therein and an irrevocable letter of credit in an amount of US $19.5 million.

(2) Windsor Locks Facility

The Windsor Locks Facility is a 56 MW natural gas-fired generating facility located in Windsor Locks, Connecticut. The Facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine and was commissioned in 1990. The Facility is owned by Windsor LLC.

Prior to April 2010, the Facility ran at capacity, providing the steam and power requirements of Ahlstrom pursuant to the ESA with the remainder of the electrical generation being sold to CL&P. With the expiry of the PPA with CL&P, APCo determined that the existing gas turbine is not appropriately sized to meet the electrical and steam requirements of Ahlstrom.

APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027, and supports the installation of a new 14 MW Solar Titan combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is being installed with commercial operation expected in

July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Facility of approximately U.S. $500,000/year.

In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO NE market when it is commercially profitable to do so. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("**ITC**") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

i) Energy Services Agreement and Ground Lease

The Facility supplies thermal steam energy and a portion of electrical generation to Ahlstrom, a leading paper and non woven materials manufacturer, pursuant to a ground lease and the ESA. Pursuant to the ESA, Ahlstrom leases the facility site to Windsor LLC and utilizes thermal steam energy and a portion of electrical generation of the Facility for use at its specialty fibers composites mill located adjacent to the Facility. APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Facility.

ii) PPA

The electrical output of the Facility not used to meet Ahlstrom's requirements is committed to the ISO-NE electricity market. Since April 2010, the Facility has bid its remaining available capacity of approximately 40 MW into the thirty minute forward operating reserve market. APCo's AES group manages the off-take sales from this Facility into the ISO-NE market.

iii) Fuel Supply

Natural gas for the facility continues to be delivered under a gas supply agreement with Yankee Gas Service Company ("**Yankee Gas**"). Gas is supplied by Yankee Gas at a percentage of its weighted average cost of gas for the month. The gas contract contains minimum annual consumption requirements with associated penalties for shortfalls. The Yankee Gas agreement was scheduled to terminate coincident with the PPA. APCo has agreed with Yankee Gas that the arrangements under the existing contract will be maintained until the new turbine is installed.

APCo and Yankee Gas continue to negotiate a new agreement that will allow the Facility to use Yankee Gas as a local distribution company which will enhance the Facility's purchase options for its natural gas requirements. It is expected that once the new turbine is installed the existing contract will be replaced by individual contracts for each of the new combustion turbine, the auxiliary boilers and the existing Frame 6 turbine. Yankee Gas is currently upgrading the gas service to accommodate the new combustion turbine.

(3) BCI Facility

The BCI Facility is a cogeneration facility located in Brampton, Ontario on the EFW Facility site. It was commissioned and became operational in June 2008. The project was established to meet the steam requirements of a nearby recycled paper board manufacturing mill that requires approximately 90,000 pounds of steam per hour in its manufacturing activities.

The Facility consists of a 150,000 pound per hour gas-fired boiler, a water treatment system, pumps to support the boiler, a twelve inch diameter pipeline to supply a nearby recycled paper board manufacturing mill with steam and a six inch diameter pipeline for condensate return. The majority of the steam supplied to the mill is produced by the EFW Facility with the gas-fired auxiliary boiler supporting peak steam demand and providing full standby capacity during normal downtime periods at the EFW Facility and where operations at the EFW Facility cannot provide sufficient volume of steam.

(4) Kirkland Facility

The Kirkland Facility is a 132MW combined cycle integrated fuels generation station located in Kirkland Lake, Ontario owned by Kirkland Lake Power Corp. ("**Kirkland**") which burns natural gas and wood waste to generate electricity using four gas turbines and two steam turbines. The Facility was developed in two phases: the first 102MW was commissioned in 1991, operating in baseload, and the remaining 30MW was added in 2004 as a dispatchable or peaking plant. Northland Power Inc. ("**Northland**") manages the operations. Electricity produced by the Facility is sold to OEFC pursuant to a 40 year contract, which expires in 2030. Natural gas used by the Facility is supplied under 20 year supply contracts. Price increases under such gas supply agreements are generally tied to price increases under the PPAs with OEFC. Wood waste consumed by the Facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 32.4% of the Class B non-voting shares issued by Kirkland. It is Kirkland's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Kirkland had a put option to sell the Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $10 million. Further to a shareholder meeting on November 12, 2009, the Kirkland shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the Facility is paid to Northland under the management agreement.

(5) Cochrane Facility

The Cochrane Facility is a 40MW combined cycle integrated fuels generating station located in the Town of Cochrane, Ontario. The Facility is owned by Cochrane Power Corporation ("**Cochrane**") which burns natural gas and wood waste to generate power using a gas turbine and a steam turbine. The Facility was commissioned in 1990 and is currently managed by Northland. Electricity produced by the Facility is sold to OEFC pursuant to a 25 year contract, which expires in 2014. The majority of the natural gas used by the Facility is supplied under a supply contract which expires in 2016. Price increases under such gas supply agreements are generally tied to price increases under the PPA with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 25 years.

APT owns 25% of the Class B non-voting shares issued by Cochrane. It is Cochrane's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Cochrane had a put option to sell the Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $3 million. Further to a shareholder meeting on November 12, 2009, the Cochrane shareholders decided not to exercise the put option as the present value of the expected future dividends from this investment were expected to exceed funds they would receive from the put option. As a result, subsequent to February 28, 2011, 75% of operating income of the facility is paid to Northland under the management agreement.

(e) Power Generation: Algonquin Energy Services

The primary business of AES is to market the output of the Tinker Facility and other APCo owned assets which would otherwise sell the energy they generate on a merchant basis. AES also works to develop strategies for selling the power output of other APCo facilities that are approaching the end of their PPAs and to engage, where possible, in actual selling of power for APCo facilities that would otherwise sell power on a merchant basis.

(i) Production Method

AES provides standard offer contracts and direct customer contracts for the supply of energy to commercial and industrial customers using a series of short-term energy supply agreements.

(ii) Principal Markets and Distribution Methods

AES provides energy to commercial and industrial customers in the northern Maine and New Brunswick markets. AES anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 100,000 MW-hrs of energy to its customers.

AES purchases the majority of its energy requirements from the Tinker Facility. Based on historical long term average levels of hydroelectric energy generation, the Tinker facility is anticipated to provide greater than 65% of the energy required by AES to service its customers and provides a natural hedge on supply costs of AES.

In addition to the energy generation provided by the Tinker Facility, AES purchases additional energy on the open market in order to services its customer demand. APCo manages the risk associated with this business through internally generated energy from the Tinker facility, as well as through the purchase of fixed volume/prices from the ISO-NE market. In addition, AES negotiates appropriate consumption volumes and pricing indexes with large retail and wholesale consumers in northern Maine to ensure risk associated with volatility of consumption by the consumer is mitigated.

(iii) Material Facilities

AES operates using a series of energy supply agreements. These include energy sales to a town in New Brunswick, Standard Offer Service contracts with two local electric utilities in northern Maine, and a series of direct energy contracts with commercial buyers also in northern Maine. AES has energy purchase obligations with the ISO-NE as required to supplement self-generated energy.

AES entered into a three year contract with MPS starting March 1, 2011 to provide Standard Offer Service to multiple commercial and industrial customers in Northern Maine. The anticipated annual customer load associated with the standard offer service is approximately 135,000 MW-hrs.

(f) Power Generation: Development

(i) Target Markets / Development Strategy

The Development division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. It utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The Development division believes that the prevailing economic climate has also created opportunities for APCo to acquire third party development projects on terms that require the experience and financial resources that APCo has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

(ii) Principal Market Environment

APCo believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the U.S., continue to increase targets for renewable and other clean power generation projects. As an example, the Ontario government passed the GEA. Accordingly the OPA has issued standard pricing for electricity from renewable sources under a FIT program. Included within this legislation is the requirement for OPA to purchase power generated from green energy projects, and an obligation for all utilities to grant priority grid access to such projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.

Other jurisdictions have passed or are considering similar legislation to provide incentives for development of new renewable power generation from independent producers. The combination of increased renewable production targets and appropriate fixed pricing will present investment opportunities for APCo to consider in the future.

APCo continues to actively pursue development projects which provide the opportunity to exhibit accretive growth. APCo anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being extensively supported by Canadian provincial governments and several U.S. states.

(iii) Current Development Projects

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. The projects are as follows:

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind [1]	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$230.0	2014	25	247.0
Morse Wind [3, 4]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$70.0	2013	20	86.0
Val Eo [1]	Quebec	24	$70.0	2015	20	66.0
St. Leon II [1]	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar [1, 2]	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

Notes:

1 PPA signed

2 FIT contract awarded

3 Two 10 MW PPAs; one 5 MW PPA

4 Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

(1) Chaplin Wind

Subsequent to December 31, 2011, APCo entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan.

The project has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $355 million and consist of approximately 77 multi-megawatt wind turbines. The project is expected to generate first full year EBITDA of $37.5 million. The 25 year PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of a favourable interconnection location by interconnecting with SaskPower's new P1S 230 kV transmission line from Swift Current to Moose Jaw and will be compliant with SaskPower's latest interconnection requirements.

(2) Amherst Island Wind

The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the OPA as part of the second round of the OPA's FIT program.

The FIT contract originally stated that the OPA had the option to terminate the FIT contract prior to the date that the OPA had issued a Notice to Proceed ("**NTP**") and APCo had paid the incremental security required by the NTP. On August 2, 2011, the Ontario Ministry of Energy directed the OPA to offer FIT contract holders the opportunity to have the OPA's termination rights under the FIT contract waived. APCo exercised this option on August 9, 2011. As required by the waiver, APCo submitted a domestic content plan on October 14, 2011 and provided a statutory declaration regarding equipment supply commitments by November 30, 2011.

The project is currently contemplated to use efficient Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GWhr of electrical energy annually, depending upon the final turbine selection for the project. Total capital costs for the facility are currently estimated to be $230 million. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. Environmental studies and engineering are underway. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 to 18 months.

(3) Morse Wind Project

The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

APCo executed an asset purchase agreement with a local developer ("**Kineticor**") to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APCo independently. All of the individual projects comprising the Morse Wind Project were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011. Upon SaskPower's approval and execution of the Kineticor PPAs, Kineticor will then assign the PPAs to APCo. All three of the projects are expected to be completed contemporaneously in early 2014.

The total annual energy production for the Morse Wind Project is estimated to be 93,000 MWhr. The capital cost to construct the Morse Wind Project is currently estimated to be $65-$70 million, inclusive of acquisition costs. The first year PPA rate is set at $101.98 per MWhr for the first full year of operations, which APCo expects to occur in 2014, with an annual escalation provision of 2% over the expected 20 year term.

(4) Quebec Community Wind Projects

In 2010, APCo worked with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded power purchase contracts that stipulate the use of ENERCON wind turbines.

i) Saint-Damase

The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APCo. The first 24 MW phase of the project is expected to be comprised of eight to twelve generators (depending on the cost and generating capacity of the selected wind turbine model), producing approximately 86,000 MWhr annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

The interest of APUC in the project will not be less than 50%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing. Meetings were conducted July 2011 and March 2012 with participating landowners in addition to open houses to obtain additional community feedback. All major environmental authorizations are targeted for completion by the end of 2012.

ii) Val-Éo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight generators, producing approximately 66,000 MWhr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interest of APUC in the project is subject to final negotiations with the cooperative but, in any event, will not be less 25%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing with all major authorizations targeted for completion by the end of 2012.

(5) St. Leon II

In July 2011, APCo executed a 25-year PPA with Manitoba Hydro in respect of St. Leon II (a 16.5 MW expansion of APUC’s existing St. Leon wind energy project located in the Province of Manitoba). Construction of this project commenced on August 30, 2011 using 10 Vestas V82 turbines. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The project is expected to achieve commercial operation in the second quarter of 2012. The total capital cost of the project is expected to be $29.5 million.

(6) Cornwall Solar

APCo entered into a share purchase agreement with EffiSolar to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the FIT pipeline have submitted FIT applications for an additional 100MWac.

The project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MWhr, resulting in expected initial annual revenues of approximately $6.2 million. The Project contemplates the use of a ground-mounted PV array system, with expected annual generation of approximately 13,400 MWh, enough to provide electricity to approximately 1,000 homes.

Following the completion of all regulatory submissions and approvals, construction of the project is expected to begin in the second half of 2012, with a Commercial Operation Date estimated in early 2013. The project is being developed on two parcels of leased land totalling approximately 138 acres.

Total capital cost of the project is targeted at approximately $45 million, which amount includes the consideration to be paid for the acquisition of the project. Funding for the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

(7) Other

APCo has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. APCo believes this project is an excellent fit for the Minister of Energy and Infrastructure's (the "**Ministry**") Directive to procure electricity from combined heat and power projects. The Ministry is currently taking registrations from interested parties that wish to participate in such a program.

(iv) Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the U.S.

(g) Utilities: Water and Wastewater

(i) Method of Providing Services and Distribution Methods

A utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation.

The raw water for human consumption is sourced from the ground and extracted through wells or from surface waters such as lakes or rivers. The water is treated to potable water standards that are specified in Federal and State regulations and which are typically administered and enforced by a State or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility.

The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fee, reconnects, etc.

In respect of sewer or wastewater services, the sewage or wastewater produced by the customer flows through a buried service lateral line from the house or commercial space to the street which line is owned and maintained by the customer. This line feeds into collection pipes or lines (collection mains) located under or adjacent to the street which pipes are owned and maintained by the private utility. These pipes generally slope at a grade of approximately 1% as gravity is generally relied on to facilitate flows. On long line runs where maintaining slopes would result in excessive depths below grade or to traverse variable terrain, the line may terminate at a lift station where wastewater is collected and then pumped up to feed into another line located closer to the surface level where the wastewater can continue to flow by gravity.

The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks digested and or dewatered and the resulting solids sent to landfill or to land application as a soil amendment. The treated water, referred to as "effluent", is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface waters. The standards to which this wastewater is treated are specified in each treatment facilities operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on Federal and State regulations which are administered and continuing compliance therewith enforced by the State agency to which Federal enforcement powers are delegated.

(ii) Principal Markets

The principal markets of Liberty Utilities (South) are located in Arizona, Texas and Missouri. The Liberty Utilities (South) region's facilities are generally subject to regulation by the public utility commissions of the States in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The utilities use a historic test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Utilities (South) monitors the rates of return on each of its utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for the Wastewater Treatment and Water Distribution business unit is attached in Schedule C.

(1) Arizona

The Arizona Corporate Commission ("**ACC**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The Arizona Department of Environmental Quality ("**ADEQ**") and the Arizona Department of Water Resources in conjunction with various County agencies (county health units) have primary jurisdiction respecting environmental regulation and compliance.

(2) Texas

The Texas Commission on Environmental Quality (the "**TCEQ**") is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. The TCEQ also has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal *Clean Water Act* and the *Safe Drinking Water Act*, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(iii) Material Facilities

(1) Gold Canyon Facility

The Gold Canyon Facility is a wastewater treatment facility established in 1984 to serve a number of residential developments and in an unincorporated area of Pinal County referred to as Gold Canyon, approximately 25 miles east of downtown Phoenix, Arizona. The Facility currently serves over 7,300 residential and commercial customers. The Gold Canyon Facility is owned by a wholly-owned subsidiary in the Liberty Utilities (South) region.

The treatment plant utilizes a biological nutrient removal process combined with a sequencing batch reactor with a treatment capacity of 1.9 million gallons per day ("**gpd**").

The Facility is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on two neighbouring golf courses. Excess reclaimed water is recharged (put back into the ground to replenish underground water) via three recharge ponds. The treatment facility operates under ADEQ – Aquifer Protection Permits and Reuse Permits.

(2) Litchfield Park Facility

The Litchfield Park Facility is a water distribution and wastewater treatment facility located in the city of Goodyear, 15 miles west of Phoenix, Arizona whose service area includes sections of the cities of Goodyear and Avondale. The Litchfield Park Facility is owned by a wholly-owned subsidiary of the Liberty Utilities (South) region.

The Facility presently serves approximately 16,500 water and 18,500 wastewater customers. The wastewater facility has permitted capacity of 4.1 million gpd. The Facility's water infrastructure includes a total of twelve active wells, a 6.3 million gallon reservoir and a 4.0 million gallon reservoir which provides water to the current customer base through a single pressure zone. In 2007, in response to high growth in connections, the Facility began preparing design plans for expansion of its wastewater treatment facility. However, while permitting such expansion is currently underway, slowed growth has now postponed such construction plans and expansion of capacity is now anticipated to begin in 2012 or 2013, depending on local demand growth occurring. The Facility now operates at approximately 85% of design capacity. The Facility supplies Class "A+" effluent to a number of local golf courses in the area.

i) Rate Cases

On October 5, 2010, Liberty Utilities (South) received a recommended order ("**ROO**") for the Facility proposing an annualized revenue increase of U.S. $8.1 million. At the ACC open meeting held on December 10, 2010 to consider the ROO, the approved revenue increase was reduced to U.S. $7.1 million, with new rates effective December 1, 2010. As part of the Litchfield ROO, the rate increase will be phased in with 50% of the increase being applied in the first 6 months, increasing to 75% for 6 months thereafter, and 100% of the rate increase being realized from month 12 forward. Litchfield is entitled to recover the foregone revenue from the phase in of rates including carrying charges at 7.72%, over an approximate 18 month period, until the Company is made whole for the foregone revenue. The recovery of the foregone revenue became effective December 1, 2011 under Decision 72682.

ii) Credit Facility

The Facility currently has outstanding indebtedness to the City of Goodyear in the amount of U.S. $11.0 million in respect of which the City of Goodyear has acted as a conduit issuer of a like amount of Industrial Development Authority bonds. The bonds consist of two series, both fully amortizing over a 30 year term. The first series was issued in 1999, has a principal amount as of December 31, 2011 of U.S. $3.6 million bearing interest at rates between 5.85% and 5.95%. The second series was issued in 2001 with a principal amount as of December 31, 2011 of U.S. $7.1 million and bearing interest at rates between 6.3% and 6.75%. As partial security for these bonds, the Facility is required to hold funds in a restricted, interest bearing, investment account. The balance of this account at December 31, 2011 was U.S. $1.1 million.

(3) Rio Rico Facility

The Rio Rico Facility is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona. The Facility serves approximately 6,700 water and 2,200 wastewater connections in the community of Rio Rico, Arizona. The Facility is owned by a wholly-owned subsidiary of Liberty Utilities (South).

The Facility has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the ACC.

(4) Rate Cases—General

In 2010 and 2011, Liberty Utilities (South) completed the regulatory process with rate cases relating to a number of its facilities. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Utilities (South) monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments.

The following table sets out some particulars with respect to the status of Liberty Water's rate cases as at March 30, 2012:

Completed Rate Cases Facility	Date of Rate Increases	Test year	Annual U.S. $ Revenue Increase Granted
Arizona			
Black Mountain	October 2010	June 30, 2008	$0.7 million
Litchfield	December 2010	September 30, 2008	$7.1 million
Rio Rico	February 2011	December 31, 2008	$0.9 million
Bella Vista, Northern and Southern Sunrise	April 2011	March 31, 2009	$0.7 million
Texas			
Texas Utilities (Silverleaf – 4 utilities)	October 2009	December 31, 2008	$1.2 million
Tall Timbers	July 2009	December 31, 2008	$0.2 million
Woodmark	January 2010	December 31, 2008	$0.1 million

(h) Liberty Utilities: Electrical Distribution

(i) Method of Providing Services and Distribution Methods

Electricity distribution is the final stage in the delivery of electricity to end users. A distribution system's network carries electricity from the transmission system and delivers it to consumers or other end users. Typically, the network would include medium-voltage (less than 50 kV) power lines, electrical substations and pole-mounted transformers, low-voltage (less than 1 kV) distribution wiring and sometimes electricity meters.

An electric distribution utility sources and distributes electricity it to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities which can use various fuels such as water (hydro), natural gas, coal, biomass, wind, nuclear and solar. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customer where the voltage is again lowered through a transformer for use by the customer.

The fees or rates charged for electricity are comprised of a fixed charge component plus a variable fee based on the cost for generation, transmission and distribution of the electricity. Additional fees are typically chargeable for other services such as establishing a connection, late fee, reconnections, etc.

Liberty Utilities (West)'s facility is subject to state regulation and rates charged by these facilities may be reviewed and altered by the State regulatory authorities from time to time.

(ii) Principal Markets

The principal market of Liberty Utilities (West) is currently in the State of California. The utility operates under a cost-of-service regulation. The utility uses a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on facilities, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which the utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Liberty Utilities (West) monitors the rates of return on its utility investment to determine the appropriate time to file a rate case in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for Liberty Utilities (West)'s California Utility is attached in Schedule D.

(1) <u>California</u>

The CPUC regulates electrical utilities in California. The CPUC has jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These regulatory bodies have the authority to establish the allowed rate of return on approved rate base and also determine which investments are approved for inclusion in the rate base which in both cases can affect the profitability of the division.

The California regulatory regime requires regular general rate case filings. This obligates any regulated utility operating in California to file a rate case every 3 years and allows for the use of a prospective test year in the establishment of rates for the utility. The CPUC also allows the use of annual adjuster mechanisms to account for inflation to labour and other expenses over the three year period of the rate case filing. In addition, a utility's rates include thresholds for capital expenditures, which once reached, can trigger adjustment mechanisms in between rate cases.

The Energy Cost Adjustment Clause ("**ECAC**") allowed in California mitigates the impact of changes in fuel prices and stabilizes earnings by allowing for the recovery of fuel and purchased power costs by updating rates charged on an annual basis. The Post Test Year Adjustment Mechanism ("**PTAM"**) allows Calpeco to update its rates annually by a cost inflation index. In addition, rates are allowed to be updated to recover the return on investment and associated depreciation of major capital projects.

(iii) Material Facility

(1) <u>California Utility</u>

The California Utility provides electric service to the Lake Tahoe basin and surrounding areas. The service territory, centered around a popular tourist destination, has a primarily residential and small commercial customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in Northeastern California. The utility plant is comprised of approximately 94 miles of high voltage distribution lines, 13 substations, and 39 distribution circuits (14.4 kV) serving just over 47,000 customers in the seven County service territories. The customer base is heavily-weighted towards El Dorado and Placer Counties, which counties comprise approximately 89% of total revenues.

Calpeco is owned by CPUV, a 50.001% subsidiary of Liberty Utilities (West).

On April 29, 2011, pursuant to the Strategic Agreement, Emera and APUC agreed to the general terms by which Emera would sell its 49.999% indirect ownership in the California Utility to Liberty Utilities (West), with closing of such transaction subject to regulatory approval. As part of this transaction, Emera was issued 8.211 subscription receipts pursuant to the Subscription Agreement (Calpeco) and such subscription receipts will be converted into Common Shares in two tranches: 4,790,000 subscription receipts will convert into Common Shares following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in mid 2012) and the remaining 3,421,000 subscription receipts will convert into Common Shares following completion of the California Utility's first rate case, expected to be completed in early 2013.

i) Customer Base

Calpeco's customer base is primarily residential with exposure to large commercial accounts limited to under 20% of gross revenues. The existing commercial customers primarily consist of ski resorts, hotels, hospitals, schools and grocery stores with no single customer accounting for more than 3.6% of annual sales volume.

ii) Rate Case

Calpeco's most recent rate case was settled in 2009. On February 17, 2012, the California Utility filed a general rate case with the CPUC seeking, among other things, an increase of 10.0%, or $7.5 million in general rates, comprised of a $3.3 million increase in vegetation management costs, $13.0 million increase in distribution rates offset by reductions in commodity costs of $8.8 million. The rate case is for the prospective years of 2013-2015. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

iii) Kings Beach Generation

Calpeco has a local-area emergency backup generation facility at Kings Beach in Placer County, California. The facility consists of six new Caterpillar 3516 Engine diesel generation units with a total nameplate capacity of 12 MW. The units were installed in November 2008 at a cost of U.S. $16.5 million and have an estimated useful life of 30 years. The repowered facility meets all California environmental standards. Any non-preventative maintenance expenditures that may occur during the first five years of operation will be fully covered by the Kings Beach warranty.

In the event of a system outage, the Kings Beach Facility is able to provide back-up generation support to Calpeco's service territory until baseload power is restored. The facility includes quick-start technology which facilitates this support function. The new units are designed to be online and operating within 60 seconds of being activated. The facility has historically run an average of 200 hours per year.

iv) Energy Cost Adjustment Clause

ECAC is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. The mechanism consists of a base rate and amortization rate set at the time of the general rate case. The actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

v) Post Test Year Adjustment Mechanism

In years where Calpeco does not file a general rate case, its rates are updated on January 1st to reflect inflationary increases to its administrative, operations, and maintenance costs. The inflationary adjustment is set by the use of an index, less a presumed efficiency offset.

Calpeco may also file for an annual increase in rates to recover its investment costs in material capital projects. This increase is subject to a materiality threshold.

vi) PPA

Calpeco has entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at rates NV Energy's "system average cost". The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply Calpeco with sufficient renewable power to satisfy the current 20% California Renewables Portfolio Standard requirement for the five-year term of the PPA.

NV Energy's deliveries under the PPA are structured in a manner which satisfies the CPUC resource adequacy ("RA") requirements, and designed to enable Calpeco to comply with the associated RA reporting requirements.

vii) Credit Facility

Calpeco entered into a long term debt private placement in an amount of U.S. $70.0 million on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate, interest only, and split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes.

3.3 Revenues for 2011 and 2010

As at March 30, 2012, APUC owned, directly or indirectly, debt, equity and royalty and other interests in 47 renewable generation facilities and 12 thermal generation facilities including those identified in "Other Interests in Energy Related Developments", one electrical distribution facility and 21 water distribution and wastewater facilities. For the year ended December 31, 2011, APUC derived approximately 49.8% of its revenues from its interests in power generation facilities (74.4% in 2010), 5.9% of its revenues from waste disposal fees (4.9% in 2010), 28.0% of its revenues from electrical distribution and 16.3% of its revenues from its interests in water distribution and wastewater facilities (20.7% in 2010).

3.4 Specialized Skill and Knowledge

The senior executives of APUC have extensive contacts in the independent power industry in Canada and the United States. APCo, as well, has extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of APCo requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to APCo in-house.

The energy from wind aspect of the business of APCo requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to APCo in-house. On a more general level, the production of energy from all facilities of APCo requires specialized skill and knowledge, and APCo has employed various personnel who have such skill and knowledge.

AES requires specialized knowledge of the ISO-NE and the energy markets in Northern Maine. APCo has contracted the services of four personnel who previously performed these services for the vendor of the contracts acquired by AES.

The electrical distribution service business of Liberty Utilities (West) requires specialized knowledge of electrical utility distribution systems and its various components. Liberty Utilities (West) has contracted the services of 41 employees that previously operated and maintained the California Assets electrical distribution network. In addition Liberty Utilities (West) has also recruited an additional 35 qualified individuals to work in the service territory in various capacities, including Lineman, Customer Service and Financial. In late 2011, Liberty Utilities (West) hired a new regional president with over 30 years of electric utility experience.

In anticipation of the acquisitions of Granite State, Energy North and the Midwest Gas Utilities, in 2012, an experienced utility team has been recruited to support procurement of both natural gas and electricity by the utilities owned by Liberty Utilities. As with the acquisition of the California Assets, Liberty Utilities intends to contract the services of the existing operating personnel necessary to run the these new organizations as part of the completion of these acquisitions.

In addition, Liberty Utilities is adding additional utility trained personnel at its corporate offices to support the expanded portfolio of utility assets.

3.5 Competitive Conditions

APUC competes for projects and acquisitions with individuals, corporations and institutions (both Canadian and foreign) which are seeking or may seek investments similar to those desired by APUC. Availability of investment funds and an increase in interest in these investments may increase competition for them, thereby increasing purchase prices or development costs. Many of these investors have greater financial resources than those of APUC or operate according to more flexible conditions.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric power is not subject to commodity fuel price volatility or risk. In addition, the generation of hydroelectric power does not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind and water. Taking into account capital costs, wind power is generally more expensive than traditional forms of generated power. Fossil fuels are harmful to the environment, and waste burning power generation requires producers to abide by stringent and costly environmental regulations.

With deregulation and opening of competition in the electricity marketplace, there should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The US Department of Energy ("**DEP**") has suggested that in a competitive marketplace, utilities and energy marketers will utilize Green Power pricing to strengthen their image with their customers and build customer loyalty. Further, the DEP has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The DEP believes that as deregulation and open competition evolve, the Green Power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation.

Though programs and policies are evolving at all government levels, the trading of greenhouse gas credits created by renewable energy projects is seen as part of the eventual solution.

APUC believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects.

APUC is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources. It has experience and knowledge in the area. APUC will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. APUC anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being supported by virtually every Canadian Province and a significant number of U.S. States.

Liberty Utilities is the holding company for APUC's utilities businesses. The primary focus of Liberty Utilities is the acquisition of regulated utilities in the water, wastewater, electric transmission and distribution and natural gas distribution businesses. These businesses have geographic monopolies in their service territories and are therefore insulated from competition. Liberty Utilities has developed in-house significant regulatory expertise in order to effectively deal with the state regulators in the various jurisdictions in which it operates.

3.6 Environmental Protection

The APUC Businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, policies and legislation. Failure to operate the APUC Businesses in strict compliance with these regulatory standards may expose the APUC Businesses to claims, clean-up costs and loss of operating licences and permits.

APUC has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters.

Environmental protection requirements did not have a significant financial or operational effect on APUC's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2011. However it is expected that certain regimes will impact APUC, in terms of increased expenditures, and that these will not affect the competitive position of APUC. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets are expected to increase the earnings and benefit the competitive position of APUC.

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies. APUC has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore APUC has not recorded any contingent liabilities on its financial statements.

To manage these risks responsibly, APUC has ensured the Environmental and Compliance departments have been established within the different subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating Facilities are in compliance with environmental regulations and preparing regulatory submissions as required. In the aggregate, the departments comprise 12 full time equivalent positions and have an annual budget of approximately $1.6 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

APUC and its subsidiaries have procedures to prevent and minimize any impact of possible oil spills and soil contamination that meet generally accepted industry practices. APCo's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. Each of APUC's businesses have 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

3.7 Employees

APUC has 15 employees involved in the management of the corporation. APCo currently has 77 employees who are involved in the operation of the renewable energy facilities, 16 employees who provide technical, environmental and safety services to APCo, an additional 43 employees through its subsidiaries who are involved in the operations of the thermal Facilities, 29 employees who are involved in management and 5 employees involved in energy marketing. Labour relations have been stable to date and there has not been any disruption in operations as a result of labour disputes with employees. With the exception of 48 employees at the EFW Facility and 6 employees at the Tinker Facility, the employees of APCo entities are non-unionized.

Liberty Utilities, which provides managerial expertise to Liberty Utilities (South) and Liberty Utilities (West) currently has 28 employees. In addition, Liberty Utilities (South) currently has 136 employees. Liberty Utilities (West) currently employs approximately 77 employees. With the exception of 49 employees at the California Utility, the employees of Liberty Utilities employees are non-unionized

3.8 Foreign Operations

At the current exchange rate, approximately 55% of expected EBITDA in 2012 and 65% of cash flow from operations is generated in U.S. dollars. APUC has interests in hydroelectric, thermal, electric distribution, water distribution and wastewater treatment facilities located in the United States.

Currency fluctuations may affect the cash flow that APUC will realize from its operations, as certain APUC Businesses sell electricity in the United States and receive proceeds from such sales in US dollars. Such APUC Businesses also incur costs in US dollars.

3.9 Cycles and Seasonality

Based on the type of PPAs in place at all of the facilities in which APUC has an interest, the revenue generated by the facilities is proportional to the amount of electrical energy generated.

Power Generation—Hydrology

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher.

The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Due to the geographic diversity of the facilities, variability of total revenues will be minimized.

Power Generation—Wind

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of any wind farm. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

Power Generation—AES

For AES, demand for energy is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served by AES is located in a "winter peaking" region.

Liberty Utilities — Water distribution

Demand for water, in the Liberty Utilities (South) region, is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall the demand for water may decrease adversely affecting revenues.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Liberty Utilities — Electricity distribution

For Liberty Utilities, demand for and consumption of electrical energy is primarily affected by weather conditions and to a smaller degree conservation initiatives. Above normal snowfall, with lower temperatures in the Lake Tahoe area brings more ski resort tourists with an increased and consumption of demand for electricity by our customers. Liberty Utilities provides information and programs to its customers to encourage the conservation of energy. In turn, demand for and consumption of electrical energy may be reduced in the case of a mild winter (light snowfall & warmer winter) which could have adverse impacts to revenues. Liberty Utilities provides information and programs to its customers to encourage the conservation of energy.

3.10 Customers

The APUC Businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2011, APUC Businesses' revenues were derived as follows: Hydro-Québec—approximately 8.4%; Manitoba Hydro—approximately 8.1%; PG&E – approximately 5.3%; electricity sales facility – approximately 28.0%; water distribution and wastewater treatment facilities – approximately 16.3%; waste disposal fees – approximately 5.9% and others—approximately 26.9%.

3.11 Economic Dependence

The largest customer on a percentage basis is Hydro-Québec which totalled 8.4% of gross revenues in the year ended December 31, 2011. This customer maintains an A+ S&P rating and receivables are invoiced monthly and generally collected within 20 days.

Similarly, the second largest customer on a percentage basis is Manitoba Hydro which totalled 8.1% of gross revenues in the year ended December 31, 2011. This customer maintains an AA S&P rating and receivables are invoiced monthly and generally collected within 30 days.

Otherwise, APUC does not believe it is substantially dependant on any single contractual agreement or set of related agreements either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or licence or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

3.12 Social or Environmental Policies

APUC has safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into APUC's Safety Mission Statement and Employee manual.

APUC has an Environmental, Health and Safety Group that reports independently to the President of the appropriate region. This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

4. RISK FACTORS

The following are certain risk factors relating to the APUC Businesses. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this AIF and the documents incorporated by reference herein.

4.1 Treasury Risk Management

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that each of APCo, Liberty Utilities (South) and Liberty Utilities (West) maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

(a) Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC Businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 55% of EBITDA and 65% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately $5.4 million ($0.05 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC’s policy is not to utilize derivative financial instruments for trading or speculative purposes.

(i) **Liberty Utilities**

Liberty Utilities has operations in the U.S., incurs the majority of its operating costs in U.S. currency and generates all of its revenue from utility services in U.S. dollars. Liberty Utilities uses U.S. dollar long term debt as part of its capital structure. As such, Liberty Utilities has minimal foreign currency risk arising from U.S./Canadian currency fluctuations, with the exception of corporate head office charge backs based in Canadian dollars.

(b) Market price risk

APCo

The majority of APCo's electricity generating facilities sell their output pursuant to long term PPAs. However, certain of APCo's hydroelectric facilities sell energy at current spot market rates. In this regard, each $10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of $1.0 million on an annualized basis.

Liberty Utilities (South) and Liberty Utilities (West)

There is no exposure to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

(c) Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables, net receivable and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APCo

APCo does not believe this risk to be significant as approximately 82% of Renewable Energy division's revenue, approximately 48% of APCo Thermal Energy division's revenue, and over 68% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	23,200	26%
Manitoba Hydro	AA	22,400	25%
Ontario Electricity Financial Corporation	A+	11,000	12%
MPS**	BBB+	6,600	7%
TransAlta Corp – Dickson Dam	BBB	4,000	5%
Public Service Company of New Hampshire	BBB	3,200	4%
National Grid	A-	3,000	3%
Total		**$ 73,400**	**82%**
Thermal Energy Division			
Regional Municipality of Peel	AAA	16,400	25%
Pacific Gas and Electric Company	BBB+	14,600	23%
Total		**$ 31,000**	**48%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2012.

** MPS is a subsidiary of Emera. Emera is rated BBB+.

Liberty Utilities (South)

Liberty Utilities (South) does not believe this risk to be significant as approximately 75% of revenue are generated from the residential customer base and exposure to large commercial accounts is limited to less than 20% of gross revenues. The residential customer base provides a source of stable cashflows thereby further reducing credit/counterparty risk. Credit risk related to Liberty Utilities (South) accounts receivable balances of U.S. $5.1 million at December 31, 2011 is spread over approximately 76,000 customers, resulting in an average outstanding balance of approximately $70.00 per customer. In addition, no single customer accounts for more than 3.5% of annual sales volume.

Liberty Utilities (West)

Liberty Utilities (West) does not believe this risk to be significant as over 50% of revenue is generated from the residential customer base and exposure to large commercial accounts is limited to less than 20% of gross revenues. The residential customer base provides a source of stable cashflows thereby further reducing credit/counterparty risk. The existing commercial customer base primarily consist of ski resorts, hotels, hospitals, schools and grocery stores, which tend to exhibit characteristics similar to residential accounts (predictable usage patterns, low attrition, etc.). In addition, no single customer accounts for more than 3.6% of annual sales volume.

Credit risk is monitored on an ongoing basis with processes in place to check and evaluate this risk including background credit checks and security deposits from new customers.

(d) Interest rate risk

APCo

APCo has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The APCo Facility has no amounts outstanding as at December 31, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- APCo’s project debt at the St. Leon facility had a balance of $67.8 million as at June 30, 2011. The outstanding balance was repaid during the quarter ended September 30, 2011 using proceeds from the Senior Unsecured Debenture offering. Accordingly there is no further interest rate risk associated with this debt facility.
- APCo’s project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2011. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.

Liberty Utilities

As at December 31, 2011, Liberty Utilities has minimal exposure to interest rate risk.

Liberty Utilities (South) has existing project debt at the Litchfield and Bella Vista Facilities which are subject to a fixed rate of interest and thus is not subject to interest rate risk. Liberty Utilities (South) has fixed rate senior unsecured private placement borrowings of U.S. $50 million which is not subject to interest rate risk.

Liberty Utilities (West) has fixed rate senior unsecured private placement borrowings of U.S. $70 million which is not subject to interest rate risk.

Liberty Utilities has a senior debt facility that is subject to a variable interest rate. The facility and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Liberty Facility has no amounts outstanding as at March 30, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

(e) Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due.

APCo

APCo's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

During 2011, APCo concluded negotiations with its bank syndicate on the renewal of the APCo Facility. APCo also reduced the total of the APCo Facility to $120 million following the completion of the Senior Unsecured Debenture offering of APCo in July 2011.

As at December 31, 2011, no amounts had been drawn on the APCo Facility. In addition to amounts actually drawn, there were $39.6 million in letters of credit outstanding as at December 31, 2011, resulting in APCo having $80.4 million of committed and available bank facilities.

The cash flow generated from several of APCo's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APCo losing its investment in such operating facility. APCo actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Liberty Utilities

On January 19, 2012, Liberty Utilities concluded negotiations with its bank syndicate on entering into the Liberty Facility, a senior unsecured revolving credit facility. The Liberty Facility provides Liberty Utilities with sufficient liquidity to manage the short term working capital needs of its operations or allow investments in property, plant and equipment.

As the long term borrowings at Liberty Utilities (South) do not mature until 2020 and beyond and the long term borrowings at Liberty Utilities (West) do not mature until 2020 and 2025, there is no immediate liquidity risk associated with the long term debt.

Senior unsecured notes and project specific debt for Liberty Utilities (South) totals approximately U.S. $64 million. In the event that there is a breach of covenants or obligations with regard to any of the project specific debt which was not later remedied, the project level debt could go into default which could result in the lender realizing on its security and the company losing its investment in the respective operating facility.

Liberty Utilities actively manages both the cash availability in its regions and funds available under the Liberty Facility to ensure its operations are adequately funded and minimize the risk of this possibility.

(f) Commodity price risk

APCo

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk.

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million on an annual basis.
- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $1.4 million on an annual basis.
- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 130,000 MW-hrs in fiscal 2012. While the Tinker facility is expected to provide the majority of the energy required to service these customers, AES anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that AES was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $1.3 million on an annualized basis.
- This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 70,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. $50 per MW-hr. The mark-to-market value of these forward energy purchase contracts at December 31, 2011 was a net liability of U.S. $1.2 million.

Liberty Utilities (South)

Liberty Utilities' water distribution and wastewater collection and treatment utility systems are not subject to any material commodity price risk.

Liberty Utilities (West)

Liberty Utilities (West) provides electric services to the Lake Tahoe basin and surrounding areas at rates approved by the CPUC. Liberty Utilities (West) purchases the energy requirements for its customers from NV Energy at rates reflecting its system average costs. In the event that these rates change, each $10.00 change per MW-hr would result in a change in expense of approximately U.S. $6.5 million on an annualized basis.

The rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the ECAC mechanism, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance, including carrying charges, does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to the California Utility's approved rates (including carrying charges associated therewith), substantially eliminating the commodity risk associated with the purchase of power.

(g) Risk of Default under Senior Credit Facility

APCo

As security for repayment of the APCo Facility, APCo has, among other things, pledged the shares and other equity interests of certain of its subsidiaries. In addition to any amounts outstanding under the APCo Facility as described above, APCo has posted certain letters of credit totaling $39.6 million as security for obligations of the APCo businesses. The terms of the APCo Facility require APCo to pay a standby charge calculated as one quarter of the current stamping fee on the unused portion of the Senior Credit Facility and maintain certain financial covenants.

If the APCo Facility goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their security.

Liberty Utilities

The Liberty Facility is unsecured. In addition to any amounts outstanding under the Liberty Facility as described above, Liberty Utilities has posted certain letters of credit totaling $1.2 million as security for obligations of the Liberty businesses. The terms of the Liberty Facility require Liberty Utilities to pay a standby charge calculated as one quarter of the current stamping fee on the unused portion of the Liberty Facility and maintain certain financial covenants.

Liberty Utilities manages its operational cash flow and its availability under the Liberty Facility to meet such payment obligations. If the Liberty Facility goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their rights to accelerate Liberty Utilities repayment obligations under the facility.

4.2 Operational Risk Management

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC Businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter.

(a) Mechanical and Operational Risks

APUC is entirely dependent upon the operations and assets of each of APUC's Businesses. Accordingly, dividends to shareholders are dependent upon the profitability of each of APUC's Businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

APCo

APCo's existing long term PPAs minimize the risk of reductions in average energy pricing across its portfolio of facilities.

Liberty Utilities (South)

Liberty Utilities (South)'s profitability could be impacted by equipment failure at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards.

The water distribution networks operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

These risks are mitigated through the geographic diversification of water distribution operations, and the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. U.S. governmental authorities have the ability to impose restrictions on water usage during drought conditions. If imposed, this could result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Liberty Utilities (West)

Electricity distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down by high winds, tree branches, and even complete trees with the attendant risk to individuals and property. In addition, in forested areas during dry weather years, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

These forest fire risks are mitigated through the use of regular vegetation management and line maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses.

US governmental authorities have the ability to impose restrictions on electricity usage during periods of power generation disruption and loss of adequate transmission capability. If imposed, this could result in decreased demand for electricity, even if supplies are adequate, which could adversely affect revenues and earnings.

(b) Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its financial statements.

APCo

Generally, APCo's hydroelectric facilities are subject to some form of a water use agreement. The terms of these agreements vary by facility as they are agreements made with the local government body that regulates electrical energy generators and can extend over many years. Certain of the agreements contain clauses which allow the regulating body the option to require APCo to decommission the facility upon the expiry or termination of the agreements. Other facilities have no specific obligations other than to maintain the facility in good working order. APCo has options in many of its existing water use agreements to renew or extend the agreements and anticipates being in a position to extend the majority of its agreements and continue to operate its facilities. Based on historical general practice within the regions in which APCo has facilities, APCo has assessed the probability of being required to decommission a facility upon the expiry of a water use agreement to be remote. As such, any potential asset retirement obligation expense has been assessed as insignificant as the obligation would be incurred well into the future and there is a remote likelihood of being required to decommission a facility.

The St. Leon Facility does not own the property on which its turbines are located. In 2004, St. Leon entered into long-term right-of-way agreements with land owners which allowed it to construct and maintain the wind turbines used by the facility on their property. These agreements are for minimum terms of 40 years and, upon expiry or termination, provide the land owners with title to the equipment if it is not decommissioned by APCo at its option. While APCo anticipates being in a position to renew or extend the existing PPA in 2025, in the event that APCo is unable to renew or extend the agreement, or identify another purchaser of the energy, APCo may choose to decommission the facility. APCo has assessed there to be a remote likelihood of incurring any cost to decommission the wind farm.

The EFW Facility owns the property on which its facility operates. EFW's current waste incineration agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility.

While APCo anticipates being in a position to renew or extend the existing contract in 2012, in the event that APCo is unable to renew or extend the agreement, APCo may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

Liberty Utilities (South)

Liberty Utilities (South)'s water distribution and wastewater collection and treatment utility systems are operated with the assumption that their services will be required in perpetuity and there are no contractual requirements to decommission the entire facility. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities (South) has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging wastewater treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus Liberty Utilities (South) is allowed to earn a return on its investment

Liberty Utilities (West)

Liberty Utilities (West) operates its electrical distribution facilities with the assumption that their services will be required in perpetuity and there are no contractual requirements to decommission the entire facility. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities (West) has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging electricity distribution facilities and expenses associated with providing new sources of electricity can generally be included in the facility's rate base and thus Liberty Utilities (West) is allowed to earn a return on its investment.

(c) Environmental Risks

APCo

The APCo Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric facility include possible dam failure which results in upstream or downstream flooding and equipment failure which result in oil or other lubricants being spilled into the waterway. In addition, the operation of a hydroelectric facility may cause the water in the associated waterway to flow faster, or slower, which could result in water flow issues which impact fish population, water quality and potential increases in soil erosion around a dam facility. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility. Federal regulators in the U.S. inspect certain hydroelectric facilities on an annual basis and complete an environmental inspection every 3-5 years.

The primary environmental risks associated with the operation of a wind farm include potential harm to the local and migratory bird population, potential harm to the local bat population as well as concerns over noise levels and visual ‘harm’ to the scenic environment around the wind farm. As part of the federal and provincial approval of the St. Leon wind project, certain pre-construction and post construction monitoring studies were required. No significant issues were identified as a result of these studies. In order to monitor and mitigate these risks, APCo completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility.

The APCo Thermal Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a cogeneration facility include potential air quality and emissions issues, soil contamination resulting from oil spills and issues around the storage and handling of chemicals used in normal operations. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs regular stack testing and tests the calibration of monitoring equipment. The primary environmental risks associated with the operation of an incineration facility include potential air quality, odour and emissions issues, soil contamination resulting from oil or other chemical spills and issues around the storage and handling of municipal solid waste. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, APCo maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

Liberty Utilities (South)

Liberty Utilities (South)’s water distribution and wastewater collection and treatment utility systems face a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a wastewater treatment facility include potential air quality and odour management issues, wastewater spills and surface and ground water contamination.

In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Utilities (South) maintains ongoing sampling and testing programs as required in its operational jurisdiction, including annual field investigations by management. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the wastewater collection system and at the wastewater treatment plants that it operates.

The primary environmental risks associated with the operation of a water distribution facility include risk of groundwater contamination by contaminants such as bacterial, synthetic, organic and inorganic pollutants, consumption and availability of groundwater and ensuring water quality continues to meet and exceed Environmental Protection Agency ("**EPA**") and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Liberty Utilities (South) maintains a regular sampling and testing program as required in its operational jurisdiction. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the water distribution systems that it operates.

Federal drinking water legislation in the United States requires all drinking water systems to meet specific standards. The costs of complying with drinking water standards form part of a facility's rate case applications.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

Liberty Utilities (West)

Liberty Utilities (West) faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities (West) generates some hazardous wastes as a result of its electrical distribution operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities (West) promptly investigates all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation

(d) Cycles and Seasonality Risk

Please see "*Description of the business – Cycles and Seasonality*" for a detailed description and discussion of this risk.

(e) Specific Environmental Risks

(i) **APCo—Greenhouse Gas Initiatives – Power Generation**

Several north-eastern U.S. States have formed a coordination group to develop a multi-state green house gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative ("**RGGI**"), has received backing from states where APCo operates facilities including Connecticut. RGGI drafted a model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program will be implemented to regulate CO_2 emissions from large electrical generation facilities, including the Windsor Locks Facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks Facility is the only APCo site that is currently affected by the RGGI regulations. As such APCo will be required to purchase approximately 250,000 tons of CO_2 allowances per year, equivalent to the total annual CO_2 emissions from the Windsor Locks facility for the 2009 to 2012 fiscal years. APCo is entitled to apply for allowances and/or purchase allowances at a base price of $2.00 per tonne from the state of Connecticut. APCo submitted an application on October 31, 2008 for allowances under the available programs. For 2012, APCo has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks Facility to be between $0.2 and $0.4 million.

RGGI has been in effect in CT since 2009. The first compliance period is from January 2009 to December 2011. For 2012, it is estimated that the Facility will produce 100,000 tons of CO_2, obtain allowances of 55,000 tons through the UTSA, and be required to purchase an additional 55,000 tons to comply with RGGI by the end of December. The current price for RGGI allowances is approximately $1.90/ton.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called the Western Climate Initiative. Each member state/province is now responsible for developing the draft design of the Regional Cap-and-Trade Program and taking the necessary steps to implement the Program within its jurisdiction. APCo owns and operates the Sanger Facility in California and the EFW Facility in Ontario and holds investments in two others in Ontario which could be impacted by this program.

The EFW Facility submitted the first GHG report under the Ontario Regulation 452/09 in June 2011. In the future, APEFW will also be required to purchase emissions allocations based on emissions reported for the 2010 and/or subsequent periods, depending on the timing for the implementation of the Provincial Cap-and-Trade program, still under final design and approval.

The State of California is the first member of the WCI to implement a Cap-and-Trade program. This program started on January 1, 2012, with the first enforceable compliance obligation beginning with the 2013 GHG emissions. Under this program, independent power generation facilities are not eligible for direct/free credits allocations, as such, the Sanger Facility will have to make provisions to purchase allowances.

On December 15, 2011, Québec announced the adoption of the cap-and-trade system for greenhouse gas emission allowances, which is based on the rules established by the WCI. The first year of implementation of the system will be a transition year. It will begin on January 1, 2012 and will allow emitters and participants to familiarize themselves with how the system works. Over the course of the year, emitters will also be able to make any adjustments that may be necessary to meet their obligations under the system for capping and reducing GHG emissions, which will come into force on January 1, 2013.

The Carbon Disclosure Project ("**CDP**") is an independent non-profit organization that represents institutional investors managing over $57.0 trillion of assets. The CDP is specifically working to encourage companies worldwide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both potential physical impacts and regulatory changes that may result in an effort to address climate change.

APCo submitted a baseline greenhouse gas emissions inventory to the CDP for 2008, 2009 and 2010. The inventory is presently being done for 2011. The emissions data includes both direct emissions from our processes as well as indirect emissions from purchased power. The emissions inventory has been developed based on guidance from the Greenhouse Gas Protocol. This submission will allow comparisons with other firms to be made, and will also be useful as a baseline for addressing climate change regulations. Results are available on the CDP website.

(ii) **APCo—Greenhouse Gas Initiatives – Renewable Energy**

As a result of certain legislation passed in Québec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Québec.

The province of Ontario is considering enacting new legislation similar to Bill C93. APCo operates four hydroelectric facilities in Ontario. While it is too early to assess the costs of compliance, it is possible that modifications to certain dam structures may be required in order to be compliant with any new regulations should they come into effect. Any capital costs associated with the anticipated modifications are expected to be significantly lower than the expected capital costs related to the Québec Facilities, as there are fewer facilities in Ontario and they are of newer construction.

(iii) **Liberty Utilities (South)**

The Litchfield Park Facility operates where groundwater pollutants, namely trichloroethylene ("**TCE**") originally employed by a former aerospace manufacturing plant in the nearby City of Goodyear, are progressing toward three of the twelve wells that provide water to the Litchfield service area. The EPA began monitoring TCE in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA regular technical meetings in regards to this monitoring program, the Litchfield Park Facility closely monitors its wells for this groundwater pollutant through the sampling and testing of water from wells that are potentially at risk of contamination.

To date there have not been any detectable levels of TCE in the water from wells used by the Litchfield Park Facility. EPA's monitoring and control efforts have begun to show reducing concentrations in monitoring wells associated with the northeastern portion of the plume, closest to the Litchfield Park Facility wells. Remedial efforts are currently being intensified in the northwestern portion of the plume in order to ensure full capture of the plume. Additional remedial efforts by the EPA to stop advancement and reduce TCE concentrations are continuing. In the event that any wells exceed the EPA permitted TCE level, the Litchfield Facility would undertake the appropriate actions which may include installing appropriate treatment facilities or removing the well from the water distribution system of the utility. In the event of removal of a well, there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of the Litchfield Park Facility's customers.

In addition, the Litchfield Park Facility has identified alternate sites where replacement wells can be established to replace this potential lost capacity. The cost of establishing a new well is estimated to be between U.S $2.0 million and U.S. $3.5 million depending on the location, depth and other factors. The cost of commissioning a well forms part of the rate base for the utility. Other factors that can impact the cost of a well include, but are not limited to, any requirement to construct wellhead treatment for pollutants, proximity of newly constructed well to water distribution lines, volume of water available at the new site, and acquisition of land and groundwater rights. Liberty Utilities (South) does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

The Company's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2011.

(iv) **Regimes that Could Impact APUC**

APCo

As a result of certain legislation passed in Quebec (Bill C93), APCo is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. See "*Specific Environmental Risks*" under "*Risk Factors*".

Liberty Utilities (West)

The State of California is considering legislation that will increase the Renewable Portfolio Standards to 33% from the current 20% by the year 2020 which could impact the source of electricity for Calpeco. Any increases in cost of electricity will be passed on the ratepayers through the General Rate Case process.

(v) **Regimes that Could Benefit APUC**

The US Federal government has committed to implementing a US carbon reduction strategy, and has included revenue from a federal carbon cap-and-trade program in future budget projections. Similarly, the Canadian federal and provincial governments have indicated increased support for Canadian participation in an integrated North American climate change program.

APUC believes that with its existing portfolio of renewable energy and high efficiency cogeneration Facilities the Power Generation business unit is ideally situated to benefit from an improved competitive position within the North American power sector.

In addition, the US Federal government is currently debating the implementation of a country-wide Renewable Energy Portfolio Standard. This would increase the market demand for renewable energy and broaden the opportunities for development of renewable energy projects.

In conjunction with the development of cap and trade programs and working to increase the supply of renewable energy, various North American governments are making legislative and regulatory changes to streamline the approvals process for the development of new renewable energy projects.

(f) Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various lawsuits, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

APCo

As discussed below under "*Legal Proceedings and Regulatory Actions – Legal Proceedings*", APCo and Algonquin Power Corp. ("APC"), an affiliate of APMI, are involved in civil proceedings and bankruptcy proceedings with Trafalgar. As also discussed in that section, the Attorney General of Québec ("**Québec AG**") filed suit claiming that an Algonquin entity had been paying to the federal authority under its water lease. Both proceedings have gone to the appeal stage. On the Trafalgar civil proceedings file, the claims against APCo were dismissed on appeal, and the bankruptcy proceedings continue. On the Côte Ste-Catherine Water Lease Dues file, the appeal was heard in January 2011 and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

(g) Tax Related Risks

Although APUC is of the view that all expenses being claimed by APUC are reasonable and that the cost amount of APUC's depreciable properties have been correctly determined, there can be no assurance that Canada Revenue Agency or the Internal Revenue Service will agree. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to shareholders.

(h) Tax Risks Associated with the Unit Exchange

There is a possibility that the Canada Revenue Agency could successfully challenge the tax consequences of the Unit Exchange or prior transactions of the Corporation or that legislation could be enacted or amended resulting in different tax consequences from those contemplated in the Unit Exchange for APUC. While APUC is confident in its position, such a challenge or legislation could potentially and materially affect the availability or amount of the tax attributes or other tax accounts of APUC.

(i) Obligations to Serve

APCo

APCo is not subject to obligations to serve.

Liberty Utilities

Liberty Utilities facilities may be located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Utilities (South) and Liberty Utilities (West) may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

4.3 Regulatory Climate and Permitting Risks

Profitability of APUC Businesses is in part dependant on regulatory climates in the jurisdictions in which it operates.

APCo

In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue. The failure to obtain all necessary licences or permits, including renewals thereof or modifications thereto, may adversely affect cash generated from operating activities.

In the United States, FERC issues licences for the construction, operation and maintenance of electrical generating facilities. Facilities are required to be licenced or have valid exemptions from FERC. Failure to maintain such licences, including amendments or modifications thereto, may result in the owner being unable to operate the licenced facility and could adversely affect cash generated from operating activities.

The US Thermal Facilities obtain certain benefits and exemptions because of their Qualifying Facility status ("**QF Status**") under PURPA. If any facility were to lose its QF Status, the Facility would no longer be entitled to the exemptions and benefits thereof. Loss of QF Status may also require the Facility to cease selling electricity at the rates set forth in the existing PPAs to the extent they exceed current short run Avoided Costs. Under certain circumstances, loss of QF Status on a retroactive basis could lead to, among other things, claims by an electrical utility's end user customers for a refund of payments previously made.

Liberty Utilities (South)

Liberty Utilities (South) water distribution and wastewater collection and treatment utility systems are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Water and wastewater utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities (South), and while Liberty Utilities (South) believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Utilities (South) regularly works with these authorities to manage the affairs of the business.

Liberty Utilities (West)

Liberty Utilities (West)'s facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities (West), and while Liberty Utilities (West) believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Utilities (West) regularly works with these authorities to manage the affairs of the business.

4.4 Dependence upon APUC Businesses

APUC

Liberty Utilities has reduced its dependence on APUC through initiatives such as obtaining a senior unsecured revolving credit facility, the Liberty Facility, issuing long term debt directly on its own and placement of regional presidents to oversee operations. APUC is entirely dependent upon the profitable operations and assets of other APUC Businesses in order to acquire funding for future growth acquisitions. Accordingly, dividends to shareholders are dependent upon the ability of each of the APUC Businesses to pay principal and interest on the notes issued by it and to declare and pay dividends.

APCo

The profitability of APCo may be affected by expiry of the present long-term PPAs to which certain of APCo's subsidiaries are a party.

Liberty Utilities

US governmental authorities have the ability to impose restrictions on water and electricity usage during periods of drought or power generation disruption and loss of adequate transmission capability, respectively. If imposed, this could result in decreased demand for water and electricity, even if supplies are adequate, which could adversely affect revenues and earnings.

Water and electricity distribution and wastewater treatment facilities could also be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities (South) and Liberty Utilities (West), and while both Liberty Utilities (South) and Liberty Utilities (West) believe it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

4.5 Safety Considerations

The operation of the facilities require adherence to safety standards imposed by regulatory bodies. Failure to operate the facilities in strict compliance with these regulatory standards may expose the Facilities to claims and administrative sanctions. To mitigate the risk of administrative sanctions and to minimize safety risks to employees and contractors, APUC works continuously with all employees to ensure the development and implementation of a progressive, proactive safety culture within all operations. APUC has multiple active safety committees operating with each operating unit and has a dedicated staff to ensure that the existing safety program is continuously improving.

4.6 Labour Relations

While labour relations have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment cannot be assured.

APCo

With the exception of the EFW Facility and the Tinker Facility, employees of APCo and their material subcontractors are non-unionized. The EFW Facility is unionized and a new collective bargaining agreement was renegotiated in 2011 for a term of three years, until April 2014. The Tinker Facility is unionized and a new collective bargaining agreement was renegotiated in January 2011 for a term of five years.

Liberty Utilities (South)

All employees of Liberty Utilities (South) and their material subcontractors are non-unionized.

Liberty Utilities (West)

All employees of Liberty Utilities (West) are non-unionized with the exception of 49 employees at the California Utility. The California Utility is unionized and the current collective bargaining agreement was renegotiated in August 2010 for a term of three years, until August 2013.

4.7 Dependence Upon Key Customers

APCo

The customers that currently purchase APUC's Facilities are primarily large utilities. See the summaries of the contracts in Schedules A, B, C and D. If, for any reason, such customers were unable to fulfill their contractual obligations under the PPAs, cash flow available to Shareholders would decline.

Liberty Utilities (South)

The customers of Liberty Utilities (South) water and wastewater utilities are primarily residential. Large commercial and industrial customers make up less than 24% of gross revenues, with no single customer making up more than 2.4% of gross revenues. As such, the Company has minimal dependence upon a few key customers.

Liberty Utilities (West)

The customers that currently purchase from Liberty Utilities (West) facilities are primarily residential. Large commercial accounts make up less than 20% of gross revenues, with no single customer making up more than 3.6% of gross revenues. As such, the Company has minimal dependence upon a few key customers.

4.8 Potential Conflicts of Interest

As discussed in "*Three Year History – Fiscal 2009*" above, an agreement was reached on December 21, 2009 to internalize management. Unitholders had previously been dependent on APMI for the administration of APCo and for management and operation of the Facilities. Since December 21, 2009, management of Algonquin has been conducted by officers of APUC. There may be situations in which conflicts of interest may arise between the Senior Executives of APUC in relation to the interests of APUC. Transactions involving related parties, including the Senior Executives who are principals of APMI, are disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the period ended December 31, 2011.

4.9 Construction / Development Risk

Successful development of wind and other energy projects are subject to significant risks and uncertainties including those relating to the ability to obtain financing on acceptable terms, currency fluctuations affecting the cost of major capital components such as turbines, price escalation for construction labour and other construction inputs, construction risk that the project is built with mechanical defects, is not completed on time and is not within budget estimates.

4.10 Acquisitions and Divestitures

Acquisitions of complementary businesses and technologies are a part of APUC's overall business strategy. In spite of the complementary nature of any businesses or technologies acquired, there is always a risk that services, technologies, key personnel or businesses of acquired companies may not be effectively assimilated into APUC's business or service offerings. Similarly, divestitures of businesses that are no longer viewed as being strategic to APUC's continuing operations can be an active part of APUC's overall business strategy. Divestitures may result in a reduction in total revenues and net income.

APCo and Liberty Utilities each have a Transition Management Office ("**TMO**") that have developed standard project management and governance processes to manage its respective company integrations due to acquisitions. These processes ensure an effective organization of people, resources and time frames for a successful integration of technology, operations, asset management and business processes. The TMO uses a sound governance reporting structure which includes the participation of APCo and Liberty Utilities senior management to ensure that the respective operations and processes are implemented in a timely and efficient manner. The governance process also includes a transparent issue resolution process which is documented and reported throughout APCO and Liberty Utilities.

5. DIVIDENDS

The total amount of dividends declared for fiscal 2009, 2010 and 2011 were $19.3, $22.8 million and $32.4 million, respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2009, 2010 and 2011 were $0.24, $0.24 and $0.27, respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective August 11, 2011, the Board established a quarterly dividend of $0.07 or $0.28 annually.

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time in its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors noted above. See "*Risk Factors*".

5.1 Dividend Reinvestment Plan

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the "**Reinvestment Plan**") which will be offered to registered holders of Common Share ("**Shareholders**") of APUC.

The purpose of the Reinvestment Plan is to enable Shareholders to invest all cash dividends on Common Shares in additional shares of APUC ("**Plan Shares**"). All such Plan Shares will be, at APUC's election, either (i) Common Shares purchased on the open market through the facilities of the TSX ("Market Purchase") or (ii) newly issued Common Shares purchased from APUC ("**Treasury Purchase**").

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the Agent for all Plan Shares purchased in respect of a Dividend Payment Date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Common Shares on TSX for the five (5) trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC's election. No commissions, service charges or brokerage fees are payable by Shareholders in connection with the Reinvestment Plan.

As at December 31, 2011, 23.6 million Common Shares had been registered with the Reinvestment Plan.

6. DESCRIPTION OF CAPITAL STRUCTURE

6.1 Common Shares

APUC may issue an unlimited number of Common Shares. The holders of Common Shares are entitled to dividends, if and when declared; to one vote for each Common Shares at meetings of the holders of Common Shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All Common Shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

As at December 31, 2011, APUC had 136,122,780 issued and outstanding Common Shares. Following the Series 2A Redemption, APUC had 146,741,635 Common Shares outstanding.

As at December 31, 2011, the 12.0 million subscription receipts issued to Emera pursuant to the Subscription Agreement (National Grid) convertible into 12.0 million Common Shares was outstanding. Delivery of the Common Shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost to acquire Granite State and EnergyNorth.

On April 29, 2011, pursuant to the Strategic Agreement, Emera and APUC agreed to the general terms by which Emera would sell its 49.999% direct ownership in the California Utility to APUC, with closing of such transaction subject to, among other things, execution of a definitive purchase agreement and regulatory approval. On September 12, 2011, Emera US Holdings Inc., a subsidiary of Emera through which it holds its interest in the California Utility, entered into a definitive purchase agreement with Liberty Utilities. In connection with this transaction, Emera entered into a subscription agreement dated September 12, 2011 (the "**Subscription Agreement (Calpeco)**") with APUC, pursuant to which Emera subscribed for an aggregate of 8,211,000 subscription receipts from APUC price of $4.72 per subscription receipt. Payment for these subscription receipts was satisfied by delivery by Emera of two non-interest bearing promissory notes, one in the amount of $22,608,800 and one in the amount of $16,147,120. The proceeds of this subscription receipt transaction will be used to fund the acquisition by Liberty Utilities of Emera US Holdings Inc.'s interest in the California Utility. 4,790,000 subscription receipts will convert into APUC shares on a one-for-one basis following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012), at which time the $22,608,800 promissory note delivered by Emera to APUC to satisfy the subscription price of the first tranche of subscription receipts become due and payable. The remaining 3,421,000 subscription receipts will convert into APUC shares on a one-for-one basis following completion of the California Utility's first rate case, expected to be completed in early 2013, at which time the $16,147,120 promissory note delivered by Emera to APUC to satisfy the subscription price of the second tranche of subscription receipts become due and payable. In the event of termination of the Subscription Agreement (Calpeco), the promissory notes will be returned to Emera for cancellation, the subscription receipts will be returned to APUC for cancellation, and the parties will have no further obligations under the Subscription Agreement (Calpeco).

On April 30, 2011, APUC committed to issuance to Emera of a treasury subscription of subscription receipts convertible into approximately 6.9 million APUC common shares upon closing of the transaction related to the acquisition of an interest in a portfolio of 370MW wind projects. APUC intends to cancel this treasury subscription as it announced on January 27, 2012 that it no longer intended to proceed with the First Wind acquisition.

6.2 Preferred Shares

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. APUC does not have any issued and outstanding preferred shares.

6.3 Convertible Debentures

APUC currently has outstanding series of convertible debentures:

- a principal amount of $62,800 Series 3 Debentures.

If all of the principal amount of the Series 3 Debentures were converted by the holders thereof, an additional 14,882,142 Common Shares will be issued pursuant to the terms of the trust indenture (the "**Series 3 Trust Indenture**") dated as of December 2, 2009 between APUC and the Debenture Trustee.

(a) Series 1A Debentures

On October 27, 2009, the Corporation issued, in connection with the Unit Exchange, an aggregate of $66,942,750 principal amount of 7.50% convertible unsecured subordinated debentures due November 33, 2014 (the "**Series 1A Debentures**").

On April 7, 2011, APUC provided the holders of its Series 1A Debentures with notice of its intention to redeem for equity, all of the issued and outstanding Series 1A Debentures. Prior to the Redemption Date, a principal amount of $60,339,000 of Series 1A Debentures were converted into 14,788,975 Common Shares. On the Redemption Date, APUC issued and delivered 430,666 Common Shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradeable Common Shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of Common Shares on the Redemption Date.

As a result of the Redemption there were no Series 1A Debentures outstanding subsequent to the Redemption Date.

(b) Series 2A Debentures

On October 27, 2009, the Corporation issued, in connection with the Unit Exchange, an aggregate of $59,967,000 principal amount of Series 2A Debentures.

On January 20, 2012, APUC provided the holders of its Series 2A Debentures notice of its intention to redeem for equity, effective on the Series 2A Redemption Date (February 24, 2012), all of the issued and outstanding Series 2A Debentures. Prior to the Series 2A Redemption Date, $2,916,000 principal amount of Series 2A Debentures were converted by debentureholders into 485,998 Common Shares.

On the Series 2A Redemption Date, APUC issued and delivered 9,836,520 APUC shares to the remaining holders of Series 2A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures of $57,041,000, by 95% of the current market price of Common Shares on the Series 2A Redemption Date.

As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

(c) Series 3 Debentures

On December 2, 2009, APUC issued $63,250,000 principal amount of Series 3 Debentures. The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year. As at March 15, 2012, there were $62,505,000 principal amount of Series 3 Debentures outstanding.

APUC may, from time to time, without the consent of the holders of the APUC Debentures, issue additional debentures. For a complete description of the APUC Debentures, reference should be made to the Trust Indenture and the Series 3 Trust Indenture, copies of which are available on www.sedar.com.

(i) Conversion Privilege

The Series 3 Debentures are convertible at the holder's option into fully paid, non-assessable and freely tradeable Common Shares at any time prior to 5:00 p.m. (Toronto time) on the earlier of June 30, 2017 (the "**Series 3 Maturity Date**") and the business day immediately preceding the date specified by APUC for redemption of the Series 3 Debentures, at a conversion price of $4.20 per Common Share (the "**Series 3 Conversion Price**") being a ratio of approximately 238.1 Common Shares per $1,000 principal amount of Series 3 Debentures. The Series 3 Debentures bear interest from the date of issue at 7.0% per annum, which will be payable semi-annually on June 30 and December 31 in each year, commencing on June 30, 2010 (each, a "**Series 3 Interest Payment Date**").

Interest will be payable based on a 365-day year. At the option of APUC, subject to applicable law, APUC may deliver Common Shares to its agent who shall sell such Common Shares on behalf of APUC in order to raise funds to satisfy all or any part of APUC's obligations to pay interest on the APUC Debentures, but in any event, the holders of APUC Debentures shall be entitled to receive cash payments equal to the interest otherwise payable on the APUC Debentures.

No adjustment will be made for dividends on Common Shares issuable upon conversion or for interest accrued on APUC Debentures surrendered for conversion; however, holders converting their APUC Debentures are entitled to receive, in addition to the applicable number of Common Shares, accrued and unpaid interest in respect thereof for the period up to the date of conversion from the latest Series 3 Interest Payment Date in the case of the Series 3

Debentures. Notwithstanding the foregoing, no Series 3 Debentures may be converted on any Series 3 Interest Payment Date and during the five business days preceding June 30 and December 31 in each year as the registers of the Debenture Trustee are closed during such periods.

Subject to the provisions thereof, the Series 3 Trust Indenture provide for the adjustment of the Series 3 Conversion Price in certain events including: (a) the subdivision or consolidation of the outstanding Common Shares; (b) the distribution of Common Shares to holders of Common Shares by way of distribution or otherwise other than an issue of securities to holders of Common Shares who have elected to receive distributions in securities of APUC in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to holders of Common Shares entitling them to acquire Common Shares or other securities convertible into Common Shares at less than 95% of the then Current Market Price (as defined below under “Payment upon Redemption or Maturity”) of the Common Shares; and (d) the distribution to all holders of Common Shares of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the Series 3 Conversion Price, in respect of any event described in (b), (c) or (d) above if, subject to prior regulatory approval, the holders of APUC Debentures are allowed to participate as though they had converted their APUC Debentures prior to the applicable record date or effective date. APUC will not be required to make adjustments the Series 3 Conversion Price, unless the cumulative effect of such adjustments would change the Series 3 Conversion Price, as the case may be, by at least 1%.

In the case of any reclassification or change (other than a change resulting only from consolidation or subdivision) of the Common Shares or in case of any amalgamation, consolidation or merger of APUC with or into any other entity, or in the case of any sale, transfer or other disposition of the properties and assets of APUC as, or substantially as, an entirety to any other entity, the terms of the conversion privilege shall be adjusted so that each APUC Debenture shall, after such reclassification, change, amalgamation, consolidation, merger or sale, be exercisable for the kind and amount of securities or property of APUC, or such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, change, amalgamation, consolidation, merger or sale if on the effective date thereof it had been the holder of the number of Common Shares into which APUC Debenture was convertible prior to the effective date of such reclassification, change, amalgamation, consolidation, merger or sale.

No fractional Common Shares will be issued on any conversion of APUC Debentures, but in lieu thereof, APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

(ii) Redemption and Purchase

The Series 3 Debentures may not be redeemed by APUC (except in the case of a change of control) on or before December 31, 2012. Thereafter, but prior to December 31, 2014, the Series 3 Debentures may be redeemed at the option of APUC, in whole at any time or in part from time to time, on not more than 60 days’ and not less than 30 days’ prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 3 Conversion Price.

On or after December 31, 2014 and prior to the Series 3 Maturity Date, the Series 3 Debentures may be redeemed by APUC, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

APUC will have the right to purchase APUC Debentures in the market, by tender or by private contract subject to regulatory requirements; provided, however, that if an Event of Default (as defined below) has occurred and is continuing, APUC will not have the right to purchase APUC Debentures by private contract.

In the case of redemption of less than all of APUC Debentures, APUC Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX.

(iii) Payment upon Redemption or Maturity

On redemption or on the Series 3 Maturity Date, as applicable, APUC will repay the indebtedness represented by APUC Debentures which are to be redeemed or which have matured by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding APUC Debentures, together with accrued and unpaid interest thereon. APUC may, at its option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, unless an Event of Default (as defined below) has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of APUC Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Common Shares to the holders of the APUC Debentures. The number of Common Shares to be issued will be determined by dividing the principal amount of the APUC Debentures which are to be redeemed by 95% of the Current Market Price of the Common Shares on the date fixed for redemption or the maturity date, as the case may be. No fractional Common Shares will be issued to holders of APUC Debentures but in lieu thereof APUC shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

The term "**Current Market Price**" is defined in the Series 3 Trust Indenture to mean the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event.

(iv) Cancellation

All APUC Debentures converted, redeemed or purchased as aforesaid will be cancelled and may not be reissued or resold.

(v) Subordination

The payment of the principal of, and interest on, the APUC Debentures is subordinated in right of payment, in the circumstances referred to below and more particularly as set forth in the Trust Indenture, to the prior payment in full of all Senior Indebtedness of APUC. "**Senior Indebtedness**" of APUC is defined in the Series 3 Trust Indenture as all indebtedness of APUC, other than the APUC Debentures and any other debentures issued under the Series 3Trust Debenture, (whether outstanding as at the date of the Series 3 Trust Indenture or thereafter created, incurred, assumed or guaranteed), and including, for greater certainty, claims of trade creditors of APUC, which by the terms of the instrument creating or evidencing the indebtedness, is not expressed to be *pari passu* with, or subordinate in right of payment to, APUC Debentures.

The Series 3 Trust Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation or reorganization in connection with or as a result of an insolvency or bankruptcy proceeding or other similar proceedings relative to APUC, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding up of APUC, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of APUC, all creditors under any Senior Indebtedness will receive payment in full before the holders of APUC Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any APUC Debenture or any unpaid interest accrued thereon.

In addition to the foregoing, pursuant to the terms of the Series 3 Trust Indenture, neither the Debenture Trustee for, nor the holders of, APUC Debentures are entitled to demand or otherwise attempt to enforce in any manner, institute proceedings for the collection of, or institute any proceedings against APUC, including, without limitation, by way of any bankruptcy, insolvency or similar proceedings or any proceeding for the appointment of a receiver, liquidator, trustee or other similar official (it being understood and agreed that the Debenture Trustee and/or the holders of APUC Debentures are permitted to take any steps necessary to preserve the claims of the holders of APUC Debentures in any such proceeding and any steps necessary to prevent the extinguishment or other termination of a claim or potential claim as a result of the expiry of a limitation period), or receive any payment or benefit in any manner whatsoever on account of indebtedness represented by APUC Debentures other than as set forth in the Trust Indenture at any time when (i) an event of default (howsoever designated) has occurred and is continuing under the Senior Credit Facility, or (ii) an event of default (howsoever designated) has occurred under any other Senior Indebtedness and is continuing and, in each case, notice of such event of default has been given by or on behalf of the lender or lenders party to such Senior Indebtedness to APUC or an affiliate thereof that is the borrower pursuant to such Senior Indebtedness (the “**Senior Indebtedness Postponement Provisions**”).

The APUC Debentures are also subordinate to claims of creditors of APUC.

(vi) Put Right upon a Change of Control

Upon the occurrence of a change of control of APUC involving the acquisition of voting control or direction over 66 2/3% or more of the outstanding Common Shares by any person or group of persons acting jointly or in concert (a “**Change of Control**”), each holder of APUC Debentures may require APUC to purchase, on the date which is 30 days following the giving of notice of the Change of Control as set out below (the “**Put Date**”), the whole or any part of such holder’s APUC Debentures at a price equal to 101% of the principal amount thereof (the “**Put Price**”) plus accrued and unpaid interest to the Put Date.

If 90% or more in the aggregate principal amount of APUC Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered for purchase on the Put Date, APUC will have the right to redeem all the remaining APUC Debentures on such date at the Put Price, together with accrued and unpaid interest to such date. Notice of such redemption must be given to the Debenture Trustee prior to the Put Date and as soon as possible thereafter, by the Debenture Trustee to the holders of APUC Debentures not tendered for purchase. The principal on APUC Debentures will be payable in lawful money of Canada or, at the option of APUC and subject to applicable regulatory approval, by payment of Common Shares to satisfy, in whole or in part, its obligation to repay the principal amount of APUC Debentures.

The Series 3 Trust Indenture contains notification provisions to the effect that:

APUC will promptly give written notice to the Debenture Trustee of the occurrence of a Change of Control and the Debenture Trustee will thereafter give to the holders of APUC Debentures a notice of the Change of Control, the repayment right of the holders of APUC Debentures and the right of APUC to redeem un-tendered APUC Debentures under certain circumstances; and

(a) a holder of APUC Debentures, to exercise the right to require APUC to purchase its APUC Debentures, must deliver to the Debenture Trustee, not less than five business days prior to the Put Date, written notice of the holder's exercise of such right, together with a duly endorsed form of transfer.

(b) APUC will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of APUC Debentures in the event of a Change of Control.

(vii) Modification

The rights of the holders of the APUC Debentures as well as any other series of debentures that may be issued under the Series 3 Trust Indenture may be modified in accordance with the terms of the Series 3 Trust Indenture. For that purpose, among others, the Trust Indenture contains certain provisions which will make binding on all holders of APUC Debentures resolutions passed at meetings of the holders of APUC Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the then outstanding APUC Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the then outstanding APUC Debentures. In certain cases, the modification will, instead of or in addition to, require assent by the holders of the required percentage of APUC Debentures of each particularly affected series. Under the Series 3 Trust Indenture, the Debenture Trustee has the right to make certain amendments to the Trust Indenture in its discretion, without the consent of the holders of APUC Debentures.

(viii) Events of Default

The Series 3 Trust Indenture provides that an event of default ("**Event of Default**") in respect of the APUC Debentures will occur if certain events described in the Series 3 Trust Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to the APUC Debentures: (i) failure for 15 days to pay interest on the APUC Debentures when due; (ii) failure to pay principal or premium, if any, on the APUC Debentures, whether at maturity, upon redemption, by declaration or otherwise; or (iii) certain events of bankruptcy, insolvency or reorganization of APUC under bankruptcy or insolvency laws. Subject to the Senior Indebtedness Postponement Provisions, if an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall, upon the request of holders of not less than 25% in principal amount of the then outstanding APUC Debentures, declare the principal of (and premium, if any) and interest on all outstanding APUC Debentures to be immediately due and payable.

(ix) Offers for Debentures

The Series 3 Trust Indenture contains provisions to the effect that if an offer is made for APUC Debentures which is a take-over bid for APUC Debentures within the meaning of the Securities Act (Ontario) and not less than 90% of the APUC Debentures (other than APUC Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the APUC Debentures held by holders of APUC Debentures who did not accept the offer on the terms offered by the offeror.

(x) Priority of Debt

The APUC Debentures are direct obligations of APUC and may not be secured by any mortgage, pledge, hypothec or other charge and are subordinated to other liabilities of APUC. The Trust Indenture does not restrict AUC from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its assets to secure any indebtedness.

6.4 Employee Share Purchase Plan

In September 2011, APUC approved an employee share purchase plan ("**ESPP**"). Eligible employees may have a portion of their earnings withheld to be used to purchase common shares of APUC. APUC will match up to 20% of an employee's contribution amount for the first $5,000 contributed annually and 10% of an employee's contribution amount for contributions over $5,000 and up to $10,000 annually. Shares purchased through the APUC match portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at December 31, 2011, a total of 7,176 shares had been issued under the ESPP. For the year ended December 31, 2011, APUC recorded $9 in compensation expense.

6.5 Directors Deferred Share Units

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("**DSU**") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one APUC common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period.

As at December 31, 2011, no DSUs had been issued.

6.6 Performance Share Units

In October 2011, APUC issued 28,370 performance share units ("**PSUs**") to certain members of management other than senior executives as part of APUC's long-term incentive program. At the end of the three-year performance periods, the number of shares vested can range from 0% to 144% of the number of PSUs granted. Dividends accumulate during vesting period and are converted to PSUs based on the market value of the shares on that date. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

6.7 Shareholders' Rights Plan

The Rights Plan is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the board of directors of the Corporation and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. The Rights Plan was approved by shareholders at the Meeting until the termination of the annual general meeting of the Shareholders of APUC in 2013 or its termination under the terms of the of Rights Plan. The Rights Plan is similar to rights plans adopted by many other Canadian corporations. Until the occurrence of certain specific events, the rights will trade with the Common Shares of APUC and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Rights Plan, a Permitted Bid is a bid made to all shareholders for all of their Common Shares on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent of the outstanding Common Shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Common Shares but must extend the bid for a further ten days to allow all other shareholders to tender.

6.8 Stock Option Plan

The Corporation implemented a stock option plan (the "**Stock Option Plan**") in 2010. The purpose of the Stock Option Plan is to attract, retain and motivate persons as key service providers to the Corporation and its affiliates and to advance the interests of the Corporation by providing such persons with the opportunity, through share options, to acquire a proprietary interest in the Corporation.

The Stock Option Plan authorizes the Board to issue stock options (“**Options**”) to directors, officers or employees of the Corporation or any affiliate (an “**Eligible Individual**”), a corporation controlled by an Eligible Individual or any person/company, partnership, trust or corporation engaged to provide management or consulting services for the Corporation or any affiliate (“**Eligible Persons**”).

The aggregate number of Common Shares that may be reserved for issuance under the Stock Option Plan must not exceed 10% of the number of Common Shares outstanding at the time the Options are granted. For greater clarity, the Stock Option Plan is “reloading” in the sense that, to the extent that Options expire or are terminated, cancelled or exercised, the Corporation may make a further grant of Options in replacement for such expired, terminated, cancelled or exercised Options, provided that the 10% maximum is not exceeded. No fractional Common Shares may be purchased or issued under the Stock Option Plan.

In addition, under the Stock Option Plan:

- subject to the terms of the Stock Option Plan, the number of Common Shares subject to each Option, the exercise price of each Option, the expiration date of each Option, the extent to which each Option vests and is exercisable from time to time during the term of the Option and other terms and conditions relating to each Option will be determined by the Board from time to time;
- subject to any adjustments pursuant to the provisions of the Stock Option Plan, the exercise price of any Option shall in no circumstances be lower than the Market Price (as defined below) of the Common Shares on the date on which the Board approves the grant of the Option;
- Options will be personal to the grantee and will be non-transferable and non-assignable, except in certain limited circumstances;
- the maximum number of Common Shares which may be reserved for issuance to insiders under the Stock Option Plan, together with the number of Common Shares reserved for issuance to insiders under any other securities based compensation arrangement, shall be 10% of the Common Shares outstanding at the time of the grant;
- the maximum number of Common Shares which may be issued to insiders under the Stock Option Plan and all other security based compensation arrangements within a one year period shall be 10% of the Common Shares outstanding at the time of the issuance;
- non-employee director participation in the Stock Option Plan is limited to the lesser of (i) a reserve of 1% of the Common Shares outstanding for non-employee directors as a group and (ii) an annual equity award value of $100,000 per director;
- if the expiration date for an Option occurs during a Blackout Period (as defined below) or within 10 business days after the expiry date of a Blackout Period applicable to a person granted Options (an “**Optionee**”), then the expiration date for that option will be extended to the 10th business day after the expiry date of the Blackout Period. A “**Blackout Period**” is a period of time of time during which the Optionee cannot exercise an Option, or sell Common Shares issuable pursuant to the exercise of Options, due to applicable policies of the Corporation in respect of insider trading); and
- except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

Under the Stock Option Plan, “**Market Price**” of the Common Shares is defined as the volume weighted average trading price of such Common Shares on the TSX (or, if such Common

Shares are not then listed and posted for trading on the TSX, on such stock exchange in Canada on which such Common Shares are listed and posted for trading as may be selected for such purpose by the Board) for the five (5) consecutive trading days immediately preceding such date, provided that in the event that such Common Shares did not trade on any of such trading days, the Market Price will be the average of the bid and ask prices in respect of such Common Shares at the close of trading on all of such trading days and provided that in the event that such Common Shares are not listed and posted for trading on any stock exchange, the Market Price will be the fair market value of such Common Shares as determined by the Board in its sole discretion.

The Stock Option Plan provides that, except as set out in the Stock Option Plan or any resolution passed at any time by the Board or the terms of any option agreement or employment agreement with respect to any Option or an Optionee, an Option and all rights to purchase Common Shares pursuant thereto shall expire and terminate immediately upon the Optionee who holds such Option ceasing to be an Eligible Person.

Where an Optionee (other than a service provider) resigns from the Corporation or is terminated by the Corporation for cause, the Optionee’s unvested options shall immediately be forfeited and the Optionee’s vested options may be exercised for a period of 30 days after the date of resignation or termination.

Where an Optionee (other than a service provider) retires from the Corporation or ceases to serve the Corporation or an affiliate as a director, officer or employee for any reason other than a termination by the Corporation for cause, the Optionee’s unvested options may be exercised within 90 days after such retirement or termination. The Board may in such circumstances accelerate the vesting of unvested Options then held by the Optionee at the Board’s discretion.

In the event that an Optionee, other than a service provider, has suffered a permanent disability, Options previously granted to such Optionee shall continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Stock Option Plan, but no additional grants of Options may be made to the Optionee.

If an Optionee, other than a service provider, dies, all unexercised Options held by such Optionee at the time of death immediately vest, and such Optionee’s personal representatives or heirs may exercise all Options within one year after the date of such death.

All Options granted to service providers shall terminate in accordance with the terms, conditions and provisions of the associated option agreement between the Corporation and such service providers, provided that such termination shall occur no later than the earlier of (i) the original expiry date of the term of the Option and (ii) one year following the date of termination of the engagement of the service provider.

Options may be exercised in accordance with the specific terms of their grant and by the Optionee delivering the exercise price to the Corporation for all of the Options exercised. The Optionee may also surrender Options and receive in exchange for each such Option, the amount by which the Market Price of the Common Shares exceeds the exercise price of the Option (the "**In-the-Money Amount**"). If the Optionee elects to surrender any Options in exchange for the In-the-Money Amount, the Corporation will determine whether to pay such amount in cash or in Common Shares representing the equivalent of the In-the-Money Amount based on the Market Price of the Common Shares at the date of exercise, in each case net of an amount equal to any withholding taxes.

In the event that the Common Shares are at any time changed or affected as a result of the declaration of a stock dividend, a Share subdivision or consolidation, the number of Common Shares reserved for Option shall be adjusted accordingly by the Board to such extent as it deems proper in its discretion.

If, after the grant of an Option and prior to its expiry:

(i) the Common Shares are reclassified, reorganized or otherwise changed (a "**Share Reorganization**"), otherwise than as specified in the immediately preceding paragraph, or

(ii) subject to the Corporation's right to allow the exercise of vested and unvested Options following the occurrence of certain transactions, the Corporation shall consolidate, merge or amalgamate with or into another corporation (a "**Merger**", with the resulting corporation being the "**Successor Corporation**"),

the Optionee will receive, upon the subsequent exercise of his or her Options in accordance with the Stock Option Plan, the number of Common Shares or securities of the appropriate class of the Corporation or Successor Corporation, as the case may be, that the Optionee would have received if on the record date of such Share Reorganization or Merger the Optionee were the registered holder of the number of Common Shares to which the Optionee was prior thereto entitled to receive on exercise of his or her Options.

The Board may amend, suspend or discontinue the Stock Option Plan or amend Options granted under the Stock Option Plan at any time without shareholder approval; provided, however, that:

(a) approval by a majority of the votes cast by shareholders present and voting in person or by proxy at a meeting of shareholders of the Corporation shall be obtained for any:

   (i) amendment for which, under the requirements of the TSX or any applicable law, shareholder approval is required;

   (ii) reduction of the Option price, or cancellation and reissuance of Options or other entitlements, of non-insider Options granted under the Stock Option Plan;

   (iii) extension of the term of Options beyond the original expiry date of non-insider Options;

   (iv) change in Eligible Persons that may permit an increase to the limit imposed on non-employee director participation set out in the Stock Option Plan;

(v) allowance of Options granted under the Stock Option Plan to be transferable or assignable other than for estate settlement purposes; or

(vi) amendment to the Stock Option Plan's amendment provisions; and

(b) the consent of the Optionee is obtained for any amendment which alters or impairs any Option previously granted to an Optionee under the Stock Option Plan.

Notwithstanding the other provisions of the Stock Option Plan, if:

(a) the Corporation proposes to amalgamate, merge or consolidate with any other corporation (other than a wholly-owned affiliate) or to liquidate, dissolve or wind-up;

(b) an offer to purchase or repurchase all of the Common Shares shall be made to all holders of Common Shares which offer has been approved or accepted by the Board; or

(c) the Corporation proposes the sale of all or substantially all of the assets of the Corporation as an entirety, or substantially as an entirety, so that the Corporation shall cease to operate any active business,

then, the Corporation will have the right, upon written notice thereof to Optionees, to permit the exercise of all such Options, whether or not vested, within the 20 day period next following the date of such notice and to determine that upon the expiration of such 20 day period, all rights of the Optionee to such Options or to exercise same (to the extent not theretofore exercised) shall *ipso facto* terminate and cease to have further force or effect whatsoever.

As of March 30, 2012 the number of outstanding options is 3,681,710, which is 2.5% of the total outstanding Common Shares of the Corporation. The number of Common Shares that have been issued pursuant to the plan is nil.

7. MARKET FOR SECURITIES

7.1 Trading Price and Volume

(a) Common Shares

The Corporation's Common Shares are listed and posted for trading on the TSX under the symbol "AQN". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares and trust units for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000's)
January	5.03	4.73	6,167
February	5.13	4.81	5,018
March	5.42	4.85	5,654
April	5.63	4.98	9,523
May	5.87	5.23	7,487
June	5.86	5.44	5,755
July	5.99	5.59	2,563
August	5.83	4.90	6,599
September	5.85	5.40	4,362
October	5.88	5.47	5,872
November	6.13	5.52	9,249
December	6.59	5.96	22,740

(b) Series 1A Debentures

Series IA Debentures were listed and posted for trading on the TSX under the symbol “AQN.DB”. On the Redemption Date, the remaining Series 1A Debentures were redeemed. As a result, there are no Series 1A Debentures outstanding subsequent to the Redemption Date.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 1A Debentures for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000's)
January	122.79	118.00	58
February	125.50	119.62	16
March	130.70	120.89	29
April	137.52	121.00	191
May 1 -16, 2011	134.65	125.50	33

(c) Series 2A Debentures

Series 2A Debentures were listed and posted for trading on the TSX under the symbol “AQN.DB.A”. On the Series 2A Redemption Date, the remaining Series 2A Debentures were redeemed. As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 2A Debentures for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000's)
January	107.00	106.00	1
February	107.50	106.31	2
March	109.00	106.70	2
April	107.50	107.00	4
May	107.50	106.00	4
June	108.74	106.76	8
July	108.00	106.50	5
August	107.00	102.00	7
September	106.50	104.00	9
October	106.00	103.00	8
November	107.80	104.51	6
December	110.00	104.25	48
January	108.60	102.50	11,000110
February 1 - 24	107.00	102.15	17,006176

(d) Series 3 Debentures

Series 3 Debentures are listed and posted for trading on the TSX under the symbol “AQN.DB.B”. The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 3 Debentures for the periods indicated (as quoted by the TSX).

2011	High ($)	Low ($)	Volume (000's)
January	121.00	115.33	44
February	125.00	118.05	19
March	130.67	120.00	25
April	135.00	121.02	15
May	139.58	127.11	26
June	140.00	131.53	21
July	144.00	135.01	5
August	140.00	120.00	53
September	139.10	131.00	15
October	140.00	133.00	24
November	145.00	133.40	15
December	155.34	143.17	34

7.2 Prior Sales

During the year ended December 31, 2010, 1,160,204 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $4.05. One-third of the options vest on each of January 1, 2011, 2012 and 2013.

During the year ended December 31, 2011, the Board approved the following grant of options:

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;
- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.68.

On March 14, 2012, 1,194,606 options were granted to senior executives of APUC and senior managers which allow for the purchase of common shares at a price of $6.22.

All options are issued at the market price of the underlying common share at the date of grant. In each case, one-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

During the year ended December 31, 2011, no options were exercised. As at December 31, 2011, APUC had 2,487,104 options issued and outstanding. As at December 31, 2011, 386,735 options are exercisable. No share options were exercised in 2011 or 2010.

	Number of shares	Weighted average exercise price	Weighted average remaining contractual term
Balance at January 1, 2011	1,160,204	$ 4.05	7.62
Granted	1,326,900	5.38	8.00
Balance at December 31, 2011	2,487,104	$ 4.76	6.96
Exercisable at December 31, 2011	386,735	$ 4.05	6.62

7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

The following securities of the Corporation are being held in escrow or subject to contractual restrictions on transfer as of the date of this AIF:

Description	Number of Securities held in escrow	Percentage of class
Subscription receipts	27,101,131(1)	100%
Common Shares	8,523,000(2)	5.8%

(1) Consists of the 12,000,000 subscription receipts issued pursuant to the Subscription Agreement (National Grid); 6,890,131 subscription receipts issued to Emera on July 5, 2011; and subscription receipts issued pursuant to the Subscription Agreement (Calpeco). These subscription receipts are being held by CIBC Mellon Trust Company as escrow agent. The Subscription Agreement (National Grid) will be released from escrow when the EnergyNorth and Granite State acquisitions are completed and the subscription receipts convert into APUC Common Shares (or if such acquisitions are terminated and the subscription receipts are cancelled). The 6,890,131 subscription receipts relate to an acquisition that the Corporation has determined not to proceed with, and such subscription receipts will be cancelled and released from escrow when a termination agreement relating to the subscription receipts is executed. The 8,211,000 subscription receipts will be released from escrow either (i) in two tranches, where 4,790,000 will be released when the Corporation completes the acquisition of Emera’s interest in the California Utility and the subscription receipts convert into APUC Common Shares and 3,421,000 will be released following the completion of the California Utility’s first rate case or (ii) if the acquisition of the California Utility is terminated.

(2) These shares were issued to Emera upon conversion of subscription receipts effective January 1, 2011. The shares are subject to restrictions on transfer until January 1, 2014, as set out in the Subscription Agreement dated April 22, 2009.

8. DIRECTORS AND OFFICERS

8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC, and information on their history with APCo. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 61	Mr. Ball is currently the Executive Vice President of Corpfinance International Limited, an investment banking boutique firm. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a Director of the Independent Power Association of British Columbia.	Director of APUC since October 27, 2009. Trustee of APCo since October 22, 2002	24,200

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
KENNETH MOORE Toronto, Ontario, Canada Age: 53	Mr. Moore is currently the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., another Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation and has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Chartered Director (“**Ch. Dir.**”).	Director of APUC since October 27, 2009. Trustee of APCo since December 18, 1998	18,000
GEORGE L. STEEVES Aurora, Ontario, Canada Age: 62	Mr. Steeves is the Principal of True North Energy, an energy consulting firm. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the president of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a Chairman, director and/or audit committee member of public and private companies, including APCo, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. He received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia.	Director of APUC since October 27, 2009. Trustee of APCo since September 8, 1997	17,241[1]
CHRISTOPHER HUSKILSON Wellington, Nova Scotia, Canada Age: 54	Mr. Huskilson is currently the President and Chief Executive Officer of Emera Incorporated, a North American energy and services company. Since 1980, Mr. Huskilson has held a number of positions within Nova Scotia Power Inc, and is currently a director of Emera Incorporated, Nova Scotia Power Inc. and chairman of Bangor Hydro-Electric Company.	Director of APUC since October 27, 2009. Trustee of APCo since July 27, 2009	nil [2]
DAVID BRONICHESKI Oakville, Ontario, Canada Age: 52	Mr. Bronicheski is the Chief Financial Officer (“CFO”) of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA. He is also a Chartered Accountant.	Officer of APUC since October 27, 2009. Officer of APCo since September 17 2007[3] [4]	40,000[7][8][9]

Name and Place of Residence	Principal Occupation	Served as Director or Officer of APUC from	Number of Common Shares
CHRISTOPHER K. JARRATT(5) (6) Oakville, Ontario, Canada Age: 53	Mr. Jarratt is currently the Vice Chairman of APUC. Mr. Jarratt is a founder and principal of Algonquin Power Corporation Inc. ("APC"), a private independent power developer formed in 1988. Mr. Jarratt has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir.. He holds a Professional Engineer designation and an Honours Bachelor of Science degree from the University of Guelph	Director of APUC since June 23, 2010.	407,444(7)(8)(9)
IAN E. ROBERTSON(5) (6) Oakville, Ontario, Canada Age: 52	Mr. Robertson is currently the President and Chief Executive Officer of APUC. Mr. Robertson is a founder and principal of APC. Mr. Robertson has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir.. He received a Bachelor of Engineering from the University of Waterloo and holds the Professional Engineering designation along with a Master of Business Administration degree from York University and a Chartered Financial Analyst designation	Director of APUC since June 23, 2010.	423,546(7)(8)(9)
LINDA BEAIRSTO Ontario,Canada Age: 51	Ms. Beairsto has been general counsel for APUC since June 2011 and also holds the role of Corporate Secretary of APUC. Prior to her position with APUC, she was in-house legal counsel for a large Bay Street law firm and several multinational companies. Ms. Beairsto attended law at the University of New Brunswick and was called to the bar in Ontario in1990.	Officer of APUC since June 6, 2011	Nil(9) (10)

Notes:

(1) Mr. Steeves' directly owns 14,327 Common Shares and Mr. Steeves' spouse owns 2,914 Common Shares. Mr. Steeves exercises control and direction over the Common Shares owned by his spouse.

(2) Mr. Huskilson does not own any Common Shares.

(3) Mr. Bronicheski became an officer of APCo on September 17, 2007.

(4) Prior to becoming an officer of APCo in September 2007, Mr. Bronicheski was the CFO of Amtelecom Income Fund from July 2003 to July 2007.

(5) Messrs. Jarratt and Robertson, together with others, collectively own all of the issued and outstanding shares of APMI.

(6) As consideration for payment of APUC's acquisition of APMI's interest in the management agreement, Mr. Robertson and Mr. Jarratt following shareholder approval at the Meeting each received 295,045 Common Shares.

(7) Messrs. Jarratt, Robertson, and Bronicheski hold 436,224, 494,388, and 229,593 stock options respectively, granted on August 12, 2010. The stock options allow for the purchase of Common Shares at a price of $4.05. One-third of the stock options vests on each of January 1, 2011, 2012 and 2013. Stock options may be exercised up to eight years following the date of grant.

(8) Messrs. Jarratt, Robertson, and Bronicheski hold 335,423, 380,146, and 176,538 stock options respectively, granted on March 11, 2011. The stock options allow for the purchase of Common Shares at a price of $5.23. One-third of the stock options vests on each of January 1, 2012, 2013 and 2014. Stock options may be exercised up to eight years following the date of grant.

(9) Ms. Beairsto and Messrs. Jarratt, Robertson, and Bronicheski hold 85,000, 267,963, 350,413, and 162,917 stock options respectively, granted on March 14, 2012. The stock options allow for the purchase of Common Shares at a price of $6.22. One-third of the stock options vests on each of January 1, 2013, 2014, and 2015. Stock options may be exercised up to eight years following the date of grant.

(10) Ms. Beairsto holds 90,909 stock options granted on July 28, 2011, that allow for the purchase of Common Shares at a price of $5.74. One-third of the stock options vests on January 1, 2011, 2012, and 2013. Stock options may be exercised up to eight years following the date of grant.

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his successor is elected in accordance with the by-laws of APUC (the "**By-Laws"**).

As of March 30, 2011, approximately 870,990 Common Shares representing 0.59% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by Senior Executives and approximately 930, 431 Common Shares representing 0.63% of the issued and outstanding Common Shares are beneficially owned, directly or indirectly, by the directors and executive officers of the Corporation.

8.2 Audit Committee

Under the By-Laws, the directors may appoint from their number committees to effect the administration of the director's duties. The directors have established an Audit Committee comprised of three of the four independent directors of APUC, Mr. Ball (Chairman), Mr. Moore and Mr. Steeves, all of whom are independent and financially literate for purposes of National Instrument 52-110, *Audit Committees*. The Audit Committee is responsible for reviewing significant accounting, reporting and internal control matters, reviewing all published quarterly and annual financial statements and recommending their approval to the Directors and assessing the performance of APUC's auditors.

(a) Audit Committee Charter

The charter for APUC's audit committee (the "**Audit Committee**") is attached as Schedule E to this AIF.

(b) Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as Directors of APUC, of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee.

Mr. Ball has extensive financial experience, with over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Moore has extensive financial experience and is the Managing Partner of NewPoint Capital Partners Inc., a boutique financial advisory firm focused on mergers and acquisitions. He was formerly a Vice-President at a Canadian Chartered Bank. Mr. Moore holds a Chartered Financial Analyst and a Chartered Director designation.

Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University. Mr. Steeves is the former president of Cumming Cockburn Limited and has extensive financial experience in acting as a Chairman, director and/or audit committee member of public and private companies, including APCo, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia.

(c) Pre-Approval Policies and Procedures

All non-audit services proposed to be provided by APUC's auditors must be approved by the Directors prior to the auditors providing such services.

For the financial year ended December 31, 2011 and December 31, 2010, KPMG LLP charged the following fees to APUC:

Services	2011 Fees ($)	2010 Fees ($)
Audit Fees[1]	1,330,000	913,000
Audit-Related Fees[2]	278,000	110,000
Tax Fees[3]	907,850	885,000
All Other Fees	Nil	Nil

NOTES:

(1) For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements. The 2011 fees include additional costs related to APCo private placement and APUC equity offering.

(2) For assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and not reported under Audit Fees, including accounting advice and French translation services. Fees related to financial statement audits of subsidiary companies and other regulatory filing requirements in 2010 of $265,000 were reclassified to Audit Fees for comparative purposes.

(3) For tax compliance, advice and planning services.

8.3 Corporate Governance and Compensation Committees

The directors have also established a Corporate Governance Committee ("**CGC**") comprised of three of the independent directors of APUC, Mr. Steeves (Chair), Mr. Huskilson and Mr. Moore. The CGC includes two members of management by invitation, Mr. Robertson and Mr. Bronicheski. The mandate of the CGC includes the director nominating and evaluation process. The CGC is responsible for reviewing APUC's corporate governance practices. The CGC will also consider and make recommendations to the board from time to time regarding the effectiveness of the Directors and whether an increase to the number of directors is warranted.

The directors have also put in place a Compensation Committee ("**CC**"), comprised of Directors Mr. Huskilson (Chair) and Mr. Ball. The CC includes two members of management by invitation, Mr. Robertson and Mr. Jarratt.

The CC shall exercise the responsibilities and duties set forth below, including but not limited to:

- Selecting and appointing the CEO of the Corporation;
- Approving executive compensation plan (including philosophy and guidelines);

- Recommending to the Board compensation arrangements for the CEO and reviewing and approving compensation arrangements for Designated Employees and Directors;
- Reviewing and approving management succession plans; and
- Approving the grant of stock options.

8.4 Bankruptcies

Mr. Moore was a director of Telephoto Technologies Inc., a private sports and entertainment media. Telephoto Technologies Inc. was placed into receivership in August, 2010 by Venturelink Funds. Mr. Moore resigned from the board of directors of Telephoto Technologies Inc. in April, 2010.

8.5 Potential Material Conflicts of Interest

Other than as set out below or disclosed elsewhere in this AIF and APUC's financial statements and management's discussion and analysis for the fiscal year ended December 31, 2011, APUC is not aware of any existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary. Mr. Huskilson is a director of APUC but also the President and CEO of Emera, and Emera is a shareholder of APUC, is a co-owner of Calpeco with Liberty Utilities (West), has entered into agreement to acquire 12 million Common Shares through subscription receipts subject to certain trigger events, and is also in a strategic relationship with APUC. Mr. Huskilson does not vote in Board meetings on matters involving APUC's relationship with Emera nor on matters involving a potential conflict between APUC and Emera.

9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2011 are as follows:

(a) Trafalgar

As reported in previous public filings of APUC, APCo owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar was previously awarded a U.S. $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was reached in 2004 between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal fees, third party costs and other liabilities with the proceeds from the lawsuits being shared after reimbursement of legal fees, third party costs and other liabilities. The Board has determined that any proceeds from the lawsuit will be shared between APMI and APUC proportionally to the quantum of such costs funded by each party. The Second Circuit Court of Appeals dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

(b) Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Québec AG filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation ("**Seaway Management**") under its water lease with Seaway Management. The water lease contains a "hold harmless" clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the "**Federal Authorities**") into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $4.8 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, APCo accrued $1.0 million of water lease owed to Québec AG for 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $0.3 million were also recorded in 2011.

9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2011, there have been:

(a) no penalties or sanctions imposed against APUC by a court relating to securities legislation or by a securities regulatory authority;

(b) no other penalties or sanctions imposed by a court or regulatory body against APUC that would likely be considered important to a reasonable investor in making an investment decision; or

(c) no settlement agreements that APUC has entered into with a court relating to securities legislation or with a securities regulatory authority.

10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this AIF, and as disclosed in APUC's annual financial statements and management's discussion and analysis as at and for the periods ended

December 31, 2011, 2010, and 2009, management has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC.

11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Trust Units is CIBC Mellon Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, Halifax and Winnipeg.

12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of APUC and its subsidiaries, the contracts described below are the only contracts entered into by APUC or its subsidiaries during 2011 (or prior to 2010 in the case of contracts that are still in effect) that are material to APUC. It is worthy of note that Transfer Agreements dated December 21, 2009 with each of the principals of APMI that transferred their interests in the Management Agreement (as discussed in the Management Information Circular dated June 1, 2010) were approved in 2010 by the Shareholders at the Meeting as well as the TSX. The previously disclosed material contracts with Management have all been terminated as they pertain to APUC. These are the Management Agreement, the Operations Supervisory Agreement, the Administration Agreement, the Governance Agreement and the Direct Operations Agreements, all as defined in the AIF of APUC dated March 31, 2011.

(a) **Cornwall Solar Acquisition**: On November 24, 2011 APCo entered into a share purchase agreement with EffiSolar, to acquire all of the issued and outstanding shares of Cornwall Solar Inc. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012.

(b) **U.S. Wind Farm Portfolio**: Amended and Restated 51% Membership Interest Purchase and Sale Agreement ("**MIPA**") entered into as of December 30, 2011, as amended and restated as of March 8, 2012, by and among APFA (the "**Wind Farm Buyer**"), and Gamesa Energy USA, LLC, a Delaware limited liability company (the "**Wind Farm Seller**"). Termination of 49% MIPA by that certain letter to APFA c/o APUC dated March 8, 2012, sent by the Wind Farm Seller and as acknowledged and agreed to by the Wind Farm Buyer. 51% MIPA Guarantee dated as of March 8, 2012 made by APUC in favor of the Wind Farm Seller. 51% MIPA Guarantee dated as of March 8, 2012 made by Gamesa in favor of APFA. Indemnification Agreement entered into as of March 8, 2012, by and among the Wind Farm Seller and Gamesa, Wind Portfolio Sponsorco, LLC and APFA. Indemnification Agreement dated March 8, 2012, by and among the various parties to the transaction, including Gamesa and APFA.

(c) **Midwest Utility Transaction Documents:** An Asset Purchase Agreement entered into on May 12, 2011 between Atmos Energy Corporation, as Seller, and Liberty Midstates, as Buyer.

(d) **APCo debentures:** APCo Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of senior unsecured debentures from time to time. A First Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of $135,000,000 5.50% senior unsecured debentures due July 25, 2018. The notes are interest only until maturity. The funds were used to repay the Airsource Senior Debt and to reduce outstanding indebtedness under the APCo Facility.

(e) **Emera Strategic Agreement:** Strategic Agreement between APUC and Emera dated April 29, 2011 which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

(f) **LU credit agreement:** Credit agreement dated January 18, 2012 between Liberty Utilities as Borrower and JP Morgan Chase Bank N.A. as Lender and Administrative Agent. The Lender has agreed to provide a three year, unsecured operating line of U.S. $80 million to Liberty Utilities to support the working capital and operating needs of Liberty Utilities and its subsidiaries.

(g) **Chaplin:** On February 28, 2012 APCo announced that it was awarded and had signed a 177 megawatt power purchase contract with SaskPower.

(i) **St Leon II:** On July 18, 2011 APUC executed of a 25-year PPA with Manitoba Hydro in respect of a 16.5MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba. On the same day the St. Leon II Energy LP executed a Turbine Supply Agreement and a Service and Maintenance Agreement with Vestas Canadian Wind Technology, Inc. for the procurement and operation of ten 1.65MW wind turbines.

(j) **National Grid Transaction Documents:** Two Stock Purchase Agreements each entered into on December 8, 2010 and amended and restated January 21, 2011 between National Grid, as Seller, and Liberty Energy, as Buyer. One agreement is for the purchase of all issued and outstanding shares of Granite State, and the other is for all the issued and outstanding shares of EnergyNorth. The interests of Buyer in the agreements have been transferred to Liberty Energy NH. The closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in the second quarter of 2012.

(k) **Subscription Agreement (National Grid)**: Subscription agreement dated as of March 25, 2011 for the private placement of 12,000,000 subscription receipts from APUC to Emera at a price of $5.00 per subscription receipt. The proceeds of this subscription receipt transaction will be used to fund the National Grid acquisitions. See "*General Development of the Business – Significant Acquisitions – 2011 – New Hampshire Utility Acquisition* ".

(l) **Subscription Agreement (First Wind):** Subscription agreement dated as of July 5, 2011 for the private placement of 6,890,131 subscription receipts from APUC to Emera at a price of $5.37 per subscription receipt. Payment for these subscription receipts was satisfied by delivery by Emera of a non-interest bearing promissory note in the amount of $37,000,000. Upon the satisfaction of conditions precedent to the closing of the investment in First Wind Holdings, LLC's ("**First Wind**") wind energy facilities portfolio in the North East United States (other than payment of the purchase price), including the receipt of all necessary regulatory approvals, the promissory note will become due and payable and the rights evidenced by the subscription receipts will be deemed to have been satisfied by the delivery of Common Shares from APUC on a one-for-one basis, subject to customary anti-dilution adjustments. As APUC announced on January 27, 2012 that it will no longer proceed with the First Wind investment, these subscription receipts will be cancelled and will not convert into Common Shares of APUC.

13. INTERESTS OF EXPERTS

KPMG LLP is the external auditor of the Corporation and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Ontario.

14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and management discussion and analysis for the year ended December 31, 2011.

SCHEDULE A

Renewable—Hydroelectric and Wind Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates(1)	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Renewable Ontario Facilities					
Facility: Long Sault Rapids Facility (Hydroelectric) Owner: Algonquin Power (Long Sault) Partnership and N-R Power Partnership	18,000	Abitibi River near Cochrane, Ontario	**Electricity Purchaser:** OEFC **Rates:** $0.09634/kW-hr (average estimate)	111,600	2047
Facility: Hurdman Dam Facility (Hydroelectric) Owner: APFC	570	Mattawa River near Mattawa, Ontario	**Electricity Purchaser:** Ontario Power Authority Rates: $0.07334/kW-hr Paid on Hydroelectric Contract Incentive rate	3,150	2031
Facility: Burgess Dam Facility (Hydroelectric) Owner: APFC	140	Muskoka River near Bala, Ontario	**Electricity Purchaser:** Hydro One Inc Rates: Paid on Hourly Spot Market Price	0	month to month
Facility: Campbellford Facility (Hydroelectric) Owner: Campbellford LP	4,000	Trent River near Campbellford, Ontario	**Electricity Purchaser:** OEFC Rates: $0.04346/kW-hr (average estimate)	26,250	2019
Renewable Québec Facilities					
Facility: Saint-Alban Facility (Hydroelectric) Owner: SLI	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	37,650	2016
Facility: Glenford Facility (Hydroelectric) Owner: Glenford Partnership	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	24,000	2020
Facility: Rawdon Facility (Hydroelectric) Owner: APFC	2,500	Ouareau River near the Village of Rawdon, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	15,400	2014

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Côte Ste-Catherine Facility (Hydroelectric) Owner: Mont-Laurier Partnership	11,120	St. Lawrence River near the Town of Ste.-Catherine, Québec	**Electricity Purchaser:** Hydro-Québec Rates: Phase I Energy $0.04911/kW-hr Phase II Energy $0.06703/kW-hr Capacity $164.10/kW * Phase III Energy $0.06979/kW-hr Capacity $172.06/kW* * calculated over the average kilowatt output over the period December to March	Phase 1: 15,500 Phase II: 35,100 Phase III: 34,750	Phase 1: 2021 Phase II: 2018 Phase III:2021
Facility: Ste-Raphaël Facility (Hydroelectric) Owner: APFC	3,500	Rivière de Sud near Québec City, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	22,550	2014
Facility: Mont Laurier Facility (Hydroelectric) Owner: Mont-Laurier Partnership	2,725	Rivière-du-Lièvre in the Town of Mont Laurier, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.05907/kW-hr	21,250	2027
Facility: Rivière-du-Loup Facility (Hydroelectric) Owner: APFC	2,600	Rivière-du-Loup near the Town of Rivière-du-Loup, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	17,250	2015
Facility: Hydraska Facility (Hydroelectric) Owner: APT	2,250	Yamaska River near the Town of St.-Hyacinthe, Québec	**Electricity Purchaser:** Hydro-Québec Rates: Summer Energy $0.06591/kW-hr Winter Energy $0.12086/kW-hr	9,100	2014
Facility: Ste-Brigitte Facility (Hydroelectric) Owner: APFC	4,200	Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	12,750	2014
Facility: Belleterre Facility (Hydroelectric) Owner: APFC	2,200	Winneway River in the Municipality of Laforce, Québec	**Electricity Purchaser:** Hydro-Québec Rates: Summer Energy: $0.06532/kW-hr Winter Energy: $0.12046/kW-hr Capacity: $161.45/kilowatt (over the average kilowatt output over the period December to March)	11,250	2013

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Donnacona Facility (Hydroelectric) Owner: Donnacona Partnership	4,800	Jacques Cartier River near Donnacona, Québec	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	20,550	2022
Facility: St. Raphaël de Bellechasse Facility (Arthurville) (Hydroelectric) Owner: APT	650	Riviere du Sud downstream from Ste-Raphaël	**Electricity Purchaser:** Hydro-Québec Rates: $0.07837/kW-hr (Jan – Nov) $0.08072/kW-hr (Dec)	0[4]	2013
Renewable New York Facilities					
Facility: Ogdensburg Facility (Hydroelectric) Owner: Trafalgar[2]	3,675	Oswegatchie River near Ogdensburg, New York	**Electricity Purchaser:** National Grid Rates: US$0.04296/kW-hr (est)[3]	11,100	2016
Facility: Forestport Facility (Hydroelectric) Owner: Trafalgar[2]	3,300	Black River near Boonville, New York	**Electricity Purchaser:** National Grid Rates: US$0.04265/kW-hr (est) [3]	11,500	2016
Facility: Herkimer Facility (Hydroelectric) Owner: Trafalgar[2]	1,680	West Canada Creek near Herkimer, New York	**Electricity Purchaser:** National Grid Rates: No target rate as the site is expected to be offline	0[4]	2016
Facility: Christine Falls Facility (Hydroelectric) Owner: Christine Falls Corporation[2]	850	Sacandaga River near Clifton, New York	**Electricity Purchaser:** National Grid Rates: US $0.04145/kW-hr (est) [3]	3,300	2028
Facility: Cranberry Lake (Hydroelectric) Owner: Trafalgar[2]	500	Oswegatchie River near Clifton, New York	**Electricity Purchaser:** National Grid Rates: US$0.04297/kW-hr (est) [3]	1,800	2016
Facility: Kayuta Lake Facility (Hydroelectric) Owner: Trafalgar[2]	400	Black River near Boonville, New York	**Electricity Purchaser:** National Grid Rates: US$0.00822/kW-hr (est)	1,800	2028
Facility: Adams Facility (Hydroelectric) Owner: Trafalgar [2]	350	Sandy Creek near Adams, New York	**Electricity Purchaser:** National Grid Rates: No target rate as the site is expected to be offline	0[4]	2028
Facility: Kings Falls Facility (Hydroelectric) Owner: Tug Hill Energy, Inc.[5]	1,750	Deer River near Copenhagen, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012[6]	0[6]	2016

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Otter Creek Facility (Hydroelectric) Owner: Tug Hill Energy, Inc.[5]	530	Otter Creek in Craig, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012 [7]	0[6]	2016
Facility: Phoenix Facility (Hydroelectric) Owner: Oswego Hydro Partners L.P.[5]	3,500	Oswego River in Phoenix, New York	**Electricity Purchaser:** National Grid Rates: US$0.09205/kW-hr Flat Rate	11,250	2026
Facility: Beaver Falls Facility (Hydroelectric) Owner: Algonquin Power (Beaver Falls) LLC	2,500	Beaver River in Beaver Falls, New York	**Electricity Purchaser:** National Grid Rates: US$0.02852/kW-hr (est)	15,400	2019
Facility: Burt Dam Facility (Hydroelectric) Owner: Burt Dam Partnership	600	18 Mile Creek near Newfane, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012 [6]	0[6]	2016
Facility: Hollow Dam Facility (Hydroelectric) Owner: Hollow Dam Partnership	900	Oswegatchie River near Gouverneur, New York	**Electricity Purchaser:** National Grid Rates: No estimate complete for 2012 [6]	0[6]	2016
New England Facilities					
Facility: Greggs Falls Facility (Hydroelectric) Owner: Greggs Falls Partnership	3,500	Piscataquog River near the Town of Goffstown, New Hampshire	**Electricity Purchaser:** Public Service Company of New Hampshire ("PSNH") Rates: US$0.05407/kW-hr (est) [5]	10,450	60 day written notice
Facility: Pembroke Facility (Hydroelectric) Owner: Pembroke Hydro Associates Limited Partnership	2,600	Suncook River near the Town of Pembroke, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05461/kW-hr (est) [5]	9,750	60 day written notice
Facility: Clement Facility (Hydroelectric) Owner: Clement Dam Hydroelectric LLC	2,400	Winnipisaukee River near the Town of Tilton, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05551/kW-hr (est) [5]	10,700	60 day written notice
Facility: Franklin Facility (Hydroelectric) Owner: Franklin Power LLC	River Bend 1,600 Steven's Mill 200	Winnipesaukee River near the Town of Franklin, New Hampshire	**Electricity Purchaser:** PSNH Rates: River Bend US$0.05291/kW-hr (est) [5] Steven's Mill US$0.05609/kW-hr (est) [5]	River Bend 6,800 Steven's Mill 950	60 day written notice – both sites

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[1]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Lochmere Facility (Hydroelectric) Owner: HDI Partnership	1,200	Winnipesaukee River near Lochmere, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05560/kW-hr (est) [5]	4,150	60 day written notice
Facility: Lakeport Facility (Hydroelectric) Owner: Lakeport Corporation	600	Winnipesaukee River near Laconia, New Hampshire	**Electricity Purchaser:** PSNH Rates: US$0.05530/kW-hr (est) [5]	2,450	60 day written notice
Facility: Mine Falls Facility (Hydroelectric) Owner: Mine Falls Limited Partnership	3,000	Nashua River near the City of Nashua, New Hampshire	**Electricity Purchaser:** PSNH Rates: US $0.05483/kW-hr (est)[5]	11,400	60 day written notice
Facility: Great Falls Facility (Hydroelectric) Owner: Great Falls Partnership	10,950	Passaic River near the City of Paterson, New Jersey	**Electricity Purchaser:** Public Service Electric and Gas Company Rates: US $0.05470/kW-hr (est)[5]	23,350	60 day written notice
Facility: Moretown Facility (Hydroelectric) Owner: Moretown Partnership	1,200	Mad River near Moretown, Vermont	**Electricity Purchaser:** Vermont Power Exchange, Inc. Rates: $0.10780/kW-hr (average estimate)	0[4]	2018
Renewable—Western Canada Facility **Facility:** Dickson Dam Facility (Hydroelectric) **Owner:** APOT	15,000	Innisfail, Alberta	**Electricity Purchaser:** AESO Rates: Market Rates Energy: $0.0620/kW-hr (estimate)	65,000	NA
Renewable—Maritime Facilities **Facility:** Tinker Facility (Hydroelectric) Owner: APT	33,500	Perth-Andover, New Brunswick	**Electricity Purchaser:** AES Town of Perth-Andover **Rates:** AES ~ U.S. $0.046/kWhr Town of Perth Andover: ~ CDN $.085/kWhr (including transmission charges)	120,000	Perth-Andover Contract through 2021 AES contract through 2013
Facility: Caribou Facility (Hydroelectric) **Owner:** Maine Gen Co.	900	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Energy – ~U.S. $0.046/kWhr	5,300	n/a
Facility: Squa Pan Facility (Hydroelectric) Owner: Maine Gen Co.	1,400	Squa Pan Lake, near Caribou Maine	**Electricity Purchaser:** AES **Rates:** Energy – ~U.S. $0.046/kWhr	850	n/a

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates[(1)]	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA
Facility: Rattle Brook Facility (Hydroelectric) Owner: Rattlebrook Partnership	4,000	Rattle Brook near Jackson's Arm, Newfoundland	**Electricity Purchaser:** Newfoundland and Labrador Hydro Rates: Summer $0.07148/kW-hr Winter $0.09693/kW-hr	15,950	2024
Renewable—Solar Facility					
Facility: Cornwall Solar (Solar)	10,000	Cornwall, Ontario	**Electricity Purchaser:** (Under Development - OPA)	13,400	n/a
Renewable—Wind Facilities					
Facility: Chaplin Wind (Wind)	177,000	Chaplin, Saskatchewan	**Electricity Purchaser:** (Under Development - SaskPower)	247,000	n/a
Facility: St. Leon Facility (Wind) Owner: St. Leon LP	104,000	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro	372,000	2025 + one 5 year extension
Facility: Amherst Island (Wind)	75,000	Stella, Ontario	**Electricity Purchaser:** (Under Development - OPA)	247,000	n/a
Facility: Red Lily (Wind) Owner: Concord	26,400	Saskatchewan	**Electricity Purchaser:** SaskPower	88,000	2036
Facility: Morse (Wind)	25,000	Morse, Saskatchewan	**Electricity Purchaser:** (Under Development - SaskPower)	93,000	n/a
Facility: Saint-Damase (Wind)	24,000	Saint-Damase, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	86,000	n/a
Facility: Val-Éo (Wind)	24,000	Saint-Gédéon, Québec	**Electricity Purchaser:** (Under Development – Hydro-Quebec)	66,000	n/a
Facility: St. Leon II Facility (Wind)	16,500	St. Leon, Manitoba	**Electricity Purchaser:** Manitoba Hydro	58,000	2037

Notes:

(1) 2012 PPA rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable PPAs. Long-term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project.

(2) APC provides Trafalgar with certain operational services in respect of the Trafalgar Facilities.

(3) These rates reflect the estimated Avoided Costs of National Grid.

(4) Scheduled to be offline for repairs in 2012. No decision has been made as to the timing of repairing these Facilities.

(5) PSNH purchases the energy produced by these generating stations at the ISO-NE. market rates. These agreements are cancellable on 60 days written notice.

(6) This facility no longer fits APUC's preferred asset profile and is no longer considered strategic to APUC. As a result, APUC's interest in these facilities is expected to be sold in 2012.

SCHEDULE B

Thermal—Biomass, Cogeneration, Steam, Diesel and Energy From Waste Facilities

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Year of Expiry of Lease
Thermal - Biomass Facility						
Facility: Valley Power Facility (Biomass) Owner: Valley Power L.P.	12,000	Drayton Valley, Alberta	**Electricity Purchaser:** TransAlta Utilities Corporation Rates: Energy: $0.0709/kW-hr	0[1]	2014	Owned
Thermal—Cogeneration Facilities						
Facility: Sanger Facility (Cogeneration) Owner: Algonquin Power Sanger LLC	56,000	Sanger, California	**Electricity Purchaser:** PG&E **Rates:** US$ 0. 045/ kW-hr (estimated average)* * subject to gas price indexing Capacity – Approximately $298,000 January-April &November-December Approximately $1,093,000 May-October	98,000	2021	Owned
Facility: Windsor Locks Facility (Cogeneration) Owner: Algonquin Power Windsor Locks LLC	56,000	Windsor Locks, Connecticut	**Electricity Purchaser:** ISO New England Ahlstrom **Rates:** ISO New England-Market Rates , included hourly energy, forward capacity and forward reserve payments Mill/NGC - US$0. 049/kW-hr* Capacity $203,000** Steam - DNM/NGC - US$7.26/1000lbs* Capacity $127,000 * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are CPI indexed. Capacity Market and Spot Market – market prices	176,000 87,000	Merchant 2018	2018
Facility: Brampton Cogeneration Inc. (Cogeneration) Owner: APOT	N/A	Brampton, Ontario	**Electricity Purchaser:** N/A Rates: Steam - Normapac $8.45/1000lbs* Capacity $103,600** * Estimated average rate, includes variable component based on natural gas prices. **Estimated average monthly rate, charges are partially CPI indexed.	604 million lbs of steam	2024	N/A
Facility: EFW Facility (Energy from Waste) Owner: Algonquin Power Energy from Waste Inc.	10,100	Brampton, Ontario	**Electricity Purchaser:** OEFC Rates: $0.060/kW-hr (average estimated rate) Tipping - Peel – $91/tonne up to 127,900 tonnes, $66 tonnes thereafter Waste rates subject to monthly CPI indexing	7,450	2012	Owned

Generating Facility/Owner	Generating Capacity (kilowatts)	Location	Electricity Purchaser/ 2012 Power Purchase Rates	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of PPA	Year of Expiry of Lease
Thermal – Diesel Facilities						
Facility: Tinker Facility (Diesel) Owner: Tinker Gen Co.	1,000	Perth-Andover, New Brunswick	**Electricity Purchaser:** Not Under Contract **Rates:** Capacity only	0	NA	Owned
Facility: Caribou Facility (Diesel) Owner: Maine Gen Co.	7,000	Caribou, Maine	**Electricity Purchaser:** AES **Rates:** Capacity only	0	NA	Owned
Facility: Flo's Inn Facility (Diesel) Owner: Maine Gen Co.	4,000	Caribou, Maine	**Electricity Purchaser:** Not Under Contract **Rates:** **n/a**	0(2)	NA	Owned

Notes:

(1) This facility no longer fits APUC's preferred asset profile and is no longer considered strategic to APUC. As a result, APUC's interest in these facilities is expected to be sold in 2012.

(2) Available to provide capacity only. The thermal facilities located in Northern Maine and New Brunswick are not considered strategic to APUC. As a result APUC is taking steps to shutdown these facilities.

SCHEDULE C

Wastewater and Water Distribution Facilities

Utility	Owner	Location	Type of Utility	December 31, 2011 Connections	Rates
Black Mountain	Black Mountain Sewer Corporation	Carefree, Arizona	Wastewater	2,276	Residential US $65.24 (standard monthly rate)
Gold Canyon	Gold Canyon Sewer Company	Gold Canyon Arizona	Wastewater	7,423	Residential US $52.40 (standard monthly rate)
Bella Vista	Bella Vista Water Co., Inc.	Sierra Vista, Arizona	Water Distribution	9,012	Residential US $15.00 (Average monthly rate)
Tall Timbers	Tall Timbers Utility Company, Inc.	Tyler, Texas	Wastewater	2,185	Residential US $54.93 (standard monthly rate)
Woodmark	Woodmark Utilities, Inc.	Tyler, Texas	Wastewater	1,731	Residential US $47.76 (standard monthly rate)
Litchfield Park	Litchfield Park Service Company	Litchfield, Park, Arizona	Wastewater Water Distribution	18,891 16,564	Residential US $56.54 Commercial US $95.60 US $39.58 (Average residential rate)
Fox River	AWRI	Sheridan, Illinois	Wastewater Water Distribution	219 220	US $240.08 US $141.61
Timber Creek	AWRM	DeSoto, Missouri	Wastewater Water Distribution	20 25	US $16.00 min & $17.24/1000 gal. US $8.96 min. & US $5.96/1000 gal
Holiday Hills	AWRM	Branson, Missouri	Water Distribution	484	US $8.96 min. & US $5.96/1000 gal
Ozark Mountain	AWRM	Kimberling City, Missouri	Wastewater Water Distribution	241 256	US $16.00 min & $17.24/1000 gal. US $8.96 min. & $5.96/1000 gal
Holly Lake Ranch	AWRT	Hawkins, Texas	Wastewater Water Distribution	152 1,725	US $128.53 min & US $3.65/1000 gal. US $30.20 min. & $2.89/1000 gal
Big Eddy	AWRT	Flint, Texas	Wastewater Water Distribution	411 668	US $128.53 min & US $3.65/1000 gal. US $30.20 min. & $2.89/1000 gal
Piney Shores	AWRT	Conroe, Texas	Wastewater Water Distribution	269 273	US $128.53 min & US $3.65/1000 gal. US $39.81 min. & $1.30/1000 gal
Hill Country	AWRT	New Braunfels, Texas	Wastewater Water Distribution	379 225	US $128.53 min & US $3.65/1000 gal. US $39.81 min. & $1.30/1000 gal

Utility	Owner	Location	Type of Utility	December 31, 2011 Connections	Rates
Rio Rico	Rio Rico Utilities Inc.	Rio Rico, Arizona	Wastewater Water Distribution	2,207 6,429	US $45.88 (residential rates) US $10.98 min. & 0-3,000 gal – US $1.59/1,000 gal 3,001-9,000 gal – US $2.92/1,000 gal >9,000 gal – US $3.64/1,000 gal
Northern Sunrise	Northern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	352	US $15.00 min / Per 1000 / 0-4,000gal $1.45/ 4,000-10,000 gal $2.21 / >10,000 gal $2.72
Southern Sunrise	Southern Sunrise Water Company Inc.	Sierra Vista, Arizona	Water Distribution	866	US $15.00 min / Per 1000 / 0-4,000gal $1.45/ 4,000-10,000 gal $2.21 / >10,000 gal $2.72
Entrada Del Oro (1)	Entrada Del Oro Sewer Company	Gold Canyon , Arizona	Wastewater	337	US $70.00 (standard monthly rate)
Seaside Resort	AWRT	Galveston, Texas	Water Distribution Wastewater	156 156	US $166.68 US $165.45
Noel	AWRM	Noel, Missouri	Water Distribution	612	US $7.76 Consumption $1.80 per 1000 gallons
KMB	AWRM	Jefferson, Franklin and Cape Girardeau counties in Missouri	Wastewater Water Distribution	190 546	$27.60 Varies – Fixed Average US $17.33 Consumption Average US $3.57 per 1000 gal;
Total connections				**75,500**	

Notes:

(1) Liberty Water Co. currently holds a beneficial interest in the shares of the company pending regulatory approval of its acquisition.

SCHEDULE D

Electrical Distribution Facilities

Utility	Owner(1)	Location	Type of Utility	December 31, 2011 Connections	Rates
Calpeco	California Pacific Electric Company, LLC	Lake Tahoe, California	Electricity Distribution	47,000	Residential Rates – Monthly Charge $6.62 plus $0.10864/kwh for baseline usage; $0.13696 for excess usage. Commercial (Small) – Monthly Charge $12.22 plus $0.12882/kwh for baseline usage. Commercial - (Medium) – Monthly Charge $108.94 plus average rate of $0.09969/kwh for baseline usage. Commercial - (Large) – Monthly Charge $223.98 plus an average rate of $0.069376/kwh for baseline usage.

SCHEDULE E

ALGONQUIN POWER & UTILITIES CORP.

MANDATE OF THE AUDIT COMMITTEE

By appropriate resolution of the board of directors (the "**Board**") of Algonquin Power & Utilities Corp., the Audit Committee (the "**Committee**") has been established as a standing committee of the Board with the terms of reference set forth below. Unless the context requires otherwise, the term "Corporation" refers to Algonquin Power & Utilities Corp. and its subsidiaries.

1. PURPOSE

1.1 The Committee's purpose is to:

(a) assist the Board's oversight of:

(i) the integrity of the Corporation's financial statements, Management's Discussion and Analysis ("**MD&A**") and other financial reporting;

(ii) the Corporation's compliance with legal and regulatory requirements;

(iii) the external auditor's qualifications, independence and performance;

(iv) the performance of the Corporation's internal audit function and internal auditor;

(v) the communication among management of the Corporation and its subsidiary entities and the Corporation's Chief Executive Officer and its Chief Financial Officer (collectively, "**Management**"), the external auditor, the internal auditor and the Board;

(vi) the review and approval of any related party transactions; and

(vii) any other matters as defined by the Board;

(b) prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

2. COMMITTEE MEMBERSHIP

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

(a) be a director of the Corporation;

(b) not be an officer or employee of the Corporation or any of the Corporation's subsidiary entities or affiliates;

(c) be an unrelated director for the purposes of the Toronto Stock Exchange (the "**TSX**") Corporate Governance Policy; and

(d) satisfy the independence requirements applicable to members of audit committees under each of the rules of National Instrument 52 110 – Audit Committees of the Canadian Securities Administrators ("**NI 52 110**") and other applicable laws and regulations.

2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under the TSX Corporate Governance Policy, NI 52 110 and other applicable laws and regulations.

2.4 Annual Appointment of Members – The Committee and its Chair shall be appointed annually by the Board and each member of the Committee shall serve at the pleasure of the Board until he or she resigns, is removed or ceases to be a director.

3. COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly, a majority of the members of the Committee shall constitute a quorum and the Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings – As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Board approve, the annual audited financial statements of the Corporation or at which the Committee reviews the interim financial statements of the Corporation, and at such other times as the Committee deems appropriate, the Committee shall meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

(a) representatives of Management;

(b) the external auditor; and

(c) the internal audit personnel.

3.3 Attendance at Meetings – The external auditors are entitled to attend and be heard at each Committee meeting. In addition, the Committee may invite to a meeting any officers or employees of the Corporation, legal counsel, advisor and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities.

4. COMMITTEE AUTHORITY AND RESOURCES

4.1 Direct Channels of Communication – The Committee shall have direct channels of communication with the Corporation's internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Corporation such independent legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.

4.3 Funding – The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this Charter.

4.4 Investigations – The Committee shall have unrestricted access to the personnel and documents of the Corporation and the Corporation's subsidiary entities and shall be provided with the resources necessary to carry out its responsibilities.

5. REMUNERATION OF COMMITTEE MEMBERS

5.1 Director Fees Only – No member of the Committee may accept, directly or indirectly, fees from the Corporation or any of its subsidiary entities other than remuneration for acting as a director or member of the Committee or any other committee of the Board.

5.2 Other Payments – For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Corporation. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any of its subsidiaries, other than limited partners, non–managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

6. DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

6.1 Overview – The Committee's principal responsibility is one of oversight. Management is responsible for preparing the Corporation's financial statements and the external auditor is responsible for auditing those financial statements.

6.2 The Committee's specific duties and responsibilities are as follows:

(a) Financial and Related Information

(i) Annual Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's annual financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(ii) Interim Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's interim financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(iii) Prospectuses and Other Documents – The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Board as a whole.

(iv) Accounting Treatment – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Corporation's accounting principles and financial statement presentation, including, without limitation, the following:

(A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of Management's disclosures along with any significant proposed modifications by the auditors that were not included;

(B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management's judgments and accounting estimates and the external auditor's judgments about the quality of the Corporation's accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor's preferred accounting treatment or accounting policy is not selected, the reasons therefore should also be reported to the Committee;

(C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

(E) any significant changes in the Corporation's selection or application of accounting principles;

(F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and

(G) the adequacy of the Corporation's internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information – The Committee shall:

(A) review, and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Corporation containing audited, unaudited or forward-looking financial information in advance of its public release by the Corporation, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

(B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

(C) satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the Corporation's financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

(b) External Auditor

(i) Authority with Respect to External Auditor – As representative of the Corporation's shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation's shareholders for appointment as external auditor, whether at any time the incumbent external auditor should be removed from office, and the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan – The Committee shall approve, prior to the external auditor's audit, the external auditor's audit plan (including, without limitation, staffing), the scope of the external auditor's review and all related fees.

(iii) Independence – The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

(A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Corporation and the Committee shall actively engage in a dialogue with the external auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Board take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor's independence.

(B) In accordance with applicable laws and regulations, the Committee shall pre–approve any non–audit services (including, without limitation, fees therefore) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non–audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non audit services. The Chair may approve additional non audit services that arise between Committee meetings, provided that the Chair reports any such approvals to the Committee at the next scheduled meeting.

(C) The Committee shall establish a policy setting out the restrictions on the Corporation's subsidiary entities hiring partners, employees, former partners and former employees of the Corporation's external auditor or former external auditor.

(iv) Rotating of Auditor Partner – The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit – The Committee shall review with the external auditor:

(A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Corporation's response to that letter;

(B) any changes required in the planned scope of the internal audit; and

(C) the internal audit department's responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Corporation's auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by CAS 260 of the CICA Handbook – Assurance relating to the conduct of the audit.

(c) Internal Audit Function – Controls

(i) Regular Reporting – Internal audit personnel shall report regularly to the Committee.

(ii) Oversight of Internal Controls – The Committee shall oversee Management's design and implementation of and reporting on the Corporation's internal controls and review the adequacy and effectiveness of Management's financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems devisable in respect of the internal audit function.

(iii) Review of Audit Problems – The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management's responses thereto.

(iv) Review of Internal Audit Personnel – The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(d) Risk Assessment and Risk Management

(i) Risk Exposure – The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Corporation's major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) Investment Practices – The Committee shall review Management's plans and strategies around investment practices, banking performance and treasury risk management.

(iii) Compliance with Covenants – The Committee shall review Management's procedures to ensure compliance by the Corporation with its loan covenants and restrictions, if any.

(e) Legal Compliance

(i) On at least a quarterly basis, the Committee shall review with the Corporation's legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Corporation's financial position, operating results or financial statements and the Corporation's compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Board with respect to the Corporation's policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Board, promptly after becoming aware of any material non–compliance by the Corporation with applicable laws and regulations.

(f) Whistle Blowing – The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation's subsidiary entities of concerns regarding questionable accounting or auditing matters.

(g) Related Party Transactions – The Committee shall review and approve any transaction between the Corporation and a related party and any transaction involving the Corporation and another party in which the parties' relationship could enable the negotiation of terms on other than an independent, arms' length basis.

(h) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

(i) Liaison – The Committee shall review and ensure that appropriate liaison and co–operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

(j) Public Reports – The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

(k) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

7. REPORTING TO THE BOARD

7.1 Regular Reporting – If applicable, the Committee shall report to the Board following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

8. EVALUATION OF COMMITTEE PERFORMANCE

8.1 Performance Review – The Committee shall periodically assess its performance.

8.2 Amendments to Charter

(a) Review by Committee – On at least an annual basis, the Committee shall review and discuss the adequacy of this Charter and if applicable, recommend any proposed changes to the Board.

(b) Review by Board – The Board will review and reassess the adequacy of the Charter on an annual basis and at such other times, as it considers appropriate.

9. LEGISLATIVE AND REGULATORY CHANGES

9.1 Compliance – It is the Board' intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this Charter shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least annually to reflect such amendments.

10. CURRENCY OF CHARTER

10.1 Currency of Charter – This Charter was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 31, 2010.

SCHEDULE F

Caution concerning forward-looking statements

Certain statements included in this AIF contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. Forward-looking information is included throughout this Annual Information Form, including among other places, under the heading “General Development of the Business”, “Description of the Business” and “*Legal Proceedings and Regulatory Actions*”. These statements and information are forward-looking, and are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments, and other factors believed to be appropriate in the circumstances.

Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include those set out in this AIF under “Risk Factors. Readers are cautioned that such risks and uncertainties may cause APUC’s actual results to vary materially from those expressed in, or implied by, the forward-looking statements and information. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

SCHEDULE G

GLOSSARY OF TERMS

In this Annual Information Form, the following terms have the meanings set forth below, unless otherwise indicated.

"**3793257**" means 3793257 Canada Inc., a corporation incorporated under the CBCA. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**AAP LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**ADEQ**" means the Arizona Department of Environmental Quality. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater"*.

"**AES**" means Algonquin Energy Services Inc., a Delaware corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**AESO**" means the Alberta Electric System Operator. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**Agreement**" has the meaning ascribed thereto under "*General Development of the Business—Recent Developments – 2012 – Corporate – Business Associations with APMI and Senior Executives"*.

"**AirSource**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**AirSource Senior Debt**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2011"*.

"Algonquin" or the **"Fund"** means Algonquin Power Income Fund. See *"General Development of the Business – General – The Unit Exchange"*.

"**Algonquin Holdco**" means Algonquin Power Fund (America) Holdco Inc., a Delaware corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APA**" means Algonquin Power (America) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APC**" means Algonquin Power Corporation Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**APCo**" means Algonquin Power Co. See *"Corporate Structure – Name, Address and Incorporation"*.

"**APCo Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**APEFW**" means Algonquin Power Energy From Waste Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APFA**" means Algonquin Power Fund (America) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APFC**" means Algonquin Power Fund (Canada) Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APMI**" means Algonquin Power Management Inc. See *"General Development of the Business – Three Year History – Fiscal 2009"*.

"**APOT**" means Algonquin Power Operating Trust. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APT**" means Algonquin Power Trust. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**APUC**" or the **"Corporation"** means Algonquin Power & Utilities Corp including, for reporting purposes only, the direct or indirect subsidiaries of APUC and partnership interests held by APUC and its subsidiaries. See *"Corporate Structure – Name, Address and Incorporation"*.

"**APUC Businesses**" means the two businesses through which APUC primarily conducts its operations: independent power generation and utilities (water, gas and electric). See *"General Development of the Business – General—Business Strategy"*.

"**Atmos**" means ATMOS Energy Corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Audit Committee**" means APUC's audit committee. See *"Directors and Officers – Audit Committee – Audit Committee Charter"*.

"**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"AWPH" means American Wind Portfolio Holdings LLC. See *"General Development of the Business – Recent Developments – 2012"*.

"**BCI**" means Brampton Cogeneration Inc.

"**BCI Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Belle Rivière**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Board**" means the APUC Board of Directors.

"**By-Laws"** means the by-laws of APUC.

"**California Utility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**Calpeco**" means California Pacific Electric Company, LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Campbellford Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Campbellford LP**" means Algonquin Power (Campbellford) Limited Partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Canadian ERs**" means the updated Final Essential Requirements for Mandatory Reporting for use in Canadian Partner jurisdictions. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**Caribou Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**CBCA**" means the *Canada Business Corporations Act*.

"**CC**" means Compensation Committee. See *"Directors and Officers – Corporate Governance and Compensation Committees"*.

"**CDP**" means the Carbon Disclosure Project. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**CGC**" means Corporate Governance Committee. See *"Directors and Officers – Corporate Governance and Compensation Committees"*.

"**Change of Control**" means the acquisition of voting control or direction over 66 2/3% or more of the outstanding Common Shares by any person or group of persons acting jointly or in concert. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Chapais**" means Chapais Energie, Société en Commandité. See *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

"**Clarica**" means The Clarica Life Insurance Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**CL&P**" means the Connecticut Light and Power Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**Cochrane**" means Cochrane Power Corporation. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**COD**" means commercial operation dates. See *"General Development of the Business – Recent Developments – 2012"*.

"**Common Shares**" means a new class of common shares created pursuant to a certificate and articles of arrangement dated October 27, 2009. See *"Corporate Structure – Name, Address and Incorporation"*.

"**Corporation**" means APUC.

"**Corporation St-Laurent**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Court Street**" means Court Street Investments, Inc., a Massachusetts corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Co-Owners**" means Algonquin Power (Long Sault) Partnership and N-R Power Partnership as co-owners of the Long Sault Rapids Facility. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**CPUV**" means California Pacific Utilities Ventures, LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Current Market Price**" is defined in the Series 3 Trust Indenture to mean the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**DEP**" means the US Department of Energy.

"**Dickson Dam Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**ECAC**" means the Energy Cost Adjustment Clause. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution"*.

"**EffiSolar**" means EffiSolar Energy Corporation. See *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Cornwall Solar"*.

"**EFW Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Electricity Act**" means the *Electricity Act (New Brunswick)*. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**EnergyNorth**" means EnergyNorth Natural Gas Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Entrada**" means Entrada Del Oro Sewer Company, Inc. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Éoliennes**" means Corporation D'Investissements Éoliennes Algonquin Power. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**EPA**" means the Environmental Protection Agency.

"**EPA Rule**" means the final Mandatory Greenhouse Gas Reporting Rule. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**ERs**" means the Final Essential Requirements for Mandatory Reporting. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**ESA**" means energy services agreement. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**ESPP**" means employee share purchase plan.

"**EUA**" means the *Electric Utilities Act (Alberta)*. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**Event of Default**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Federal Authorities**" means, together, the Attorney General of Canada and Seaway Management. See *"Legal Proceedings and Regulatory Actions – Legal Proceedings—Côte Ste-Catherine Water Lease Dues"*.

"**FERC**" means the United States Federal Energy Regulatory Commission. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"**First Wind**" means First Wind Holdings, LLC. See *"Material Contracts"*.

"**FIT**" has the meaning ascribed thereto under *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Cornwall Solar"*.

"**Fleur de Lis LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**FPA**" means the U.S. Federal Power Act.

"**Gamesa**" means Gamesa Corporación Tecnológica, S.A. See *"General Development of the Business – Recent Developments – 2012"*.

"**gpd**" means gallons per day. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater"*.

"**Granite State**" means Granite State Electric Company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Green Power**" means electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"**HOEP**" means Hourly Ontario Energy Price.

"**ICC**" means Illinois Commerce Commission.

"**ISO-NE**" means Independent System Operator New England. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**ITC**" means investment tax credit.

"**IUB**" means Iowa Utilities Board.

"**Kineticor**" has the meaning ascribed thereto under *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development"*.

"**Kirkland**" means Kirkland Lake Power Corp. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**Liberty Energy**" means Liberty Energy Utilities Co. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Liberty Energy (NH)**" means Liberty Energy Utilities (New Hampshire) Corp., a Delaware corporation registered in New Hampshire. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Liberty Facility**" has the meaning ascribed thereto under *"General Development of the Business – Recent Developments—2012"*.

"**Liberty Midstates**" means Liberty Energy (Midstates) Corp., a Missouri corporation. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Liberty Utilities**" means Liberty Utilities Company. See *"Corporate Structure – Name, Address and Incorporation"*.

"**Liberty Water**" means Liberty Water Co., a Delaware company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Loyalist LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**LSR Royalty Interest**" means a royalty in the form of cash flows generated by the Long Sault Rapids Facility. See *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

"**LSR Subordinate Note**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments"*.

"**LU GP1**" means Liberty Utilities Finance GP 1, a special purpose financing company and a Delaware general partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**LU GP2**" means Liberty Utilities Finance GP 2, a special purpose financing company and a Delaware general partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Manitoba Hydro**" means the Manitoba Hydro-Electric Board.

"**Meeting**" means the annual general meeting held on June 23, 2010.

"**Midwest Gas Utilities**" means certain natural gas distribution utility assets located in Missouri, Iowa, and Illinois. See *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Midwest Gas Utility Acquisition"*.

"**Midwest Purchase Agreements**" means the share purchase agreements by and between Atmos and Liberty Midstates entered into on May 12, 2011. See *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Midwest Gas Utility Acquisition"*.

"**MIPA**" means Membership Interest Purchase and Sale Agreement. See *"Material Contracts"*.

"**Ministry**" means the Minister of Energy and Infrastructure. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development"*.

"**Mont-Laurier Partnership**" means Algonquin Power (Mont-Laurier) Limited Partnership. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**MPS**" means Maine Public Service Company.

"**MPSC**" means Missouri Public Service Commission.

"**MW**" means megawatt.

"**National Grid**" means National Grid USA. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**NB Power**" means New Brunswick Power Corporation.

"**NBSO**" means New Brunswick System Operator. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**NHPUC**" means New Hampshire Public Utilities Commission.

"**Northern Maine Gen Co.**" means Algonquin Northern Maine Gen Co., a Wisconsin company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Northland**" means Northland Power Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**NTP**" means Notice to Proceed. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Development"*.

"**OATT**" means open access transmission tariff. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"**OEB**" means the Ontario Energy Board.

"OEFC" means Ontario Electric Financial Corporation.

"**Offering**" means a public offering completed by APUC on October 27, 2011 of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**Off-peak**" means the hours other than On-peak hours. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**On-peak**" means between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**Parties**" has the meaning ascribed thereto under "*General Development of the Business—Recent Developments – 2012 – Corporate – Business Associations with APMI and Senior Executives"*.

"**Peel**" means the Regional Municipality of Peel, Ontario.

"**PG&E**" means Pacific Gas & Electric Company. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration"*.

"**Plan Shares**" has the meaning ascribed thereto under *"Dividends – Dividend Reinvestment Plan."*

"**Power Pool**" means the Power Pool of Alberta. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"**Power Sales Contracts**" has the meaning ascribed thereto under *"General Development of the Business – Recent Developments—2012"*.

"**PPAs**" means long term power purchase agreements. See *"General Development of the Business – General – Business Strategy"*.

"**Projects**" means the four wind power projects in the United States acquired by APCo from Gamesa. See *"General Development of the Business – Recent Developments—2012"*.

"**PTAM**" means the Post Test Year Adjustment Mechanism. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Liberty Utilities: Electrical Distribution"*.

"**Purchase Agreement**" means the asset purchase agreement by and between Sierra Pacific Power Company d/b/a NV Energy and Calpeco dated April 22, 2009 in relation to the California Utility. See *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**Purchase Agreements**" means the share purchase agreements by and between National Grid and Liberty Energy entered into on December 8, 2010 and amended and restated on January 11, 2011. See *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**Put Date**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Put Price**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**QFs**" means Qualifying Facilities. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"**QF Status**" means Qualifying Facility status. See *"Risk Factors – Regulatory Climate and Permitting Risks – APCo"*.

"**Québec AG**" means the Attorney General of Québec. See *"Risk Factors – Legal Proceedings—Côte Ste-Catherine Water Lease Dues"*.

"**PURPA**" means the Public Utilities Regulatory Policies Act. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"**Red Lily I**" means a 26.4 MW wind generation facility in southeastern Saskatchewan. *"General Development of the Business – Significant Acquisitions and Investments – 2011 – Red Lily Wind Project"*.

"**Redemption Date**" means May 16, 2011. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**Region**" means the Region of Peel.

"**Reinvestment Plan**" has the meaning ascribed thereto under *"Dividends – Dividend Reinvestment Plan."*

"**RGGI**" means the Regional Greenhouse Gas Initiative. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**Rights Plan**" means APUC's Shareholders' Rights Plan adopted at the Meeting. See *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**RPPI**" means the Renewable Power Production Incentive program. See *"Description of the Business – General Description of the Regulatory Regimes in which the Business Operates – Power Generation Regulatory Regimes"*.

"**run of the river**" means a facility where there is a continuous discharge of water without storage and release of water. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Hydroelectric"*.

"S.E.N.C." has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Sanger LLC**" means Algonquin Power Sanger LLC, a California limited liability company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Seaway Management**" means The St. Lawrence Seaway Management Corporation. See *"Risk Factors – Legal Proceedings—Côte Ste-Catherine Water Lease Dues"*.

"**Senior Indebtedness**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Senior Indebtedness Postponement Provisions**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Senior Executives**" means two executives of APUC, Ian Robertson and Christopher Jarratt. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Senior Unsecured Debentures**" means $135 million in senior unsecured debentures issued by APCo on July 25, 2011 by way of private placement. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**Series 1A Debentures**" means the 7.50% convertible unsecured subordinated debentures issued by the Corporation in connection with the Unit Exchange on October 27, 2009 due 2014. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**Series 2A Debentures**" means APUC's 6.35% convertible unsecured subordinated debentures due November 30, 2016. See *"General Development of the Business – Recent Developments – 2012"*.

"**Series 2A Redemption Date**" means February 24, 2012. See *"General Development of the Business – Recent Developments – 2012"*.

"**Series 3 Conversion Price**" means $4.20 per Common Share. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Series 3 Debentures**" or the "**APUC Debentures**" means a public offering completed on December 2, 2009 of approximately $55 million principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017. See *"General Development of the Business – Three Year History – Fiscal 2009"*.

"**Series 3 Interest Payment Date**" means June 30 and December 31 in each year, commencing on June 30, 2010. See *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Series 3 Maturity Date**" has the meaning ascribed thereto under *"Description of Capital Structure – Convertible Debentures – Series 3 Debentures"*.

"**Series 3 Trust Indenture**" means the trust indenture dated as of December 2, 2009 between APUC and the Debenture Trustee. See *"Description of Capital Structure – Convertible Debentures"*.

"**Shareholders**" means registered holders of shares of APUC. See *"Dividends – Dividend Reinvestment Plan."*.

"**Squa Pan Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**St. Leon Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**St. Leon II**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**St. Leon II Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**St. Leon GP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**St. Leon LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**St. Leon Trust**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**St. Ulrich LP**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Strategic Agreement**" means the strategic investment agreement between APUC and Emera entered into on April 29, 2011. See *"General Development of the Business – Three Year History – Fiscal 2011"*.

"**Subscription Agreement**" has the meaning ascribed thereto under *"General Development of the Business – Significant Acquisitions and Investments – 2011 – California Utility Acquisition"*.

"**Subscription Agreement (Calpeco)**" has the meaning ascribed thereto under *"Description of Capital Structure – Common Shares"*.

"**Subscription Agreement (National Grid)**" has the meaning ascribed thereto under *"General Development of the Business – Significant Acquisitions and Investments – 2011 – New Hampshire Utility Acquisition"*

"**TCE**" means trichloroethylene. See *"Risk Factors – Operational Risk Management – Specific Environmental Risks"*.

"**TCEQ**" means the Texas Commission on Environmental Quality. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Utilities: Water and Wastewater"*.

"**Tinker Facility**" has the meaning ascribed thereto under *"General Development of the Business – Three Year History – Fiscal 2010"*.

"**Tinker Assets**" means the 36.8MW of electrical generating assets of Tinker Gen Co. in New Brunswick. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Tinker Gen Co.**" means Algonquin Tinker Gen Co., a Wisconsin company. See *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**TMO**" means Transition Management Office. See *"Risk Factors – Acquisitions and Divestitures – Transition Management Office"*.

"**Trafalgar**" has the meaning ascribed thereto under "*General Development of the Business—Recent Developments – 2012 – Corporate – Business Associations with APMI and Senior Executives – Trafalgar"*.

"**Treasury Purchase**" means newly issued Plan Shares purchased from APUC under the Reinvestment Plan. See *"Dividends – Dividend Reinvestment Plan"*.

"**Trust Units**" has the meaning ascribed thereto under *"Corporate Structure – Name, Address and Incorporation"*.

"**Unit Exchange**" has the meaning ascribed thereto under *"General Development of the Business – General – The Unit Exchange"*.

"**Valley Power Facility**" has the meaning ascribed thereto under *"Corporate Structure – Intercorporate Relationships – Subsidiaries"*.

"**Vestas**" means Vestas-Canadian Wind Technology, Inc. See *"Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power"*.

“**Water Services**” means Algonquin Water Services LLC. See *“Corporate Structure – Intercorporate Relationships – Subsidiaries”*.

“**Wind Farm Buyer**” means APFA. See *“Material Contracts”*.

“Wind Farm Seller” means Gamesa Energy USA, LLC, a Delaware limited liability company. See *“Material Contracts”*.

“**Windlectric**” means Windlectric Inc. See *“Corporate Structure – Intercorporate Relationships – Subsidiaries”*.

“**Windsor LLC**” means Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. See *“Corporate Structure – Intercorporate Relationships – Subsidiaries”*.

“**WPPI**” means Wind Power Production Incentive. See *“Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Renewable – Wind Power”*.

“**Yankee Gas**” means the Yankee Gas Service Company. See *“Description of the Business – Production Method, Principal Markets, Distribution Methods and Material Facilities – Power Generation: Thermal – Cogeneration”*.

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Section 3: EX-99.2 (AUDITED ANNUAL FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2011)

Exhibit 99.2

Consolidated Financial Statements of

Algonquin Power & Utilities Corp.

For the years ended December 31, 2011 and 2010

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2011.

March 21, 2012

"Ian Robertson"	*"David Bronicheski"*
Chief Executive Officer	Chief Financial Officer

KPMG LLP
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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheet as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with US generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2011 and December 31, 2010, and its consolidated results of operations and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

Algonquin Power & Utilities Corp.
Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72,887	$ 4,749
Short term investments (note 1(e))	833	3,674
Accounts receivable net of allowance for doubtful accounts of $255 and $380 (note 22)	44,394	25,875
Due from related parties (note 15)	2,275	718
Prepaid expenses	5,620	3,546
Supplies and consumables inventory	2,714	—
Current portion of notes receivable	482	1,172
Current portion of deferred tax asset (note 14)	13,022	14,015
Current portion of tax receivable (note 14)	133	—
Current regulatory assets (note 8)	2,458	—
	144,818	53,749
Long-term investments and notes receivable (note 5)	39,820	37,179
Deferred non-current income tax asset (note 14)	67,671	74,006
Property, plant and equipment (note 6)	945,956	761,740
Intangible assets (note 7)	55,269	73,886
Goodwill	9,710	995
Restricted cash (note 1(f))	4,693	3,564
Deferred financing costs	8,503	5,991
Non-current regulatory assets (note 8)	2,571	2,484
Other assets	3,577	3,355
	$ 1,282,588	$ 1,016,949
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 8,382	$ 2,182
Accrued liabilities	47,102	29,534
Current regulatory liabilities	2,469	—
Due to related parties (note 15)	1,795	1,534
Dividends payable	9,566	5,719
Current portion of long-term liabilities (note 9)	1,624	70,490
Current portion of other long-term liabilities (note 11)	1,037	420
Current portion of advances in aid of construction (note 1(o))	604	591
Current portion of derivative instruments (note 22)	2,935	2,338
Current income tax liability (note 14)	407	200
Current portion of deferred credit	6,314	11,020
Deferred income tax liability (note 14)	723	514
	82,958	124,542
Long-term liabilities (note 9)	331,092	189,468
Convertible debentures (note 10)	122,297	181,760
Other long-term liabilities (note 11)	11,027	11,405
Advances in aid of construction (note 1(o))	74,547	54,524
Non-current regulatory liabilities (note 8)	19,184	—
Deferred non-current income tax liability (note 14)	53,231	79,442
Derivative instruments (note 22)	5,209	3,525
Deferred credits (note 14)	30,348	32,222
Equity (note 12):		
Shareholders' capital	975,263	795,329
Additional paid-in capital	1,525	1,612
Deficit	(366,080)	(357,035)
Accumulated other comprehensive loss	(96,510)	(99,845)
Total Equity attributable to shareholders of Algonquin Power and Utilities Corp.	514,198	340,061
Non-controlling interest (note 3(a))	38,497	—
Total Equity	552,695	340,061
Commitments and contingencies (note 18)		
Subsequent events (notes 3, 6, 7, 8, 9, 10 and 12)		
	$ 1,282,588	$ 1,016,949

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

	2011	2010
Revenue:		
Non-regulated energy sales	$ 134,232	$ 129,977
Regulated energy sales and distribution	77,368	—
Waste disposal fees	16,406	9,039
Regulated water reclamation and distribution	44,989	38,011
Other revenue (note 17)	3,643	3,331
	276,638	180,358
Expenses		
Operating	88,420	69,568
Regulated commodities purchased	46,508	—
Non-regulated fuel for generation	24,628	25,929
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Administrative expenses	17,534	14,886
Write down of long-lived assets (notes 6 and 7)	16,520	2,492
Gain on foreign exchange	(652)	(528)
	238,784	158,962
Operating income	37,854	21,396
Interest expense	30,441	24,839
Interest, dividend income and other income (notes 16)	(5,659)	(5,164)
Acquisition related costs	2,965	3,015
Loss on derivative financial instruments (note 22 (c))	5,844	1,103
	33,591	23,793
Earnings (loss) from operations before income taxes	4,263	(2,397)
Income tax expense (recovery) (note 14)		
Current	300	(69)
Deferred	(23,339)	(20,722)
	(23,039)	(20,791)
Net earnings	27,302	18,394
Net earnings attributable to non-controlling interests	3,921	444
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 23,381	$ 17,950
Basic net earnings per share (note 19)	$ 0.20	$ 0.19
Diluted net earnings per share (note 19)	$ 0.20	$ 0.19

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)

	2011	2010
Net Earnings	$27,302	$ 18,394
Other comprehensive income (loss), before tax:		
Foreign currency translation adjustment due to accounting change (note 1(t))	—	(37,605)
Increase in unfunded pension obligation (note 1(q))	(48)	—
Foreign currency translation adjustment	4,272	(13,528)
Other comprehensive income, before tax:	4,224	(51,133)
Income tax expense related to items of other comprehensive income	—	—
Other comprehensive income (loss), net of tax:	4,224	(51,133)
Comprehensive income (Loss)	31,526	(32,739)
Less: comprehensive income attributable to the non-controlling interest	4,810	(444)
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp	$26,716	$(33,183)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

	2011	2010
Cash provided by (used in):		
Operating Activities:		
Net earnings	$ 27,302	$ 18,394
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Other amortization	2,192	2,148
Gain on sale of assets	(357)	—
Deferred taxes	(23,339)	(20,722)
Unrealized loss (gain) on derivative financial instruments	2,324	(7,142)
Share-based compensation	769	108
Write down of long-lived assets	16,520	2,492
Unrealized foreign exchange gain	—	(414)
Changes in non-cash operating items (note 20)	(1,542)	(85)
	69,695	41,394
Financing Activities:		
Cash dividends (note 13)	(28,582)	(18,901)
Cash distributions to non-controlling interest	(523)	(444)
Issuance of common shares	118,846	—
Deferred financing costs	(3,642)	(1,194)
Increase in long-term liabilities	204,759	98,787
Decrease in long-term liabilities	(134,932)	(80,078)
Increase in advances in aid of construction	6,288	4,857
Decrease in other long-term liabilities	(297)	(342)
	161,917	2,685
Investing Activities:		
Decrease / (increase) in restricted cash	(1,036)	575
Decrease / (increase) in short-term investments	(833)	36,212
Increase in other assets	(2,438)	(90)
Distributions received in excess of equity income	3,839	882
Receipt of principal on notes receivable	1,172	410
Increase in non-controlling interest	1,351	—
Proceeds from liquidation of Highground assets	1,073	170
Increase in long-term investments and notes receivable	(6,900)	(14,759)
Proceeds from sale of property, plant and equipment	1,583	—
Additions to property, plant and equipment	(60,745)	(20,789)
Acquisitions of operating entities (note 3(a))	(100,058)	(44,397)
	(162,992)	(41,786)
Effect of exchange rate differences on cash	(482)	(126)
Increase in cash and cash equivalents	68,138	2,167
Cash and cash equivalents, beginning of the period	4,749	2,582
Cash and cash equivalents, end of the period	$ 72,887	$ 4,749
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 28,143	$ 21,562
Cash paid during the period for income taxes	$ 195	$ (285)
Non-cash transactions		
Property, plant and equipment acquisitions in accruals	$ 8,556	$ —

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.
Consolidated Statement of Equity
(thousands of Canadian dollars)

For the year ended December 31, 2011:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2010	$795,329	$ 1,612	$ (357,035)	$ (99,845)	$ —	$340,061
Dividends declared and distributions to non-controlling interests	—	—	(32,426)	—	(523)	(32,949)
Conversion and redemption of convertible debentures	59,973	(815)	—	—	—	59,158
Issuance of common shares	118,888	—	—	—	—	118,888
Stock compensation expense	—	728	—	—	—	728
Acquisition of Liberty Energy (California)	—	—	—	—	34,210	34,210
Amounts received in connection with Highground transaction (note 3 (h))	1,073	—	—	—	—	1,073
Net earnings			23,381		3,921	27,302
Other comprehensive income	—	—	—	3,335	889	4,224
Balance, December 31, 2011	$975,263	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$552,695

For the year ended December 31, 2010:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI (CTA)	Non-controlling interests	Total
Balance, December 31, 2009	$785,828	$ 1,487	$ (352,220)	$ (48,712)	$ —	$386,383
Dividends declared and distributions to non-controlling interests	—	—	(22,765)	—	(444)	(23,209)
Conversion and redemption of convertible debentures	4,568	17	—	—	—	4,585
Stock compensation expense	—	108	—	—	—	108
Amounts received in connection with Highground transaction (note 3 (h))	170	—	—	—	—	170
Issuance pursuant to management internalization	4,763	—	—	—	—	4,763
Net earnings			17,950		444	18,394
Other comprehensive loss	—	—		(51,133)	—	(51,133)
Balance, December 31, 2010	$795,329	$ 1,612	$ (357,035)	$ (99,845)	$ —	$340,061

Algonquin Power & Utilities Corp. (“APUC” or the “Company”) is an incorporated entity under the Canada Business Corporations Act. APUC’s principal activity is the ownership of power generation facilities and water, gas and energy utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements.

APUC’s power generation business unit conducts business under the name Algonquin Power Co. (“APCo”). APCo owns or has interests in renewable energy facilities and thermal energy facilities representing more than 450 MW of installed electrical generation capacity. APUC’s Utility Services business unit conducts business under the name of Liberty Utilities Co. (“Liberty Utilities”). Liberty Utilities businesses operate under two separately managed regions – Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco). Liberty Utilities (South) currently owns a portfolio of utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois. Liberty Utilities (West) currently owns a 50.001% interest in an electric distribution utility serving the Lake Tahoe region of California (the “California Utility”). APUC has announced an agreement to acquire, subject to regulatory approval, the remaining 49.999% interest in the California Utility (see note 3 (a)). Liberty Utilities has also announced an agreement to acquire, subject to regulatory approval, Granite State Electric Company, a New Hampshire electric distribution company, and EnergyNorth Natural Gas Inc., a regulated natural gas distribution utility (see note 3 (b)).

The regulated utility operating companies owned by Liberty Utilities are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (see note 8).

1. Significant accounting policies

(a) Basis of preparation:

The accompanying consolidated financial statements and accompanying notes have been prepared in accordance with U.S. generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required under Regulation S-X provided by the Securities and Exchange Commission ("SEC"). These are the Company's first U.S. GAAP annual consolidated financial statements.

The Company's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the audited annual financial statements for the year ended December 31, 2010. The accounting policies set out below have been consistently applied under U.S. GAAP to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

(b) Basis of consolidation:

The accompanying consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary. Intercompany transactions and balances have been eliminated.

(c) Accounting for rate regulated operations:

APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Management believes the regulatory assets recorded in these financial statements are probable of recovery either because the Utilities received prior Regulator approval or due to regulatory precedent set for similar circumstances. Included in Note 8, Regulatory Assets & Liabilities are details of regulatory assets and liabilities, and their current regulatory treatment.

Under ASC 980, an allowance for funds used during construction projects that are included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation to the extent permitted by the regulator. It represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction).

The electric utilities' and the water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and NARUC, respectively.

(d) Cash and cash equivalents:

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

1. Significant accounting policies (continued)

(e) Short term investments:

Short term investments, consist of money market instruments with maturities commencing from January 2012 and are recorded at current market value. Included in short term investments is an investment of $nil (U.S. $nil) which is denominated in U.S. dollars (December 31, 2010 - $3,674 (U.S. $3,694)).

(f) Restricted cash:

Restricted cash represent reserves and amounts set aside pursuant to requirements of various debt agreements. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the current receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(h) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant, and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and replacement cost.

(i) Property, plant and equipment:

Property, plant and equipment, consisting of renewable and thermal generation assets, electrical, water and wastewater distribution assets, equipment and land, are recorded at cost. The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for equity funds used during construction ("AFUDC") for regulated property. Plant and equipment under capital leases are stated at the present value of minimum lease payments.

AFUDC reflects the cost of debt or equity funds used to finance construction and only is capitalized as part of the cost of regulated utility plant where such treatment is permitted by the regulator. AFUDC amounts capitalized are included in rate base for establishing utility rates. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835. The interest capitalized that relates to debt reduces interest expense on the income statement. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the Statement of Operations.

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

(in thousands of Canadian dollars except as noted and amounts per share)

1. Significant accounting policies (continued)

(i) Property, plant and equipment (continued):

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method. The range of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2011	2010	2011	2010
Generation				
Renewable	3 – 60	3 – 60	31	31
Thermal	3 – 40	3 – 40	22	22
Distribution				
Electrical	15 – 75	N/A	52	N/A
Water & wastewater	5 – 50	5 – 50	25	25
Equipment	5 – 50	5 – 50	24	24

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment are charged to earnings as incurred.

(j) Intangibles:

The fair value of power sales contracts and energy sales contracts acquired in business combinations are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition for power sales contracts and 12 months for energy sales contracts.

Customer relationships acquired in business combinations are amortized on a straight-line basis over their estimated life of 40 years.

1. Significant accounting policies (continued)

(k) Goodwill:

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in rate-base and is not amortized.

In accordance with ASC Update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment" issued by the FASB in September 2011, the Company annually assesses qualitative factors to determine whether it is more likely than not that the fair value of goodwill is less than its carrying amount. If it is more likely than not that its fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(l) Impairment of long-lived assets:

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Assets Held and Used: Recoverability of assets held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

Assets Held for Sale: Recoverability of assets held for sale is measured by comparing the carrying amount of an asset to its fair value less the cost to sell. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value less estimated costs to sell.

(m) Variable interest entities:

The Company performs analysis to assess whether its operations and investments represent variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE, since the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company. Total generating assets and long-term debt of Long Sault amount to $46,160 (2010 -$47,757) and to $38,136 (2010 -$39,033), respectively. The financial performance of Long Sault reflected on the statement of operations includes non-regulated energy sales of $9,804 (2010 -$7,037), operating expenses and amortization of $3,001 (2010 -$2,572) and interest expense of $3,984 (2010 -$4,126).

1. Significant accounting policies (continued)

(n) Long-term investments and notes receivable:

Investments in which APUC has significant influence but not control or joint control are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the Consolidated Statement of Operations. All other equity investments where APUC does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and the carrying amounts are adjusted only for other-than-temporary declines in value and additional investments. Income is recorded when dividends are received.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are initially recorded at cost, which is generally face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity.

An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate. The Company does not accrue interest when a note is considered impaired. When ultimate collectability of the principal balance of the impaired note is in doubt, all cash receipts on impaired notes are applied to reduce the principal amount of such notes until the principal has been recovered and are recognized as interest income thereafter. Impairment losses are charged against the allowance and increases in the allowance are charged to bad debt expense. Notes are written off against the allowance when all possible means of collection have been exhausted and the potential for recovery is considered remote.

(o) Advances in aid of construction:

The Company has various agreements with real estate development companies conducting business within the Company's service territories (the "developers"), whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development. These amounts are recorded as Advances in Aid of Construction in other long-term liabilities. In many instances, developer advances are subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods ranging from 10 to 20 years. Generally, advances not refunded within the prescribed period are not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to cost of property, plant and equipment. In 2011, $1,107 (2010 - $nil) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Other long-term liabilities:

Other long-term liabilities include deferred water rights. Deferred water rights are related to a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment, which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

1. Significant accounting policies (continued)

(p) Other long-term liabilities (continued):

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Utilities' obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be credit worthy.

(q) Pension plan:

Liberty Utilities (West) has a defined benefit cash balance pension plan covering substantially all its employees, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The plan interest credit rate varies from year-to-year based on the five-year U.S. Treasury bonds yield plus 0.25%. Employees' benefits under the plan are fully vested upon completion of three years of service. The Company's policy is to make contributions within the range determined by generally accepted actuarial principles. The costs of the Company's pension for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit plan on the consolidated balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in Accumulated other comprehensive income ("AOCI"). The projected benefit obligation of $230 exceeds the fair value of the plan assets of $200 as at December 31, 2011. Benefit cost of $182 and actuarial loss of $48 are reflected in earnings and other comprehensive income, respectively. The assumptions used in calculating the pension obligation include a discount rate of 4%, expected return on plan assets of 6% and rate of compensation increase of 4%. As at December 31, 2011, plan assets are invested in fixed income securities.

(r) Asset retirement obligations:

The Company completes periodic reviews of potential asset retirement obligations that may require recognition. The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations. Actual expenditures incurred are charged against the accumulated obligation. Based on APUC's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations have been recorded.

(s) Recognition of revenue:

Revenue derived from non-regulated energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

1. Significant accounting policies (continued)

(s) Recognition of revenue (continued):

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and waste water collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled revenues are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

Revenues related to utility energy sales and distribution are recorded based on metered energy consumptions by customers, which occurs on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns, line loss and current tariffs.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts is recognized based on actual tonnage at the expected price for the contract year.

Interest from long-term investments is recorded as earned.

(t) Foreign currency translation:

The Company's reporting currency is the Canadian dollar.

The Company's US operations are determined to have the U.S. dollar as their functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income ("OCI") and are accumulated in a component of equity on the consolidated balance sheet and are not recorded in income unless there is a complete sale or substantially complete liquidation of the investment.

As a result of the change relating to conversion of the Company from an income trust to a corporate structure at the end of 2009, the Company re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the US divisions operate. The Company concluded that the functional currency of the US operations of the Renewable Energy and Thermal Energy divisions has become the U.S. dollar. Consequently, these divisions have been prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37,605 resulting from the current rate translation of non-monetary items, principally property, plant and equipment and intangible assets, as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

1. Significant accounting policies (continued)

(u) Stock Based Compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan (“ESPP”); a deferred share unit (“DSU”) plan; and a performance share unit (“PSU”) plan. The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value using the Black-Scholes option pricing model. Liability classified awards are measured at fair value based on the average common share price over the five days immediately preceding the date of issue and at the end of the reporting period using the average over the days ending on the financial statement date.

(v) Income taxes:

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred assets and liabilities of a change in tax rates is recognized in earnings in the period that includes the date of enactment. Income tax credits are treated as a reduction to current income tax expense in the year the credit arises or future periods to the extent that realization of such benefit is more likely than not.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company follows FASB ASC 740-10 and recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(w) Financial instruments and derivatives:

APUC has classified its cash and cash equivalents, short term investments, and restricted cash as held-for-trading, which are measured at fair value. Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the respective asset’s carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company’s credit facility and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. Deferred financing costs, premiums and discounts on long- term debt are amortized using the effective interest method while deferred financing costs relating to revolving credit facilities are amortized on a straight-line basis over the term of the facility.

1. Significant accounting policies (continued)

(w) Financial instruments and derivatives (continued):

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values and the change in fair value is included in the Consolidated Statements of Operations. None of the derivatives were designated in hedging relationships for accounting purposes. The Company's derivative program is not designed or operated for trading or speculative purposes.

Liberty Utilities (West) enters into Power Purchase Agreements ("PPA") for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be marked-to-market and are accounted for on an accrual basis. We evaluate our counterparties on an on-going basis for non-performance risk to ensure it does not impact our conclusion with respect to this exemption.

(x) Fair Value Measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principle or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(y) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

1. Significant accounting policies (continued)

(z) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of deferred tax assets, assessments of asset retirement obligations, and the fair value of financial instruments, derivatives, share-based compensation and contingent consideration. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently Adopted Accounting Pronouncements

In December 2010, the FASB issued ASC update No. 2010-28, "Intangibles-Goodwill and Other (Topic 350), When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts, a consensus of the FASB Emerging Issues Task Force." This amendment modifies guidance for Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. The adoption of this update did not have a material impact on the Company's financial statements.

In December 2010, the FASB issued ASC update No. 2010-29, "Business Combinations (Topic 805), Disclosure of Supplementary Pro Forma Information for Business Combinations, a consensus of the FASB Emerging Issues Task Force." This amendment clarifies the periods for which pro forma financial information is presented. The acquisition of the California Utility occurred on January 1, 2011 and therefore the Statement of Operations for the year ended December 31, 2011 contains a full year of operating results from this acquisition. Accordingly pro forma financial statements would not provide any additional information. As the business combination was an acquisition of a division of the vendor for which comparable results from operations for the previous year are not available, pro forma financial statements for the comparative period are not provided as they cannot be practicably obtained. The adoption of this update did not have a material impact on the Company's financial statements.

In September 2011, the FASB issued ASC update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment". This Update revises how an entity tests goodwill for impairment. The new guidance allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity is no longer required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. As permitted by the Update, the Company has early adopted this standard in these annual financial statements for the year ended December 31, 2011. The adoption of this update did not have a material impact on the Company's financial statements.

2. Recently issued accounting pronouncements (continued)

(a) Recently Adopted Accounting Pronouncements (continued)

In June 2011, the FASB issued ASC update No. 2011-05 "Presentation of Comprehensive income (Topic 220)". This Update provides accounting guidance on presentation of comprehensive income. The new guidance eliminates the current option to report Other comprehensive income ("OCI") and its components in the statement of changes in stockholders' equity. The new guidance requires the changes in OCI be presented either in a single continuous statement of net income and OCI or in two separate but consecutive statements. As permitted by the Update, the Company has early adopted the presentation guidance in these annual financial statements for the year ended December 31, 2011. The amendments resulted in presentation changes only in the consolidated financial statements.

Subsequently in December 2011, the FASB issued ASC update No. 2011-12, "Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05". The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCI.

(b) Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This newly issued accounting standard requires an entity to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this accounting standard only requires enhanced disclosure, the adoption of this standard is not expected to have an impact our financial position or results of operations.

In May 2011, the FASB issued ASC update No. 2011-04 "Fair Value Measurement (Topic 820)". This Update amends the accounting and disclosure requirements for fair value measurements. The new guidance expands the disclosures about fair value measurements categorized within Level 3 of the fair value hierarchy and requires categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The new guidance will be effective for the Company's quarter ending March 31, 2012, and will be applied prospectively. Other than requiring additional disclosures, the adoption of this guidance is not expected to have a material impact on the Company's consolidated financial statements.

(in thousands of Canadian dollars except as noted and amounts per share)

3. Acquisitions

(a) Acquisition of California electrical generation and regulated distribution utility

On January 1, 2011, APUC and Emera Inc. ("Emera") closed the acquisition of the "California Utility" for a purchase price of approximately $135,343 (U.S. $136,077). Through its wholly owned subsidiary Liberty Energy (California), APUC owns 50.001% of the shares of California Pacific Utility Ventures LLC, which acquired the California Utility and has concluded it controls the acquired entity. Liberty Energy (California) provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The other 49.999% of the shares were acquired by Emera in the same transaction. The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition.

On April 29, 2011, Emera agreed to sell its 49.999% interest in Liberty Energy (California) to APUC in exchange for 8,211,000 shares of APUC. The transaction is subject to regulatory approval and is expected to close in 2012.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date, as well as the fair value at the acquisition date of the non-controlling interest in Liberty Energy (California):

Working capital	$ 8,964
Property, plant and equipment	146,064
Deferred income tax asset	2,056
Goodwill	8,268
Current portion of other long-term liabilities	(671)
Advances in aid of construction	(10,434)
Other long-term liabilities	(1,988)
Regulatory liabilities	(16,916)
Total net assets acquired	$135,343

The acquisition was funded as follows:

Contribution of equity by APUC in 2011	$ 29,074
Contribution of equity by APUC in 2010	3,787
Non-controlling interest portion of purchase price paid by Emera	32,860
Debt financing	69,622
Total acquisition consideration	$135,343

In connection with the acquisition, the Company issued 8,523,000 shares at a price of $3.25 per share to Emera pursuant to a subscription receipt agreement. The $27,700 cash proceeds of the subscription receipts were used to fund a portion of the cost of acquisition of the California Utility.

The determination of the fair value of assets and liabilities acquired has been based upon fair value measurements.

Goodwill is calculated as the excess of the purchase price over the fair value of net assets acquired and the contributing factors to the amount recorded include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. All of the goodwill was allocated to the Liberty Utilities (West) segment.

3. Acquisitions (continued)

(a) Acquisition of California electrical generation and regulated distribution utility (continued):

Property, plant & equipment of Liberty Energy (California) are amortized on a straight line basis, ranging from 15 to 75 years in accordance with regulatory requirements.

The Company incurred $2,572 in total acquisition-related costs (2010 - $2,210); of which $362 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

As the acquisition closed on January 1, 2011, the financial statements for the year ended December 31, 2011 contain a full year of operating results for the utility. Liberty Energy (California) contributed revenue of $77,367 and earnings of $2,987 to the Company's results for the year ended December 31, 2011. The disclosure of pro forma revenue and earnings related to 2010 is impracticable since the assets acquired were part of a small division of a much larger utility; separate financial statements were not maintained by the vendor of the assets, the regulated tariff driving revenue formulae has changed, the rate-base used in determining rates was not identical to the assets acquired and the operating costs were subject to extensive allocation.

(b) Acquisition of Regulated Water Utilities

On September 20, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of Noel Water Co., Inc. ("Noel"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $903 was paid in cash. The following assets were acquired at fair values: working capital of $28 and property, plant and equipment of $729. Goodwill amounting to $146 was recognized.

On November 9, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of KMB Utility Corporation ("KMB"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $350 was paid in cash. The following assets were acquired at fair values: working capital of $43 and property, plant and equipment of $265. Goodwill amounting to $42 was recognized.

Both utilities are located in the state of Missouri.

(c) Agreement to Acquire New Hampshire Electric and Gas Utilities

On December 9, 2010, Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company, a regulated electric utility, and EnergyNorth Natural Gas Inc. a regulated natural gas utility from National Grid USA ("National Grid") for total cash consideration of U.S. $285,000 plus working capital and subject to a final closing adjustment.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12,000,000 APUC common shares upon closing of the transactions at a purchase price of $5.00 per share. The receipt of cash from Emera and issuance of the shares is contingent on closing of these acquisitions and consequently the subscription receipts have not been recorded in the financial statements.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

3. Acquisitions (continued)

(c) Agreement to Acquire New Hampshire Electric and Gas Utilities (continued)

The Company incurred $3,271 in total acquisition-related costs (2010 - $1,889); of which $1,382 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

(d) Agreement to Acquire Mid-West Gas Utilities

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos Energy Corporation ("Atmos Energy") to acquire certain regulated natural gas distribution utility assets (the "Mid-West Utilities") located in Missouri, Iowa, and Illinois. Total purchase price for the Mid-West Utilities is approximately U.S. $124,000, subject to certain working capital and other closing adjustments.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

The Company incurred $398 in total acquisition-related costs during 2011 (2010 - $nil). All such costs have been expensed in the consolidated Statement of Operations.

(e) Agreement to Acquire Solar Energy Project

On November 27, 2011, APCo entered into agreements to acquire rights, subject to Ontario Power Authority approval, to develop a 10 MW-AC solar project located near Cornwall, Ontario which has been granted an Ontario Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the power sale contract is $4,500 plus additional contingent consideration of $3,500 that is based on achieving certain construction milestones.

On December 30, 2011 Ontario Power Authority Approval was received and the transaction closed on January 4, 2012. Following the completion of all regulatory submissions and approvals, construction of the solar facility is expected to begin in the second half of 2012, with a commercial operation date estimated in early 2013.

(f) Power Purchase agreement for Chaplin Wind Project

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement with SaskPower for development of a 177 –MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan. The project has a targeted commercial operation date of December, 2016. The 25 year power purchase agreement features a rate escalation provision of 0.6% throughout the term of the agreement.

(g) Highground Capital Corporation

In 2008, the Company entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and the Company issued equity in the form trust units to the Highground shareholders and CJIG, in exchange for $26.2 million of cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

(in thousands of Canadian dollars except as noted and amounts per share)

3. Acquisitions (continued)

(h) Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind projects in the United States from Gamesa Corporación Tecnológica, S.A. ("Gamesa") for total consideration of approximately U.S. $269 million. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissionings near the end of 2012.

4. Accounts receivable

Accounts receivable as of December 31, 2011, include unbilled receivables of $11,304 (December 31, 2010 - $1,552) in the regulated utilities. The unbilled revenue is an estimate of the amount of utility revenue since the date the meters were last read.

5. Long-term investments and notes receivable

Long-term investments and notes receivable consist of the following:

	2011	2010
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 4,926	$ 8,197
25% of Class B non-voting shares of Cochrane Power Corporation	5,382	5,775
45% interest in the Algonquin Power (Rattle Brook) Partnership	3,784	3,790
50% interest in the Valley Power Partnership	1,676	1,845
Red Lily Subordinated loan, interest at 12.5% (b)	6,565	6,565
Red Lily Senior loan, interest at 6.31% (b)	13,000	6,100
Chapais Énergie, Société en Commandite 12.1% interest in Tranche A and Tranche B term loans		
The loans bear interest at the rate of 10.789% and 4.91%, respectively	2,913	3,329
Silverleaf resorts loan, interest at 15.48% (c)	2,056	2,010
Note Receivable - Twin Falls. The note bears interest at the rate of 6.75%	—	740
	40,302	38,351
Less: current portion	(482)	(1,172)
Total long term investments and notes receivable	$39,820	$37,179

The above notes are secured by the underlying assets of the respective facilities. There is no allowance for doubtful account in regards to the notes receivable as at December 31, 2011 and 2010.

5. Long-term investments and notes receivable (continued)

(a) Red Lily I

The Red Lily I Partnership ('Partnership") is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 megawatt wind energy facility located in south-eastern Saskatchewan.

The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility from the Partnership. APUC has advanced $13,000 (2010 - $6,100) under a senior debt facility to the Partnership. Another third party lender has also advanced $31,000 of senior debt to the Partnership. The Company's senior loan to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including APUC's portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as at December 31, 2011 was determined to be negligible.

During the year ended December 31, 2011, APUC advanced $6,900 of the senior debt to the Partnership. As of December 31, 2011 APUC has funded a total of $13,000 (December 31, 2010 - $6,100) of the senior debt and $6,565 (December 31, 2010 - $6,565) of the subordinated debt.

(b) Silverleaf Resorts Inc – Hill County

On July 29, 2010, Liberty Water, a wholly owned subsidiary of APUC, made an investment in its Hill Country facility, a part of Silverleaf Resorts Inc.'s ("SRI") facilities in Comal County, Texas. The investment of $2,056 (U.S. $2,021) was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. This investment has been recorded in property, plant and equipment as additional capacity conveyed by SRI together with note receivable for funds advanced by APUC.

The note has a 10 year term and bears interest at 15.48%. The note is repayable in cash to the extent expansion does not form part of the rate base of the utility during the 10 year term. To the extent that the cost of the expansion becomes part of the rate base of the utility, the note will be assigned as payment to Silverleaf for the expansion costs with the excess received in cash.

(in thousands of Canadian dollars except as noted and amounts per share)

6. Property, plant and equipment

Property, plant and equipment consist of the following:

2011

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$ 527,922	$ 132,779	$ 395,143
Thermal	194,080	78,776	115,304
Distribution			
Water & wastewater	239,190	48,716	190,474
Electricity	154,154	2,636	151,518
Land	12,203	—	12,203
Equipment	50,823	23,429	27,394
Construction in progress	53,920	—	53,920
	$ 1,232,292	$ 286,336	$ 945,956

2010

	Cost	Accumulated depreciation	Net book value
Generation			
Renewable	$ 527,407	$ 114,780	$ 412,627
Thermal	191,138	69,816	121,322
Distribution			
Water & wastewater	219,744	41,840	177,904
Electricity	—	—	—
Land	11,976	—	11,976
Equipment	48,720	21,309	27,411
Construction in progress	10,500	—	10,500
	$ 1,009,485	$ 247,745	$ 761,740

Generation assets are those used to generate electricity. These assets include hydroelectric, wind and thermal generation stations, turbines, dams, reservoirs and other related equipment.

Electricity distribution assets are those used to distribute electricity within a specific geographic service territory to end users of electricity. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Water and waste water assets are those used to distribute water and collect wastewater. These assets include treating facilities and equipment, network of supply mains, pipes and canals, pumps and related generation equipment, meters, hydrants, collecting sewers and other related equipment.

Equipment assets include equipment, vehicles, inventory and information technology assets.

Renewable generation assets include cost of $94,606 (2010 - $94,606) and accumulated depreciation of $30,264 (2010 - $27,962) related to facilities under capital lease or owned by consolidated variable interest entities. Depreciation expense of facilities under capital lease was $2,302 (2010 - $2,536). Contributions received in aid of construction of $3,968 (2010 - $3,731) have been credited to the cost of the distribution assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

(in thousands of Canadian dollars except as noted and amounts per share)

6. Property, plant and equipment (continued)

Equipment includes cost of $4,227 (2010 - $4,402) and accumulated depreciation of $2,079 (2010 - $2,149) related to equipment under capital lease. Depreciation expense of equipment under capital lease was $282 (2010 - $292).

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1,370 (2010 - $1,836) representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end the Company entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $200. As a result, the Company wrote down its investment in these hydro facilities to fair value, less costs associated with the sale, and recognized a charge on property, plant and equipment of $662 (2010 - $656).

In December 2011, Liberty Utilities (South) wrote down $1,058 from facilities assets based on regulatory decisions in 2011 that these costs are not capitalizable for rate-base purposes.

7. Intangible assets

Intangible assets consist of the following:

2011

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 60,044	$ 20,548	$39,496
Customer relationships	19,235	3,462	15,773
Energy sales contract	—	—	—
	$ 79,279	$ 24,010	$55,269

2010

	Cost	Accumulated amortization	Net book value
Power sales contracts	$102,980	$ 45,345	$57,635
Customer relationships	18,811	2,912	15,899
Energy sales contract	4,228	3,876	352
	$126,019	$ 52,133	$73,886

Subsequent to the year end, the Region of Peel elected not to extend the existing waste processing contract with the Company and will instead seek competitive proposals from several waste management companies, including the Company. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and the Company recognized a charge on intangible assets of $13,430.

Estimated amortization expense for intangibles for the next five years is $4,190 each year.

8. Regulatory assets and liabilities

The Company's regulated utility operating companies owned by Liberty Utilities are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process.

The utilities periodically file rate cases with their regulators. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Regulated utilities use a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Liberty Utilities monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments. In the case of Liberty Utilities (West) and consistent with regulated utilities operating in California, the utility is required to make general rate case filings on a regular 3 year cycle. The utilities' most recent rate case was settled in 2009. The rate case was filed in February 2012 for the prospective years of 2012-2013. The regulator allows for the use of a prospective test year in the establishment of rates for the utility. The regulator also allows the use of annual adjuster mechanisms to account for inflation to labor and other expenses over the three year period of the rate case filing. In addition, a utility's rates include thresholds for capital expenditures, which once reached, can trigger adjustment mechanisms in between rate cases.

Energy Cost Adjustment Clause ("ECAC")

A portion of the revenue of Liberty Utilities (West) consists of ECAC which is designed to recoup or refund power supply costs that are caused by the fluctuations in the price of fuel and purchased power. The ECAC allowed in California mitigates the impact of changes in fuel prices and stabilizes earnings by allowing for the recovery of fuel and purchased power costs by updating rates charged on an annual basis. The mechanism consists of a base rate and amortization rate. The actual power supply costs incurred are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows Calpeco to request an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

The Post Test Year Adjustment Mechanism ("PTAM")

The PTAM allows Calpeco to update its rates annually by a cost inflation index. In addition, rates are allowed to be updated to recover the return on investment and associated depreciation of major capital projects.

(in thousands of Canadian dollars except as noted and amounts per share)

8. Regulatory assets and liabilities (continued)

Power Purchase Agreement ("PPA")

Liberty Utilities (West) has entered into a five year all requirements PPA with NV Energy to provide its full electric needs at NV Energy's "system average cost" rates. The PPA had an effective starting date of January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply Liberty Utilities (West) with sufficient renewable power to satisfy the current 20% California Renewables Portfolio Standard requirement for the five-year term of the PPA. NV Energy's deliveries under the PPA are structured in a manner which satisfies the CPUC resource adequacy ("RA") requirements, and are designed to enable Liberty Utilities (West) to comply with the associated RA reporting requirements. Liberty Utilities (West) accounts for the PPA as an operating lease. The costs associated with the PPA are recoverable through the ECAC.

Regulatory assets and liabilities consist of the following:

	December 31, 2011	December 31, 2010
Regulatory assets:		
Rate case costs (i)	$ 2,161	$ 2,164
Alternative revenue program (ii)	2,789	320
Water testing costs (iii)	79	—
Total regulatory assets	$ 5,029	$ 2,484
Less current regulatory assets	2,458	—
Non-current regulatory assets	$ 2,571	$ 2,484
Regulatory liabilities		
Deferred energy costs (iv)	$ 6,708	$ —
Cost of removal (v)	14,945	—
Total regulatory liabilities	$ 21,653	$ —
Less current regulatory liabilities	2,469	—
Non-current regulatory liabilities	$ 19,184	$ —

(i) Rate case

The costs to file, prosecute and defend rate case applications are referred to as rate case costs and are generally recoverable, in whole or in part, as part of the rate case process over a prescribed period of time. Deferred rate case costs are those rate case costs the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

8. Regulatory assets and liabilities (continued)

(ii) Alternative revenue program

A rate decision by the regulator of one of Liberty Utilities (South)'s utilities has ordered a phase-in of the rate increases it has granted wherein the full rate increase will be phased in over a 12 month period. The phase-in also includes a surcharge mechanism that ensures the utility is not disadvantaged by the phase in of the new rates.

(iii) Water testing costs

Water testing costs consist of certain expenses associated with some water testing costs ordered by the regulator. These costs are allowed to be recovered in rates in future periods. The regulatory asset associated with these costs is amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

(iv) Deferred energy cost

Certain state statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased gas, fuel and purchased power.

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the consolidated statement of operations but rather is deferred and recorded as a regulatory asset on the balance sheet in accordance with the provisions of ASC 980. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to regulatory review. The Utilities also record and are eligible under the statute to recover a carrying charge on such deferred balances.

(v) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant.

Future implications of discontinuing application of regulatory accounting

Liberty Utilities regularly assesses whether it can continue to apply regulatory accounting to its operations. In the event that the criteria no longer applied to a deregulated portion of the operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory mechanism is provided. Additionally, these factors could results in an impairment on utility assets.

8. Regulatory assets and liabilities (continued)

Income statement impact of applying regulatory accounting

If Liberty Utilities had not applied regulatory accounting earnings would have been affected as follows:

	December 31, 2011	December 31, 2010
Liberty Utilities (South):		
As a result of not recognizing the alternative revenue program in advance of the full rate increase being phased in rates, the rate case costs would have been expensed as incurred and revenue recognized would have been limited to the current phase of the phase-in plan.	$ (1,825)	$ (332)
Liberty Utilities (West):		
Recognizing over-recovered purchased power costs net of capitalized rate-case that would have been expensed.	4,106	—
Total increase (decrease) in earnings	$ 2,281	$ (332)

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long-term liabilities

Long term liabilities consist of the following:

	2011	2010
APCo		
Senior Unsecured Notes: $135,000 senior unsecured notes, interest rate of 5.5% maturing July 25, 2018. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012.	$134,778	$ —
Senior Secured Revolving Credit Facility: Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 2.5%.	—	64,500
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly interest and principal installments of $402 and maturing December, 2027.	39,033	39,844
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2011 is 2.05% (2010 – 1.33%).	19,526	19,096
Senior Debt Chute Ford: Interest rate of 11.6% repayable in blended monthly interest and principal installments of $64 and maturing April, 2020.	4,072	4,350
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matured on October 31, 2011. Monthly interest and quarterly principal payments totaled $72,146 (2010 - $1,741). The effective rate of interest for 2011 was 1.38% (2010 – 1.81%).	—	68,789
Bonds Payable: Obligation to the City of Sanger (2010 - U.S. $230).	—	229
Liberty Utilities		
Senior Notes – California Pacific Electric Company, LLLC: U.S. $45,000 senior unsecured notes, interest rate of 5.19%, maturing December 29, 2020 and U.S. $25,000, interest rate of 5.59%, maturing December 29, 2025. The notes are interest only, payable semi-annually.	71,190	—

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long term liabilities (continued)

	2011	2010
Senior Unsecured Notes – Liberty Water Co:		
U.S. $50,000 senior unsecured notes, interest rate of 5.6% maturing December 22, 2020. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and an annual principal repayment of U.S. $5,000 thereafter.	50,850	49,730
Litchfield Park Service Company Bonds:		
1999 and 2001 IDA Bonds. Interest rates of 5.95% and 6.75% repayable in blended semi-annual installments maturing October 2023 and October 2031. Principal payments of U.S. $270 (2010 – U.S. $255). The balance of these notes at December 31, 2011 was U.S. $3,605 and U.S. $7,100, respectively (2010 – U.S. $3,810 and U.S. $7,165).	11,868	11,931
Bella Vista Water Loans:		
Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March, 2020 and December, 2017. The balance of these notes at December 31, 2011 was US$1,275 and US$83 respectively (2010 – US$1,384 and US$95)	1,399	1,489
	$ 332,716	$ 259,958
Less: current portion	(1,624)	(70,490)
	$ 331,092	$ 189,468

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to APUC, APCo or Liberty Utilities. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions/dividends to Liberty Utilities, APCo and APUC from the specific facilities.

APCo

On July 25, 2011 APCo completed a $135,000 private placement debt financing commitment at a price of $998.28 per $1,000 principal amount of debenture. The notes are senior unsecured with a seven year maturity date of July 25, 2018 and bear interest at 5.5%. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012. APCo incurred deferred financing costs of $1,685, which are being amortized to interest expense over the term of the loan using the effective interest rate method. The net proceeds of this financing were used to retire the project debt related to the St. Leon facility (Air Source Senior Debt Financing) and to reduce amounts outstanding on APCo's senior secured revolving credit facility. As of December 31, 2011, the Company had accrued $3,255 in interest payable.

9. Long term liabilities (continued)

In February 2011, APCo renewed its senior secured revolving credit facility in the maximum amount of $142,000 (the “Facility”) for a three year term with its Canadian bank syndicate. The Facility now has a maturity date of February 14, 2014. Refinancing costs and fees related to the renewal of $1,446 have been recorded as deferred financing costs in the period. On July 25, 2011, in conjunction with the APCo debenture offering discussed above, the maximum availability on the senior revolving facility was reduced to $120,000. At December 31, 2011, $0 (2010 - $64,500) has been drawn on the Facility. In addition, the availability of the revolving credit facility has been reduced for certain outstanding letters of credit in amounts totaling $39,606 (2010 - $33,122).

Therefore, APCo had $80,394 of undrawn bank facilities as at December 31, 2011. The terms of the Facility contain certain financial covenants including debt service ratios and leverage ratios which can limit the amounts available for borrowing. Based on current covenants at December 31, 2011, APCo is able to access the entire undrawn amount of the Facility. The facility is secured by a fixed and floating charge over all APCo entities.

On December 22, 2010 APUC’s subsidiary, Liberty Water Co. (“Liberty Water”), issued U.S. $50,000 senior unsecured notes with a ten year maturity date of December 2020 and bearing interest at 5.6%. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and annual principal repayments of U.S. $5,000 thereafter. As of December 31, 2011, Liberty Water incurred deferred financing costs of $1,235 (2010 - $854) which are being amortized to interest expense over the term of the loan using the effective interest rate method.

APUC’s subsidiary California Pacific Electric Company, LLC has issued U.S.$70,000 senior unsecured notes consisting of U.S. $45,000 bearing an interest rate of 5.19% maturing December 29, 2020 and U.S. $25,000 bearing an interest rate of 5.59% maturing December 29, 2025. The notes are interest only, payable semi-annually. Financing costs of $ 1,048 (2010 - $1,069) incurred with respect to this placement have been recorded in deferred financing costs.

Subsequent to year-end, on January 19, 2012, Liberty Utilities Co. entered into an agreement for a U.S. $80,000 senior unsecured revolving credit facility with a three year term at an interest rate equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.75%.

Interest paid on the long-term liabilities was $18,089 (2010 - $9,064).

(in thousands of Canadian dollars except as noted and amounts per share)

9. Long term liabilities (continued)

Principal payments due in the next five years and thereafter are:

	2012	2013	2014	2015	2016	Thereafter	Total
APCo							
Senior Unsecured	$ —	$ —	$ —	$ —	$ —	$ 134,778	$ 134,778
Senior Debt Long Sault Rapids	897	993	1,094	1,211	1,340	33,498	39,033
Sanger Bonds	—	—	—	—	—	19,526	19,526
Senior Debt Chuteford	309	346	389	436	489	2,103	4,072
Liberty Utilities							
Senior Unsecured	—	—	—	—	5,085	45,765	50,850
Senior Unsecured	—	—	—	—	—	71,190	71,190
Litchfield Park Service Company Bonds	290	305	326	346	366	10,235	11,868
Bella Vista Water Loans	128	136	135	144	140	716	1,399
Total	$ 1,624	$ 1,780	$ 1,944	$ 2,137	$ 7,420	$ 317,811	$ 332,716

(in thousands of Canadian dollars except as noted and amounts per share)

10. Convertible Debentures

2011	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$ 4.08	$ 6.00	$ 4.20	
Carrying value at December 31, 2010	$ 59,156	$ 59,699	$62,905	$181,760
Conversion to shares (Note12), net of costs	(59,449)	(10)	(334)	(59,793)
Amortization and accretion	293	37	—	330
Carrying value at December 31, 2011	$ —	$ 59,726	$62,571	$122,297
Face value at December 31, 2011	$ —	$ 59,957	$62,571	$122,528

2010	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$ 4.08	$ 6.00	$ 4.20	
Carrying value at December 31, 2009	$ 62,686	$ 59,664	$63,250	$185,600
Conversion to shares (Note 12), net of costs	(4,473)	—	(345)	(4,818)
Amortization and accretion	943	35	—	978
Carrying value at December 31, 2010	$ 59,156	$ 59,699	$62,905	$181,760
Face value at December 31, 2010	$ 62,470	$ 59,967	$62,905	$185,342

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC (note 12).

(in thousands of Canadian dollars except as noted and amounts per share)

10. Convertible Debentures (continued)

The Series 3 debentures are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares per $1,000 principal amount of debentures. The debentures cannot be redeemed by APUC on or before December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 debentures' maturity, APUC can redeem the Series 3 debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 debentures with additional shares.

11. Other long-term liabilities

Other long term liabilities consist of the following:

	2011	2010
Contingent consideration	$ 1,080	$ 1,198
Deferred water rights inducement	2,927	3,008
Customer deposits	2,483	1,985
Capital Leases		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	501	535
Other	5,073	5,099
	12,064	11,825
Less: current portion	(1,641)	(1,011)
	$10,423	$10,814

12. Shareholders' Capital

Number of common shares:

	2011	2010
Common shares, beginning of period	95,422,778	93,064,120
Conversion and redemption of convertible debentures	15,300,824	1,178,478
Issuance pursuant to management internalization	—	1,180,180
Issuance of shares	25,399,178	—
Common shares, end of period	136,122,780	95,422,778

12. Shareholders' Capital (continued)

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are authorized or outstanding.

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC. As at December 31, 2011, APUC does not have any issued and outstanding preferred shares.

On June 29, 2010, the Company issued 1,180,180 shares valued at $4,763 pursuant to the Management Internalization Agreement signed on December 21, 2009. The issuance of shares and final settlement was approved by the Company's shareholders at its annual general meeting held on June 23, 2010.

In 2010, $4,473 principal amount of New Series 1 Debentures were converted at the option of the holders at a price of $4.08 for each share into 1,096,336 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $4,094 has been recorded as share capital.

In 2010, $345 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 82,142 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $311 has been recorded as share capital.

On April 1, 2011, APUC called for the redemption of the Series 1A Debentures on May 16, 2011 ("Redemption Date"). Prior to the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On May 16, 2011, APUC redeemed the remaining Series 1A Debentures by issuing and delivering 430,666 APUC shares. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

During the year ended December 31, 2011, $10 principal amount of Series 2A Debentures were converted at the option of the holders at a price of $6.00 for each share into 1,666 shares of APUC.

During the year ended December 31, 2011, $334 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 79,517 shares of APUC.

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC.

Subsequent to the year end, $66 principal amount of Series 3 Debentures were converted at the option of the holders into 15,711 shares of APUC.

12. Shareholders' Capital (continued)

Shareholders' Rights Plan

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan"). The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

Dividend reinvestment plan

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional Common Shares acquired through the reinvestment of cash dividends will be purchased in the open market or will be issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time.

Employee Share Purchase Plan

In September 2011, the Company approved an employee share purchase plan ("ESPP") which commenced in October 2011. Eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match a) 20% of employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and b) 15% of employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2011, a total of 7,176 common shares were issued to employees under the ESPP plan for a total compensation expense related to the ESPP in 2011 of $9.

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' Capital (continued)

Stock Option Plan

During 2010, the Company's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

The following assumptions were used in determining the fair value of share options granted:

	2011	2010
Risk-free interest rate	3.0%	2.9%
Expected volatility	30%	29%
Expected dividend yield	5.3%	5.9%
Expected life	8 years	8 years
Weighted average grant date fair value per option	$ 0.99	$ 0.61

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' Capital (continued)

Stock option activity during the period is as follows:

	Number of shares	Weighted average exercise price	Weighted average remaining contractual term	Aggregate intrinsic value
Balance at January 1, 2011	1,160,204	$ 4.05	7.62	$ 1,056
Granted	1,326,900	5.38	8.00	22
Balance at December 31, 2011	2,487,104	$ 4.76	6.96	$ 4,134
Exercisable at December 31, 2010	386,735	$ 4.05	6.62	$ 917

On March 14, 2012, 1,194,606 stock options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $6.22.

Directors Deferred Share Units

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company expects to settle these instruments in cash, these DSUs are accounted for as liability awards and dividends accumulated are recognized as additional compensation cost. The DSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period. As at December 31, 2011, no DSUs had been issued.

(in thousands of Canadian dollars except as noted and amounts per share)

12. Shareholders' Capital (continued)

Performance Share Units

The Company approved a performance share unit plan to its employees as part of the Company's long-term incentive program. Performance share units ("PSUs") are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of shares issued can range from 0% to 144% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividend's are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized ratably over the performance period based on the Company's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest

A summary of the PSUs activity follows:

	Employees PSUs Outstanding
December 31, 2010	—
Granted	21,123
December 31, 2011	21,123

A summary of the non-vested PSUs follows:

	Employees PSUs	
	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2011	—	$ —
Granted	21,123	5.62
Non-vested at December 31, 2011	21,123	$ 5.62

Share-based compensation

For the year ended December 31, 2011, APUC recorded $769 (2010 - $108) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1,216 and $70 respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

(in thousands of Canadian dollars except as noted and amounts per share)

13. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the year ended December 31, 2011, the Company declared cash dividends to shareholders totaling $32,426 (2010 - $22,765) or $0.24 per common share (2010 - $0.24 per common share).

On November 14, 2011, the Board declared a dividend on the Company's shares of $0.07 per share payable on January 16, 2012 to the shareholders of record on December 30, 2011 for the period from October 1, 2011 to December 31, 2011.

14. Income Taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 28.25% (2010 - 31%). The differences are as follows:

	2011	2010
Expected income tax expense / (recovery) at Canadian statutory rate	$ 1,204	$ (45)
Increase (decrease) resulting from:		
Recognition of deferred credit	(6,581)	(6,636)
Differences in tax rates in subsidiaries and changes in tax Rates	(861)	(202)
Change in valuation allowances	(16,834)	(5,979)
Foreign exchange on intercompany items	2,250	(6,228)
Non-taxable corporate dividend	(1,418)	(1,191)
Non-controlling interests share of income	(1,317)	—
Other permanent difference	518	(510)
Income tax recovery	$ (23,039)	$ (20,791)

For the years ended December 31, 2011 and 2010, income/(loss) before taxes consists of the following:

	2011	2010
Canadian operations	$(5,242)	$(6,405)
U.S. operations	9,505	4,007
	$ 4,263	$(2,398)

(in thousands of Canadian dollars except as noted and amounts per share)

14. Income Taxes (continued)

As a result of the business combination transaction in 2009, APUC recorded certain additional tax attributes. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration was reflected as a deferred credit of $55,647 on the transaction date. The deferred credit is being recognized in income as a deferred income tax recovery in relative proportion to the amount of the related deferred tax assets that are utilized in the period.

Income tax expense (recovery) attributable to income/(loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2011			
Canada	$ 268	$ (1,936)	$ (1,668)
United States	32	(21,403)	(21,371)
	$ 300	$(23,339)	$(23,039)
Year ended December 31, 2010			
Canada	200	(1,081)	(881)
United States	(269)	(19,641)	(19,910)
	$ (69)	$(20,722)	$(20,791)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 are presented below:

	2011	2010
Deferred income tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ 133,625	$ 120,973
Unrealized foreign exchange difference on intercompany notes	—	17,860
Customer advances in aid of construction	6,610	5,559
Regulatory liabilities	4,313	—
Foreign exchange hedges and interest rate swaps	2,233	1,459
Total deferred income tax assets	146,781	145,851
Less: Valuation allowance	(15,063)	(31,896)
Total deferred income tax assets	131,718	113,955
Deferred tax liabilities:		
Property, plant and equipment	(96,158)	(96,554)
Intangible assets	(7,812)	(7,639)
Other	(1,009)	(1,697)
Total deferred income tax liabilities	(104,979)	(105,890)
Net deferred income tax assets	$ 26,739	$ 8,065

(in thousands of Canadian dollars except as noted and amounts per share)

14. Income taxes (continued)

The valuation allowance for deferred tax assets as of December 31, 2011 and 2010 was $15,062 and $31,896, respectively. The net change in the total valuation allowance was a decrease of $16,834 in 2011 and a decrease of $5,979 in 2010. The valuation allowance at December 31, 2011 was primarily related to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carry back and carry forward periods), projected deferred taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

	2011	2010
Current deferred income tax asset	$ 13,022	$ 14,015
Non-current deferred income tax asset	67,671	74,006
Current deferred income tax liability	(723)	(514)
Non-current deferred income tax liability	(53,231)	(79,442)
	$ 26,739	$ 8,065

As at December 31, 2011, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital losses carry forwards
2015	$ 28,406
2026 and onwards	239,823
	$ 268,229

15. Related party transactions

Certain executives of APUC are shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of APCo. A member of the Board of Directors of APUC is an executive at Emera.

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for year ended December 31, 2011 were $327 (2010 - $327).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year, APUC incurred costs in connection with the use of the aircraft of $453 (2010 - $430) and amortization expense related to the advance against expense reimbursements of $274 (2010 - $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

15. Related party transactions (continued)

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008, increasing by 2.5% every 5 years to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $314 for the year ended December 31, 2011 (2010 - $266). APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

APMI is one of the two original developers of Red Lily I (note 5(b)) and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") which is an entity where Senior Executives hold equity interests. APUC and APS agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.

As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.

A contract with a subsidiary of Emera to purchase energy on Independent System Operator New England ("ISO NE") and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, APUC paid a subsidiary of Emera an amount of $0 (2010 - $1,368) which was included as an operating expense on the consolidated statement of operations.

In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During 2011 APUC paid U.S. $260 (2010 - $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). For 2011, the Energy Services Business sold electricity amounting to $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

(in thousands of Canadian dollars except as noted and amounts per share)

15. Related party transactions (continued)

As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including Sanger repowering project, the acquisition of the Clean Power Income Fund and the development of the Red Lily I wind project. The Company is currently evaluating the impact the settlement will have on the consolidated financial statements.

16. Interest, dividend and other income

Interest, dividend and other income includes the following items:

	2011	2010
Interest income	$2,533	$1,138
Dividend income	2,928	2,928
Equity income	193	431
Other	5	667
	$5,659	$5,164

17. Other revenue

Other revenue consists of the following:

	2011	2010
Hydro mulch sales	$1,352	$1,318
Red Lily development fees	209	209
Red Lily royalty income and supervisory fees	947	—
Red Lily construction services fees and natural gas sales	757	1,804
Gain on sale of assets	358	—
Other	20	—
	$3,643	$3,331

18. Commitments and Contingencies

Land and Water Lease Commitments:

Certain of the Company’s operating entities have entered into agreements to lease either land, water rights or both that are used in the generation of electricity or to pay, in lieu of property tax, an amount based on electricity production. The terms of these leases have varying maturity dates that continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. APUC incurred costs of $2,654 during 2011 (2010 - $2,231) in respect of these agreements for all of its operating entities.

Contingencies:

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC’s exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

On December 19, 1996, the Attorney General of Québec (“Québec AG”) filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation (the “Seaway Management”) under its water lease with Seaway Management. The water lease contains a “hold harmless” clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the “Federal Authorities”) into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $5.4 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, the Company accrued $1,000 of water lease owed to Québec AG for the years 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $300 related to these years were also recorded in 2011.

(in thousands of Canadian dollars except as noted and amounts per share)

18. Commitments and Contingencies (continued)

Other Commitments:

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2011.

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated the remaining potential remedial measures involving capital expenditures to be approximately $16,900 which may be required to comply with the legislation and which would be invested over a five year period or longer.

APUC has outstanding purchase commitments for long-term service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

	2012	2013	2014	2015	2016	Thereafter	Total
Long term service agreements	$ 4,559	$ 4,072	$ 4,153	$ 4,236	$ 4,321	$ 73,008	$ 94,349
Purchased power	45,053	45,155	46,375	45,867	45,053	—	227,503
Capital projects	7,871	—	—	—	—	—	7,871
Operating leases	939	609	369	282	20	—	2,219
Total	**$ 58,422**	**$ 49,836**	**$ 50,897**	**$ 50,385**	**$ 49,394**	**$ 73,008**	**$ 331,942**

Liberty Utilities (West) has entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2011. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

(in thousands of Canadian dollars except as noted and amounts per share)

19. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the Company and the weighted average number of shares outstanding during the year. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs, shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the treasury stock method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the as if converted method. The weighted average shares outstanding during the year are as follows:

	2011	2010
Weighted average shares – basic	116,712,934	94,338,193
Dilutive effect of share-based awards	249,854	—
Weighted average shares – diluted	116,962,788	94,338,193

The shares potentially issuable as a result of the convertible debentures and 1,326,900 stock options (2010 –1,160,204) are excluded from this calculation as they are anti-dilutive.

20. Non-cash operating items

The changes in non-cash operating items is comprised of the following:

	2011	2010
Accounts receivable	$ (11,674)	$ (6,817)
Related party balances	145	—
Supplies and consumable inventory	(1,087)	—
Income tax receivable	(133)	1,143
Prepaid expenses	(2,071)	1,153
Accounts payable	3,991	5,050
Accrued liabilities	9,010	—
Current income tax liability	207	195
Net regulatory assets and liabilities	70	(809)
	$ (1,542)	$ (85)

21. Segmented Information

APUC has two operating segments: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric distribution services.

Within APCo there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Effective July 2011, the Company changed its operational segments within Liberty Utilities to be aggregated and reported by geography territory. As a result Liberty Utilities reports results under Liberty Utilities (West) Region (currently consisting of Calpeco) and Liberty Utilities (South) Region (currently consisting of Liberty Water). No changes in the aggregation of segmented financial information were required as a result of this change. As additional utilities are acquired, additional reportable segments by geographic territory may be added.

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy and Liberty Utilities (South) and Liberty Utilities (West). The development activities of APCo are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the loss on financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The interest rate swaps relate to specific debt facilities and gains and losses are allocated in the same manner as interest expense. Amounts relating to the convertible debentures are reported in the corporate segment.

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

The results of operations and assets for these segments are as follows:

	Year ended December 31, 2011							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non-regulated energy sales	$ 87,566	$ 46,666	$134,232	$ —	$ —	$ —	$ —	$ 134,232
Regulated energy sales and distribution	—	—	—	—	77,368	77,368	—	77,368
Waste disposal fees	—	16,406	16,406	—	—	—	—	16,406
Regulated water reclamation and distribution	—	—	—	44,989	—	44,989	—	44,989
Other revenue	2,291	1,352	3,643	—	—	—	—	3,643
Total revenue	89,857	64,424	154,281	44,989	77,368	122,357	—	276,638
Operating expenses	29,802	44,485	74,287	22,720	62,511	85,231	38	159,556
	60,055	19,939	79,994	22,269	14,857	37,126	(38)	117,082
Depreciation of property, plant and equipment	(16,903)	(10,684)	(27,587)	(7,993)	(3,813)	(11,806)	—	(39,393)
Amortization of intangible assets	(3,007)	(2,735)	(5,742)	(691)	—	(691)	—	(6,433)
Administration expenses	(10,719)	(700)	(11,419)	(342)	(798)	(1,140)	(4,975)	(17,534)
Write down of long-lived assets	(2,032)	(13,430)	(15,462)	(1,058)	—	(1,058)	—	(16,520)
Gain on foreign exchange	—	—	—	—	—	—	652	652
Interest expense	(8,128)	(1,688)	(9,816)	(5,189)	(4,526)	(9,715)	(10,910)	(30,441)
Interest, dividend and other income	2,143	(6)	2,137	488	—	488	3,034	5,659
Acquisition related costs	—	—	—	(2,301)	(466)	(2,767)	(198)	(2,965)
Loss on derivative financial instruments	(1,068)	—	(1,068)	—	—	—	(4,776)	(5,844)
Earnings / (loss) before income taxes	$ 20,341	$ (9,304)	$ 11,037	$ 5,183	$ 5,254	$ 10,437	$ (17,211)	$ 4,263
Property, plant and equipment	$423,884	155,507	579,391	208,073	158,492	366,565	—	945,956
Intangible assets	25,863	7,088	32,951	—	22,318	22,318	—	55,269
Total assets	482,543	176,269	658,812	252,514	188,399	440,913	182,863	1,282,588
Capital expenditures	25,610	13,601	39,211	10,906	10,261	21,167	367	60,745
Acquisition of operating entities	—	—	—	1,253	98,805	100,058	—	100,058

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

	Year ended December 31, 2010							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non regulated energy sales	$ 80,117	$ 49,860	$129,977	$ —	$ —	$ —	$ —	$ 129,977
Waste disposal fees	—	9,039	9,039	—	—	—	—	9,039
Water reclamation and distribution	—	—	—	38,011	—	38,011	—	38,011
Other revenue	2,122	1,209	3,331	—	—	—	—	3,331
Total revenue	82,239	60,108	142,347	38,011	—	38,011	—	180,358
Operating expenses	29,481	43,817	73,298	22,199	—	22,199	—	95,497
	52,758	16,291	69,049	15,812	—	15,812	—	84,861
Depreciation of property, plant and equipment	(17,233)	(11,243)	(28,476)	(7,820)	—	(7,820)	(175)	(36,471)
Amortization of intangible assets	(6,670)	(2,774)	(9,444)	(700)	—	(700)	—	(10,144)
Administration expenses	(4,674)	(1,825)	(6,499)	(1,890)	—	(1,890)	(6,497)	(14,886)
Write down of long-lived assets	(1,836)	(656)	(2,492)	—	—	—	—	(2,492)
Foreign exchange gain	—	—	—	—	—	—	528	528
Interest expense	(7,742)	(770)	(8,512)	(1,911)	—	(1,911)	(14,416)	(24,839)
Interest, dividend and other income	783	633	1,416	149	—	149	3,599	5,164
Acquisition related costs	—	—	—	—	—	—	(3,015)	(3,015)
Loss on derivative financial instruments	(5,486)	—	(5,486)	—	—	—	4,383	(1,103)
Earnings / (loss) before income taxes	9,900	(344)	9,556	3,640	—	3,640	(15,593)	(2,397)
Property, plant and equipment	$412,159	$149,837	$561,996	$199,251	—	$199,251	$ 493	$ 761,740
Intangible assets	28,287	23,104	51,391	22,495	—	22,495	—	73,886
Total assets	467,589	194,906	662,495	237,513	—	237,513	116,941	1,016,949
Capital expenditures	2,331	11,554	13,885	6,644	—	6,644	260	20,789
Acquisition of operating entities	40,281	—	40,281	2,120	1,996	4,116	—	44,397

(in thousands of Canadian dollars except as noted and amounts per share)

21. Segmented Information (continued)

Operational Segments (continued)

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2011 or 2010: Hydro Québec 17% (2010 - 14%), Pacific Gas and Electric 11% (2010 - 10%), Manitoba Hydro 16% (2010 – 15%), and AES 15% (2010 - 18%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

APUC and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2011	2010
Revenue		
Canada	$ 88,900	$ 72,360
United States	187,738	107,998
	$ 276,638	$ 180,358
Property, plant and equipment		
Canada	$ 474,094	$ 464,783
United States	471,862	296,957
	$ 945,956	$ 761,740
Intangible assets		
Canada	$ 25,863	$ 43,305
United States	29,406	30,581
	$ 55,269	$ 73,886
Other assets		
Canada	$ 3,577	$ 1,415
United States	—	1,940
	$ 3,577	$ 3,355

Revenues are attributed to the two countries based on the location of the underlying generating and utility facilities.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments

a) Fair Value of financial instruments

	2011 Carrying amount	2011 Fair Value	2010 Carrying amount	2010 Fair value
Cash and cash equivalents	$ 72,887	$ 72,887	$ 4,749	$ 4,749
Short-term investments	833	833	3,674	3,674
Accounts receivable and due from related parties	46,669	46,669	26,593	26,593
Restricted cash	4,693	4,693	3,564	3,564
Notes receivable	24,534	24,534	18,744	18,744
Total financial assets	$ 149,616	$ 149,616	$ 57,324	$ 57,324
Accounts payable and due to related parties	10,177	10,177	3,716	3,716
Accrued liabilities	47,102	47,102	29,534	29,534
Dividends payable	9,566	9,566	5,719	5,719
Long-term liabilities	332,716	338,264	259,958	262,117
Convertible debentures	122,297	162,195	181,760	216,769
Interest rate swaps	6,975	6,975	5,440	5,440
Energy forward purchase contracts	1,169	1,169	378	378
Foreign exchange contracts	—	—	45	45
Total financial liabilities	$ 530,002	$ 575,448	$ 486,550	$ 523,718

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value at December 31, 2011 and 2010 due to the short-term maturity of these instruments.

Long term investments and notes receivable include equity instruments and notes receivable. The equity instruments do not have a quoted market price in an active market, and fair value cannot be reliably measured. Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities and convertible debentures at fixed interest rates and variable rates. The estimated fair value is calculated using the current interest rates.

Advances in aid of construction have a carrying value of $75,151 (2010 - $55,115) at December 31, 2011. Portions of these non-interest bearing instruments are payable annually through 2026 and amounts not paid by the contract expiration dates become nonrefundable. Their relative fair values cannot be accurately estimated because future refund payments depend on several variables, including new customer connections, customer consumption levels, and future rate increases. However, the fair value of these amounts would be less than their carrying value due to the non-interest bearing feature.

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments (continued)

b) Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2011 are as follows:

	Level 1	Level 2	Level 3	Total
Derivative liabilities:				
Energy forward purchase contracts	$ —	$(1,169)	$ —	$(1,169)
Interest rate swap	—	(6,975)	—	(6,975)
	$ —	$(8,144)	$ —	$(8,144)

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or level 3 during the years ended December 31, 2011 or 2010.

The fair value of derivative instruments is estimated using forward curves obtained from brokers and market participants, net of estimated credit risk.

The Red Lily conversion option (note 5 (a)) is measured at fair value on a recurring basis using unobservable inputs (Level 3).The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, discount rate and estimated cash flows. There was no change in fair value of $0 during the years ended December 31, 2011 or 2010.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments (continued)

c) Effect of derivative instruments on the Consolidated Statement of Operations

Loss/(gain) on derivative financial instruments consist of the following:

	2011	2010
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (45)	$(1,424)
Interest rate swaps	1,536	(2,787)
Energy forward purchase contracts	833	(2,931)
Total change in unrealized loss/(gain) on derivative financial instruments	$2,324	$(7,142)
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ 691	$ (620)
Interest rate swaps	2,138	5,929
Energy forward purchase contracts	691	2,936
Total realized loss on derivative financial instruments	$3,520	$ 8,245
Loss on derivative financial instruments	$5,844	$ 1,103

(d) Risk Management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, short term investments, accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from Power Generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

(in thousands of Canadian dollars except as noted and amounts per share)

22. Financial instruments (continued)

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $4,996 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2011 the Company's exposure to credit risk for these financial instruments was as follows:

	December 31, 2011	
	Canadian $	US $
Cash and cash equivalents and restricted cash	$ 69,108	$ 9,149
Short term investments	833	—
Accounts receivable	14,229	29,912
Allowance for Doubtful Accounts	—	(251)
Note Receivable	22,478	2,021
	$ 106,648	$40,831

There are no material past due amounts in accounts receivable.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2011, in addition to cash on hand of $72,887 the Company had $80,400 available to be drawn on its senior debt facility. The senior credit facility contains covenants which may limit amounts available to be drawn. The Company's liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long term debt obligations	$ 1,624	$ 3,725	$ 9,556	$ 317,811	$ 332,716
Convertible Debentures	59,726	—	—	62,571	122,297
Interest on long term debt	25,571	40,241	37,250	124,807	227,869
Accounts Payable and due to related parties	10,177	—	—	—	10,177
Accrued liabilities	47,102	—	—	—	47,102
Derivative financial instruments:					
Interest Rate Swaps	2,935	4,113	1,096	—	8,144
Capital Lease Payments	231	260	10	—	501
Other obligations	1,063	516	516	7,681	9,776
Total obligations	$ 148,429	$48,855	$48,428	$ 512,870	$ 758,582

22. Financial instruments (continued)

Foreign Currency Risk

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

At December 31, 2011, the Company had no outstanding forward foreign exchange contracts. As at December 31, 2010, APUC had outstanding foreign exchange forward contracts to sell US$3,000 at an average rate of $1.00 and having a fair value liability of $45.

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

In connection with the project debt at the St. Leon facility which was repaid during 2011, APCo previously entered into an interest rate swap to hedge the floating interest rate on the project debt. Under the terms of the swap, the Company pays a fixed interest rate of 4.47% on a notional amount of $67.8 million and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2011, the estimated fair value of the interest rate swap was a liability of $6,975 (2010 –liability of $5,440). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

Market Risk

APUC provides energy requirements to various customers under contract at fixed rates. While the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In January 2011, APUC entered into electricity derivative contracts with Nextera (“counterparty”) for a term ending February 2014, which are net settled fixed-for-floating swaps whereby APUC will pay a fixed price and receive the floating or indexed price on a notional quantity of 162,128 MW-hrs of energy over the remainder of the contact term at an average rate of approximately $51.40 per MW-hr. The estimated fair value of these forward energy hedge contracts at December 31, 2011 was a net liability of $1,169 (December 31, 2010 - $nil).

23. Capital disclosures

The Company views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

The Company's objectives when managing capital are:

- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital.
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets.
- To ensure generation of cash is sufficient to fund sustainable distributions to Unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

The Company monitors its cash position on a regular basis to ensure funds are available to meet current operating as well as capital expenditures. In addition, the Company regularly reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

24. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

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Section 4: EX-99.3 (MANAGEMENT'S DISCUSSION AND ANALYSIS)

Exhibit 99.3

ALGONQUIN
Power & Utilities Corp.

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per share and convertible debenture amounts or where otherwise noted)

Management of Algonquin Power & Utilities Corp. ("APUC") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2011. This Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2011 and 2010 prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). See *Change in Accounting Policies* for a discussion on the reasons for this change. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 18, 2012.

Caution concerning forward-looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy; and the state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") and "per share cash provided by operating activities" are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" can be found throughout this MD&A.

Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Overview and Business Strategy

APUC is incorporated under the Canada Business Corporations Act. APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the independent power and rate regulated utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through dividend growth supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon APUC strives to deliver annualized per share earnings growth of more than 5% and continued growth in its dividend supported by these increasing cash flows, earnings and additional investment prospects

APUC's current quarterly dividend to shareholders is $0.07 per share or $0.28 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Additional increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") and dividend levels shall be reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC currently conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of renewable energy assets and Liberty Utilities Co. ("Liberty Utilities") which owns and operates a portfolio of North American rate regulated utilities.

Algonquin Power Co.

APCo generates and sells electrical energy through a diverse portfolio of renewable power generation and clean thermal power generation facilities across North America. APCo seeks to deliver continuing growth through development of greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of expansion opportunities within APCo's existing portfolio of independent power facilities. As at December 31, 2011, APCo owns or has interests in hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds exchangeable debt securities in a 26 MW wind powered generating station completed in early 2011 in Saskatchewan. All of the electrical output from the wind energy facilities are sold pursuant to long term power purchase agreements ("PPAs") with major utilities which have a weighted average remaining contract life of 20 years. Approximately 80% of the electrical output from the hydroelectric facilities is sold pursuant to long term PPAs with major utilities which have a weighted average remaining contract life of 8.5 years.

APCo owns thermal energy facilities with approximately 120 MW of installed generating capacity and holds ownership interests in three facilities having gross installed capacity of approximately 200 MW. Approximately 67% of the electrical output from the owned thermal facilities is sold pursuant to long term PPAs with major utilities and which have a weighted average remaining contract life of 11 years.

Liberty Utilities Co.

Liberty Utilities provides rate regulated electricity, natural gas and, water distribution and wastewater collection utility services. Liberty Utilities' underlying business strategy is to be a leading provider of safe, high quality and reliable utility services through a nationwide portfolio of moderate sized utilities and deliver stable and predictable earnings to APUC from these utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings through acquisition opportunities which accretively expand its utility business portfolio. The utility businesses owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. As a result of the current and expected growth of Liberty Utilities, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. As a result of this decision, Liberty Utilities businesses operate under two separately managed regions - Liberty Utilities (South) and Liberty Utilities (West).

Liberty Utilities (South) operates in the states of Arizona, Texas, Missouri and Illinois and currently provides regulated water and wastewater utility services to approximately 76,000 customers in those states.

Liberty Utilities (West) operates in the state of California and currently provides regulated local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region of California; on January 1, 2011, in partnership with Emera Inc. ("Emera"), Liberty Utilities (West) acquired the California-based electricity distribution utility and related generation assets (the "California Utility") from NV Energy.

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed to initially deliver electrical and natural gas distribution services to 126,000 customers to be acquired through the acquisition of Granite State Electric Company ("Granite State") and EnergyNorth Natural Gas, Inc., ("EnergyNorth"). Liberty Utilities (Central) will be created initially to manage the delivery of Liberty Utilities gas distribution services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from ATMOS Energy Corporation ("Atmos").

Major Highlights

Corporate Highlights

Dividend Increased to $0.28 for each Common Share

On March 3, 2011, the Board approved an increase in the dividend from $0.24 to $0.26 on an annualized basis. On August 11, 2011, the Board approved a further dividend increase of $0.02 bringing the total dividend to $0.28, paid quarterly at the rate of $0.07 per common share. In approving the increase in dividends, the Board considered the continuing contributions of growth initiatives that began in 2010 and the significant progress made with regards to implementing additional growth initiatives announced in 2011 that have raised the growth profile for APUC's earnings and cash flows. These new growth initiatives, discussed in more detail below, include the acquisition of additional natural gas and electric utilities as well as new wind power generating projects to be built over the next several years.

APUC believes that the increase in dividend is consistent with its stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

Strengthened Liquidity – Issuance of $95.3 million of Common Shares

On October 27, 2011, APUC completed a public offering (the "Offering") of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

The net proceeds of the Offering will be used to fund a portion of the investment related to previously announced growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

Strengthened Balance Sheet – Conversion of Convertible Debentures to Equity

Effective May 16, 2011 ("Redemption Date"), APUC redeemed $2.1 million, all of the remaining issued and outstanding, Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 ("Series 1A Debentures") and issued 430,666 share of APUC. Between January 1, 2011 and the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,976 shares of APUC.

Effective February 24, 2012 ("Series 2A Redemption Date"), APUC redeemed $57.0 million, representing the remaining issued and outstanding, Series 2A Debentures by issuing and delivering 9,836,520 APUC shares. Between January 1, 2012 and the Series 2A Redemption Date, a principal amount of $2.9 million of Series 2A Debentures were converted into 485,998 shares of APUC.

Strategic Investment Agreement with Emera

On April 29, 2011, APUC entered into a strategic investment agreement (the "Strategic Agreement") with Emera which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Agreement builds on the strategic partnership effectively established between the two companies in April 2009.

The Strategic Agreement outlines "areas of pursuit" for each of APUC and Emera. For APUC, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. For Emera, these include investment opportunities related to regulated renewable projects within its service territories and large electric utilities. These "areas of pursuit" are intended to represent investment areas in which there is potential overlap between Algonquin and Emera and are not exhaustive of either company's business focus and do not limit in any way the activities which either APUC or Emera can undertake. Each of APUC or Emera are free to undertake independently investments within their own "area of pursuit" and outside the other party's "areas of pursuit". Under the Strategic Agreement, to the extent either APUC or Emera encounter opportunities which fall within the other's "areas of pursuit", they are committed to work with the other party in the development of such investment opportunities.

As an element of the Strategic Agreement, Emera's allowed common equity interest in APUC will be increased from 15% to 25%. The Strategic Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

Liberty Utilities Highlights

California Utility Acquisition and Senior Debt Financing

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, California Pacific Electric Company ("Calpeco").

Filing of Approval Application for 100% of California Utility

On April 29, 2011, Emera agreed to sell its 49.999% direct ownership in the California Utility to Liberty Utilities, with closing of such transaction subject to regulatory approval. As consideration, Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012) and the balance of the shares will be issued following completion of the California Utility's first rate case, expected to be completed in early 2013.

New Hampshire Utility Acquisitions

On December 9th, 2010 Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company ("Granite State"), a regulated electric distribution utility in New Hampshire, and EnergyNorth Natural Gas, Inc. ("EnergyNorth"), a regulated natural gas distribution utility in New Hampshire, both from National Grid USA ("National Grid"), for total consideration of U.S. $285.0 million plus certain working capital adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $250 million.

The closing of the transaction is subject to approval by the New Hampshire Public Utilities Commission ("NHPUC"). Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

Midwest Utility Acquisitions

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the "Midwest Gas Utilities") located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million.

The closing of the transaction is subject to approval by the Missouri Public Service Commission ("MPSC"), Iowa Utilities Board ("IUB"), and Illinois Commerce Commission ("ICC"). Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Liberty Utilities Credit Facility

On January 19, 2012, Liberty Utilities entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility can be increased to accommodate future working capital needs or other requirements.

Algonquin Power Co. Highlights

Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind power projects in the United States (the "Projects") from Gamesa Corporación Tecnológica, S.A. ("Gamesa"). APCo will contribute U.S. $269 million to partially fund the acquisition of the Projects; tax assisted equity investors will contribute U.S. $360 million. APCo intends to finance its investment with approximately 45% debt and 55% equity. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissioning near the end of 2012.

The Projects consist of four facilities, Minonk (200MW), Senate (150MW), Pocahontas Prairie (80MW) and Sandy Ridge (50MW) located in the states of Illinois, Texas, Iowa and Pennsylvania, respectively. Pocahontas Prairie and Sandy Ridge have recently reached their commercial operation dates ("COD") in February 2012, and Senate and Minonk are in construction with COD anticipated in Q4 2012. Total annual energy production from the four facilities is expected to be 1,644 GW-hrs per year. The Projects are comprised of 240 Gamesa G9X-2.0 MW wind turbines. The Projects each have entered into a 20 year contract with Gamesa to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities.

The Projects have long term, fixed price power sales contracts (the "Power Sales Contracts") with a weighted average life of 11.8 years (Minonk and Sandy Ridge 10 years, Senate 15 years). Approximately 73% of energy revenues would be earned under the Power Sales Contracts. All energy produced in excess of that sold under the Power Sales Contracts, together with ancillary services including capacity and renewable energy credits, will be sold into the energy markets in which the facilities are located.

St. Leon Facility Expansion

On July 18, 2011, APCo entered into a 25-year power purchase agreement with Manitoba Hydro in respect of a 16.5 MW expansion ("St. Leon II") of its existing St. Leon wind energy project located in the Province of Manitoba.

Construction of this project commenced on August 30, 2011. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The total capital cost of the project is expected to be $29.5 million. The project is expected to achieve commercial operation early in the second quarter of 2012 with revenues in the first full year of operating following commissioning expected to be $3.8 million.

Red Lily Wind Project

On February 28, 2011 the 26.4 MW wind generation facility in southeastern Saskatchewan ("Red Lily I") commenced commercial operation under the PPA. APUC's investment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011. APUC earned $1.6 million in interest income and $1.9 million in other payments and fees in 2011. APUC has the option to formally exchange its debt investment for a 75% equity position in the facility in 2016.

New Projects Under Development

As of March 18, 2012, APCo had been awarded or acquired interests in seven major power development projects that significantly expands the company's electrical generation capacity by 350 MW and once completed will increase the company's annual generation production by over 1,200 GWhrs. Each project has a power purchase agreement with a Canadian provincial utility and has a contract length of 20 years or longer.

The following summarizes a number of projects under development and for which PPA's have been awarded since December 2010.

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind	Saskatchewan	177	$ 355.0	2016	25	720.0
Amherst Island	Ontario	75	$ 230.0	2014	25	247.0
Morse Wind [1]	Saskatchewan	25	$ 70.0	2014	20	93.0
St. Damase	Quebec	24	$ 70.0	2013	20	86.0
Val Eo	Quebec	24	$ 70.0	2015	20	66.0
St. Leon II	Manitoba	17	$ 30.0	2012	25	58.0
Cornwall Solar	Ontario	10	$ 45.0	2013	20	13.4
Total		**352**	**$ 870.0**			**1,283.4**

[1] The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011.

A more detailed discussion of these projects is presented within the *APCo: Development Division* business unit analysis.

Senior Unsecured Debentures

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the "Senior Unsecured Debentures"). The net proceeds from the Senior Unsecured Debentures were used to repay the outstanding senior project debt financing related to the St. Leon facility (the "AirSource Senior Debt") and to reduce amounts outstanding under APCo's senior revolving credit facility (the "Facility"). The Senior Unsecured Debentures mature on July 25, 2018, and bear interest at a rate of 5.50% per annum, calculated semi-annually payable on January 25 and July 25 each year, commencing on January 25, 2012.

Credit Facility Renewal

On February 14, 2011 APCo renewed the Facility with its bank syndicate for a three year term with a maturity date of February 14, 2014. The committed credit under the Facility is $120 million.

2011 Annual results from operations

APUC continued to show strong results through 2011. Over the past two years, APUC has focused its efforts on a number of value creation initiatives that, through their completion, are now contributing to the growth evident in APUC revenues, adjusted EBITDA and net earnings. These initiatives include Liberty Utilities' acquisition of the California Utility and successful prosecution of rate cases, APCo's refurbishment of the Energy from Waste facility, acquisition of the Tinker Hydro facility and completion of construction and commissioning of the Red Lily I Wind Farm. As a result, for the year ended December 31, 2011, APUC reported total revenue of $276.6 million as compared to $180.4 million during the same period in 2010, an increase of $96.2 million or 53%.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. (see Non-GAAP Performance Measures). For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million.

Key Selected Annual Financial Information

	Year ended December 31		
	2011 (millions)	**2010 (millions)**	**2009[5] (millions)**
Revenue	**$ 276.6**	$ 180.4	$ 187.3
Adjusted EBITDA [1, 3]	**$ 105.2**	$ 75.1	$ 79.4
Cash provided by Operating Activities	**69.7**	41.4	48.0
Net earnings attributable to Shareholders	**23.4**	18.0	31.3
Adjusted net earnings [1, 3]	**41.6**	22.5	30.5
Dividend declared to Shareholders	**32.4**	22.8	19.3
Per share			
Basic net earnings	**$ 0.20**	$ 0.19	$ 0.39
Adjusted net earnings [1, 3]	**$ 0.36**	$ 0.24	$ 0.38
Diluted net earnings	**$ 0.20**	$ 0.19	$ 0.39
Cash provided by Operating Activities [2, 3]	**$ 0.60**	$ 0.44	$ 0.60
Dividends declared to Shareholders	**$ 0.27**	$ 0.24	$ 0.24
Total Assets	**1,282.6**	1,016.9	1,013.4
Long Term Liabilities[4]	**332.7**	260.0	241.4

1 APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.
2 APUC uses per share cash provided by operating activities to enhance assessment and understanding of the performance of APUC.
3 Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
4 Includes Long-term liabilities and Current portion of long-term liabilities.
5 Presented using Canadian Generally Accepted Accounting Principles.

The major factors resulting in the increase in APUC revenue in the year ended December 31, 2011 as compared to the corresponding period in 2010, are set out as follows:

	Year ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 180.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	78.1
Liberty Utilities (South) revenue increases primarily due to rate case approvals	8.8
Energy-from-Waste facility	7.6
Effect of hydrology resource compared to comparable period in prior year	6.8
Effect of wind resource compared to comparable period in prior year	3.0
Impact of the weaker U.S. dollar	(5.4)
Tinker Hydro/ Algonquin Energy Services (“AES”)	(1.4)
Windsor Locks	(0.9)
All Other	(0.4)
Current Period Revenue	$ 276.6

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the year ended December 31, 2011, APUC experienced an average U.S. exchange rate to each Canadian dollar of approximately U.S. $0.989 as compared to U.S. $1.031 in the same period in 2010. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC’s U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC’s reporting currency.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities’ acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved average hydrology and wind resources in APCo’s Renewable Energy division and improved results from the EFW facility. This increase was partially offset by lower results at Windsor Locks and Tinker facilities, as well as the impact of the weaker U.S. dollar as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million. Basic net earnings per share totalled $0.20 for the year ended December 31, 2011, as compared to $0.19 during the same period in 2010.

For the year ended December 31, 2011, net earnings totalled $27.3 million as compared to $18.4 million during the same period in 2010, an increase of $8.9 million. A number of factors resulted in increased net earnings, including an increase of $32.2 million due to increased earnings from operating facilities, $0.5 million in increased interest and dividend income, $2.2 million related to increased recoveries of income tax expense (see - *2011 Annual Corporate and Other Expenses*) and $0.8 million due to decreased amortization and depreciation expense. These items were partially offset by increased management and administration expenses of $2.6 million, $5.6 million due to increased interest expense, $14.0 million due write downs of intangibles and property, plant and equipment (see - *2011 Annual Corporate and Other Expenses*) and $4.7 million due to increased losses on derivative financial instruments as compared to the same period in 2010.

During the year ended December 31, 2011, cash provided by operating activities totalled $69.7 million or $0.60 per share as compared to cash provided by operating activities of $41.4 million, or $0.44 per share during the same period in 2010, an increase of approximately 36% per share. Cash per share provided by operating activities is a non-GAAP measure. Cash provided by operating activities exceeded dividends declared by 2.1 times during the year ended December 31, 2011 as compared to 1.8 times dividends paid during the same period in 2010. The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2011, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2010.

2011 Fourth quarter results from operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31	
	2011 (millions)	**2010 (millions)**
Revenue	**$ 72.1**	$ 48.4
Adjusted EBITDA [1, 3]	**$ 24.3**	$ 20.8
Cash provided by Operating Activities	**4.6**	15.1
Net earnings (loss) attributable to Shareholders	**(8.5)**	15.6
Adjusted net earnings[1, 3]	**6.7**	18.2
Dividends declared to Shareholders	**9.5**	5.7
Per share		
Basic net earnings (loss)	**$ (0.07)**	$ 0.17
Adjusted net earnings[1, 3]	**$ 0.05**	$ 0.19
Diluted net earnings (loss)	**$ (0.07)**	$ 0.17
Cash provided by Operating Activities [2, 3]	**$ 0.03**	$ 0.17
Dividends declared to Shareholders	**$ 0.07**	$ 0.06

1 APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.

2 APUC uses per share cash from operating activities to enhance assessment and understanding of the performance of APUC.

3 Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

For the three months ended December 31, 2011, APUC reported total revenue of $72.1 million as compared to $48.4 million during the same period in 2010, an increase of $23.7 million or 49%. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2011 as compared to the corresponding period in 2010 are set out as follows:

	Three months ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 48.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	20.8
Liberty Utilities (South) revenue increases primarily due to rate case approvals	1.4
Effect of wind resource compared to comparable period in prior year	1.6
Windsor Locks	(0.9)
Impact of the stronger U.S. dollar	0.7
Other	0.1
Current Period Revenue	$ 72.1

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the three months ended December 31, 2011, APUC experienced an average U.S. exchange rate for each Canadian dollar of approximately U.S. $1.023 as compared to U.S. $1.013 in the same period in 2010. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended December 31, 2011 totalled $24.3 million as compared to $20.8 million during the same period in 2010, an increase of $3.5 million or 17%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved wind resource in APCo's Renewable Energy and the impact of the stronger U.S. dollar. This increase was partially offset by lower results at Windsor Locks as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2011, net loss attributable to Shareholders totalled $8.5 million as compared to net earnings of $15.6 million during the same period in 2010, a decrease of $24.2 million. Net loss per share totalled ($0.07) for the three months ended December 31, 2011, as compared to net earnings of $0.17 during the same period in 2010.

For the three months ended December 31, 2011, net loss totalled $8.1 million as compared to net earnings of $15.8 million during the same period in 2010, a decrease of $23.9 million. A number of factors resulted in decreased net earnings for the three months ended December 31, 2011, including $0.5 million related to increased loss on foreign exchange, $1.1 million due to increased interest expense, $9.8 million related to lower recoveries of income tax expense (see *Fourth Quarter Corporate and Other Expenses)*, $14.0 million due to write downs of intangibles and property, plant and equipment (see - *Fourth Quarter Corporate and Other Expenses*) and $3.4 million due to increased losses on derivative financial instruments as compared to the same period in 2010. These items were partially offset by an increase of $2.9 million due to increased earnings from operating facilities, a decrease of $0.3 million due to reduced depreciation and amortization expense, a decrease of $0.3 million due to reduced management and administration expense and a decrease of $1.2 million due to reduced acquisition costs as compared to the same period in 2010.

During the three months ended December 31, 2011, cash provided by operating activities totalled $4.6 million or $0.04 per share as compared to cash provided by operating activities of $15.1 million, or $0.16 per share during the same period in 2010. Cash per share provided by operating activities is a non-GAAP measure. The change in cash provided by operating activities after changes in working capital in the three months ended December 31, 2011, is primarily due to a modest increase in cash from operations, offset by increased interest expense and reduced tax recoveries as compared to the same period in 2010.

Outlook

APCo

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

APCo's energy services business, AES, anticipates that, based on the expected load forecast for its existing contracts, the APCo owned assets will provide almost 50% of the energy required to service its customers in the first quarter of 2012.

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the Independent System Operator New England ("ISO NE") day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

The EFW facility "tip or pay" waste supply agreement with the Region of Peel (the "Region") expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility. For additional information, see *APCo Divisional Outlook - Thermal Energy*.

On January 27, 2012, APCo announced that it plans not to proceed with the previously announced U.S. $83 million minority investment in First Wind Holdings, LLC's ("First Wind") wind energy facilities portfolio in the North East United States. The longer than anticipated regulatory process in Maine and the number of new acquisition and development opportunities announced since April 2011 contributed to the decision not to proceed with the investment.

Liberty Utilities

Liberty Utilities (South) expects continuing modest customer growth throughout its service territories in 2012.

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011.

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the California Public Utilities Commission ("CPUC") seeking, among other things, an increase of 10.0%, or $7.5 million in general rates. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

Algonquin

APCo: Renewable Energy

	Three months ended December 31			Year ended December 31		
	Long Term Average Resource	2011	2010	Long Term Average Resource	2011	2010
Performance (GW-hrs sold)						
Quebec Region	**73.6**	**79.3**	84.1	**279.3**	**304.4**	275.9
Ontario Region	**32.1**	**28.2**	20.2	**134.6**	**121.1**	90.2
Manitoba Region	**105.0**	**119.7**	97.2	**372.0**	**383.8**	343.1
Saskatchewan Region*	**23.3**	**27.7**	—	**66.7**	**68.0**	—
New England Region	**13.4**	**23.7**	13.4	**58.8**	**70.2**	47.9
New York Region	**23.8**	**22.4**	24.4	**90.4**	**92.6**	79.6
Western Region	**12.7**	**11.8**	10.5	**65.9**	**65.5**	59.1
Maritime Region	**35.0**	**40.2**	55.5	**136.9**	**183.0**	148.6
Total	**318.9**	**353.0**	305.3	**1,204.6**	**1,288.6**	1,044.4
Revenue**						
Energy sales		**$ 23,816**	$ 21,867		**$ 87,566**	$ 80,117
Less:						
Cost of Sales – Energy***		**(737)**	(431)		**(3,762)**	(5,047)
Net Energy Sales		**$ 23,079**	$ 21,436		**$ 83,804**	$ 75,070
Other Revenue		**317**	563		**2,291**	2,122
Total Net Revenue		**$ 23,396**	$ 21,999		**$ 86,095**	$ 77,192
Expenses						
Operating expenses		**(7,933)**	(7,013)		**(26,116)**	(24,434)
Interest and Other income		**613**	151		**2,143**	783
Division operating profit (including other income)		**$ 16,076**	$ 15,137		**$ 62,122**	$ 53,541

* Actual production in the Saskatchewan Region reflects production since Red Lily I achieved commercial operation on February 23, 2011. APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility and has an option to acquire a 75% equity interest in the facility in 2016. The long term average resource reflects three and twelve months of production.

** While most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

*** Cost of Sales - Energy consists of energy purchases by AES which is resold to its retail and industrial customers. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

2011 Annual Operating Results

For the year ended December 31, 2011, the Renewable Energy division produced 1,288.6 GWhrs of electricity, as compared to 1,044.4 GWhrs produced in the comparable period, an increase of 23%. The increased generation is primarily due to strong average hydrology in the year as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 72,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 710,000 tons of CO_2 gas was prevented from entering the atmosphere in the year ended December 31, 2011.

During the year ended December 31, 2011, the division generated electricity equal to 107% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the year ended December 31, 2011, the Quebec, New England and Maritimes regions experienced resources significantly higher than long-term averages, producing 9%, 19%, and 34%, respectively, above long-term average resources, while the Manitoba, Saskatchewan, and New York regions experienced resources slightly higher than long-term averages, producing between 2 - 3% above long-term average resources. The Western region experienced resources at long-term averages while the Ontario region experienced resources 10% below long-term averages.

For the year ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $87.6 million, as compared to $80.1 million during the same period in 2010, an increase of $7.5 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the year ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $83.8 million, as compared to $75.1 million during the same period in 2010, an increase of $8.7 million or 12%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $4.8 million due to a 15% overall increase in hydrology and $1.1 million due to an increase in weighted average energy rates, primarily in the Quebec region, of approximately 3% as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $1.8 million due to increased average hydrology partially offset by $1.1 million due to a decrease in weighted average energy rates of approximately 15%. Revenue from the Manitoba region increased $2.7 million primarily due to a stronger wind resource and $0.4 million due to an increase in weighted average energy rates. Revenue in the Maritime region increased $0.5 million, primarily due to increased customer demand as compared to the same period in 2010. These increases were partially offset by a $1.4 million decrease in revenue at AES primarily due to decreased energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($11.6 million) and merchant sales of production in excess of customer demand and other revenue ($2.3 million). The division reported decreased revenue of $1.0 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

Red Lily I achieved commercial operations effective February 23, 2011. From the commercial operation date through December 31, 2011 Red Lily I produced 68.0 GWhrs of electricity. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily for a direct 75% equity interest in 2016. For the year ended December 31, 2011, APCo earned fees and interest payments from Red Lily I in the total amount of $3.5 million.

For the year ended December 31, 2011, energy purchase costs by AES totalled $3.8 million. During this same period, AES purchased approximately 45.5 GWhrs of energy at market and fixed rates averaging U.S. $84 per MWhr. The Maritime region generated approximately 80% of the load required to service its customers as well as AES' customers in the year ended December 31, 2011. The division reported decreased energy purchase costs of $0.2 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses excluding energy purchases totalled $26.1 million, as compared to $24.4 million during the same period in 2010, an increase of $1.7 million or 7%. Operating expenses were impacted by $0.9 million related to increased operating costs associated with the Tinker Assets and AES, primarily the result of higher production levels in the Maritime region as compared to the same period in 2010. These increases were partially offset by reduced operating expenses of approximately $0.6 million at the hydroelectric facilities. Operating expenses include costs incurred in the period of $1.9 million associated with the pursuit of various growth and development activities, an increase of $0.7 million as compared to the same period in 2010. In the prior period, APCo recorded a reduction in the development costs due to a reimbursement of $0.9 million in connection with the Red Lily I wind project. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, interest and other income totalled $2.1 million, as compared to $0.8 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the year ended December 31, 2011, Renewable Energy's operating profit totalled $62.1 million, as compared to $53.5 million during the same period of 2010, representing an increase of $8.6 million or 16%. For the year ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to increased hydrology and wind resources in the Canadian regions.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, the Renewable Energy division produced 353.5 GWhrs of electricity, as compared to 305.3 GWhrs produced in the same period in 2010, an increase of 16%. The increased generation is due to improved average wind generation in the quarter as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 79,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 194,000 tons of CO_2 gas was prevented from entering the atmosphere in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the division generated electricity equal to 111% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the fourth quarter of 2011, the New England region experienced resources significantly higher than long-term averages, producing 175% above long-term average resources, while the Manitoba, Saskatchewan, and Maritimes regions experienced resources higher than long-term averages, producing between 15 - 20% above long-term average resources. The Quebec region experienced resources above long-term averages, producing approximately 10% above long-term average resources. The Ontario, Western and New York regions experienced resources between 5 - 10% below long-term averages.

For the quarter ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $23.8 million, as compared to $21.9 million during the same period in 2010, an increase of $1.9 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $23.1 million, as compared to $21.4 million during the same period in 2010, an increase of $1.7 million or 8%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $0.5 million primarily due to a combination of an increase in weighted average energy rates of approximately 1% and a 5% overall increase in hydrology, primarily in the Ontario region as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $0.6 million primarily due to an increase of approximately 35% in average hydrology, offset by $0.6 million due to a decrease in weighted average energy rates of approximately 30% as compared to the same period in 2010. Revenue in the Maritime region decreased $0.3 million, primarily due to lower merchant sales of excess energy as compared to the same period in 2010. AES experienced a $0.2 million increase in revenue primarily due to increased average energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($2.3 million) and merchant sales of production in excess of customer demand and other revenue ($0.9 million). Revenue from the Manitoba region increased $1.5 million due to an increased wind resource and $0.2 million due to an increase in weighted average energy rates as compared to the same period in 2010. The division reported decreased revenue of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

In the quarter ended December 31, 2011 Red Lily I produced 27.7 GWhr of electricity which was sold to SaskPower. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. For the three months ended December 31, 2011, APCo earned fees and interest payments from Red Lily in the total amount of $0.7 million.

For the quarter ended December 31, 2011, energy purchase costs by AES totalled $0.7 million as compared to $0.4 million during the same period in 2010. During the quarter, AES purchased approximately 13.1 GWhr of energy at market and fixed rates averaging U.S. $54 per MWhr. The Maritime region generated approximately 70% of the load required to service its customers as well as AES's customers in the three months ended December 31, 2011.

For the quarter ended December 31, 2011, operating expenses excluding energy purchases totalled $7.9 million, as compared to $7.0 million during the same period in 2010, an increase of $0.9 million or 13%. Operating expenses were impacted by a $0.3 million increase in operating costs at Canadian hydroelectric facilities, primarily resulting from increased variable operating costs tied to higher production, partially offset by a decrease of $0.3 million related to decreased operating costs associated with the Tinker Assets as compared to the same period in 2010. Operating expenses include costs incurred in the period of $1.2 million associated with the pursuit of various growth and development activities, an increase of $0.5 million as compared to the same period in 2010. The division reported decreased expenses of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest and other income totalled $0.6 million, as compared to $0.2 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the quarter ended December 31, 2011, Renewable Energy's operating profit totalled $16.1 million, as compared to $15.1 million during the same period of 2010, representing an increase of $1.0 million or 7%. For the quarter ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to stronger hydrology and wind generation in both the U.S. and Canadian regions.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

AES anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 35,000 MWhrs of energy to its customers in the first quarter of 2012. AES anticipates that APCo owned assets will provide 43% of the energy required to service its customers in the first quarter of 2012 and that it will need to purchase approximately 20,000 MWhrs of energy from the ISO NE or similar market. AES has in place fixed price financial energy contracts to operationally hedge the price of the customer supply obligations which are not expected to be supplied by APCo owned assets and to minimize the volatility of the energy prices. These contracts in combination with the expected production from APCo owned assets are used to balance the monthly customer load.

APCo: Thermal Energy Division

	Three months ended December 31		Year ended	December 31
	2011	2010	2011	2010
Performance (GW-hrs sold)	**126.5**	120.6	**517.0**	465.4
Performance (tonnes of waste processed)	**42,145.0**	43,535.0	**166,825.0**	90,690.0
Performance (steam sales – billions lbs)	**308.4**	315.6	**1,209.4**	1,180.0
Revenue				
Energy/steam sales	**$ 10,582**	$ 11,506	**$ 46,666**	$ 49,860
Less:				
Cost of Sales – Fuel *	**(5,694)**	(5,492)	**(22,896)**	(22,348)
Net Energy/steam Sales Revenue	**$ 4,888**	$ 6,014	**$ 23,770**	$ 27,512
Waste disposal sales	**4,046**	4,164	**16,406**	9,039
Other revenue	**541**	311	**1,352**	1,209
Total net revenue	**$ 9,475**	$ 10,489	**$ 41,528**	$ 37,760
Expenses				
Operating expenses *	**(5,449)**	(5,492)	**(21,589)**	(21,469)
Interest and other income	**(74)**	100	**(6)**	633
Division operating profit				
(including interest and dividend income)	**$ 3,952**	$ 5,097	**$ 19,933**	$ 16,924

* Cost of Sales - Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

2011 Annual Operating Results

For the year ended December 31, 2011, the Thermal Energy Division produced 517.0 GW-hrs of energy as compared to 465.4 GW-hrs of energy in the comparable period of 2010. During the year ended December 31, 2011, the business unit's total production increased by 52.4 GWhr from the Windsor Locks facility and 6.1 GWhr from the EFW facility as compared to the same period in 2010. The comparable period includes 2.5 GWhr of production from landfill gas facilities which ceased generating energy and were closed in 2010.

The EFW facility processed 166,825 tonnes of municipal solid waste in 2011 as compared to 90,690 tonnes processed in the same period of 2010. The EFW facility processed waste for a full 12 month period in 2011 as compared to a 6 month period in 2010 when from January to July 2010 the facility was shut down as it underwent an extensive refurbishment. The current level of production resulted in the diversion of approximately 120,000 tonnes of waste from municipal solid waste landfill sites in the year ended December 31, 2011.

During the year ended December 31, 2011, the BCI and Windsor Locks facilities sold approximately 1,200 billion lbs of steam as compared to approximately 1,200 billion lbs of steam in the comparable period of 2010. During the year ended December 31, 2011, operations at the EFW facility generated 508 billion lbs of steam for the BCI facility as compared to 272 billion lbs of steam in the same period in 2010.

For the year ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $46.7 million, as compared to $49.9 million during the same period in 2010, a decrease of $3.2 million, or 6%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $23.8 million, as compared to $27.5 million during the same period in 2010, a decrease of $3.7 million, primarily arising from the weaker U.S. dollar and the power purchase agreement that concluded in April 2010 at the Windsor Locks facility.

The overall decrease in revenue from energy / steam sales was primarily due to a decrease of $5.7 million at the Windsor Locks facility as a result of decreased average energy rates, in part due to the change in operating model of the facility as it came off contract, partially offset by an increase of $4.8 million as a result of increased production, as compared to the prior year. The Sanger facility experienced a net decrease of $0.6 million as a result of decreased energy pricing, in part due to lower average landed price per mmbtu for natural gas, partially offset by $0.2 million as a result of increased production. Energy / steam sales revenue decreased $0.3 million in the period as a result of the closure of the LFG facilities, as compared to the prior year. The decrease in revenue was partially offset by $0.3 million at the BCI and EFW facilities as a result of increased production of energy and steam, as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $1.7 million from operations as a result of the weaker U.S. dollar, as compared to the same period in 2010.

Revenue from waste disposal sales for the year ended December 31, 2011 totalled $16.4 million, as compared to $9.0 million during the same period in 2010. The increase was a result of the EFW facility refurbishment from January to July 2010 in the comparable period of 2010.

For the year ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $22.9 million, as compared with $22.3 million in the same period in 2010, an increase of $0.5 million. 1 The overall natural gas expense at the Windsor Locks facility increased U.S. $1.7 million (10%), primarily the result of a 10% increase in volume of natural gas consumed, as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the year was U.S. $4.84 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of U.S. $0.3 million (5%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the year was U.S. $4.42 per mmbtu. The division reported decreased fuel expenses of $0.8 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $21.6 million, as compared to $21.5 million during the same period in 2010, an increase of $0.1 million. The increase in operating expenses in the year was primarily due to $4.4 million in increased gas, consumables, repair and maintenance and wages at the EFW facility resulting from the outage at the facility in 2010, partially offset by $0.6 million in reduced operating costs at Windsor Locks, $2.0 million at BCI, primarily

[1] APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. Consequently the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other showing decreasing costs, as compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each mmbtu. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed per unit cost for natural gas combined with a consumption of a higher volume of such gas.

the result of reduced natural gas costs due to the EFW facility generating more steam and $0.7 million of reduced operating costs as a result of the closure of the land-fill gas facilities in 2010, as compared to the same period in 2010. Operating expenses in the included costs of $0.4 million associated with the pursuit of various growth and development activities as compared to $0.5 million in the comparable period. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, the Thermal Energy division's operating profit totalled $19.9 million, as compared to $16.9 million during the same period in 2010, representing an increase of $3.0 million or 18%. Operating profit in the Thermal Energy division exceeded expectations for the year ended December 31, 2011 as a result of improved operations at the EFW facility.

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, the business unit produced 126.5 GWhr of energy as compared to 120.6 GWhr of energy in the comparable period of 2010. During the quarter ended December 31, 2011, the business unit's total production increased by 8.0 GWhr from the Windsor Locks facility, partially offset by a decline of 1.6 GWhr from the Sanger facility, as compared to the same period in 2010.

The EFW facility processed 42,145 tonnes of municipal solid waste as compared to 43,535 tonnes of municipal solid waste in the same period of 2010. The current level of production resulted in the diversion of approximately 30,400 tonnes of waste from municipal solid waste landfill sites in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the BCI and Windsor Locks facilities sold 310 billion lbs of steam as compared to 320 billion lbs of steam in the comparable period of 2010. During the quarter ended December 31, 2011, operations at the EFW facility generated 129 billion lbs of steam for the BCI facility as compared to 144 billion lbs of steam in the same period in 2010.

For the quarter ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $10.6 million, as compared to $11.5 million during the same period in 2010, a decrease of $0.9 million, or 8%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $4.9 million, as compared to $6.0 million during the same period in 2010, a decrease of $1.1 million, primarily due to the Windsor Locks facility selling energy into the ISO-NE day-ahead market as compared to in 2010 when facility derived revenues from participating in the Forward Reserve Market. The decision to have the facility not participate in the Forward Reserve Market in 2011 was due to the fact that the facility could earn more selling into the ISO-NE day-ahead market compared to the lower prices offered for participating the Forward Reserve Market in 2011.

The decrease in revenue from energy / steam sales was primarily due to a decrease of $1.3 million at the Windsor Locks facility as a result of decreased energy rates, in part due to a lower average landed price per mmbtu for natural gas and the change in operating model of the facility, partially offset by an increase of $0.7 million at the Windsor Locks facility due to increased production and a net decrease of $0.1 million at the Sanger facility as a result of the change in energy pricing and production as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below.

Revenue from waste disposal sales for the quarter ended December 31, 2011 totalled $4.0 million, as compared to $4.2 million during the same period in 2010.

For the quarter ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $5.7 million, as compared with $5.5 million in the same period in 2010, an increase of $0.2 million. The overall natural gas expense at the Windsor Locks facility increased $0.2 million (5%), primarily the result of a 11% increase in volume of natural gas consumed, partially offset by a 5% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $4.75 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of $0.1 million (10%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu and a 2% decrease in the volume of natural gas consumed as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.03 per mmbtu. The division reported increased fuel costs of $0.1 million as a result of the stronger U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.4 million, as compared to $5.5 million during the same period in 2010, a decrease of $0.1 million.

For the quarter ended December 31, 2011, the Thermal Energy division's operating profit totalled $4.0 million, as compared to $5.1 million during the same period in 2010, representing a decrease of $1.1 million or 22%. Operating profit in the Thermal Energy division met overall expectations for the quarter ended December 31, 2011.

Divisional Outlook – Thermal Energy

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO NE day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

APCo has commenced the repowering project at the Windsor Locks facility and has entered into an agreement with the steam host that extends the steam supply agreement to 2027. See *APCo Development Division - Windsor Locks* for further discussion on the repowering project.

The EFW facility is expected to continue to perform at throughput and operating costs levels in the first quarter of 2012 consistent with the results experienced in 2011. Pursuant to the waste supply agreement with the Region, the EFW facility charges an initial rate for a base 127,900 tonnes per year of acceptable municipal solid waste in a contract year and, once the base throughput levels are exceeded, the facility charges a lower rate for municipal solid waste received in the remainder of the contract year. The facility exceeded the base throughput levels as of the end of 2011 and, as a result, APCo anticipates lower revenue from waste disposal sales of approximately $0.5 million in the first quarter of 2012 as compared to the first quarter of 2011 as the tip fee charged during January and February will be at the lower rate.

The EFW facility "tip or pay" waste supply agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility.

APCo: Development Division

The Development division works to identify, develop and construct new power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. The Development division is focused on projects within North America and is committed to working proactively with all stakeholders, including local communities. APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

The Development division also creates opportunities through accretive acquisitions of operating assets and prospective projects that are at various stages of development.

Current Development Projects

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of Power Purchase Agreements. The projects are as follows:

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind [1]	Saskatchewan	177	$ 355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$ 230.0	2014	25	247.0
Morse Wind [3, 4]	Saskatchewan	25	$ 70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$ 70.0	2013	20	86.0
Val Eo [1]	Quebec	24	$ 70.0	2015	20	66.0
St. Leon II [1]	Manitoba	17	$ 30.0	2012	25	58.0
Cornwall Solar [1, 2]	Ontario	10	$ 45.0	2013	20	13.4
Total		**352**	**$ 870.0**			**1,283.4**

Notes:
1 PPA signed
2 FIT contract awarded
3 Two 10 MW PPAs; one 5 MW PPA
4 Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

Chaplin Wind

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan.

The project has a targeted commercial operation date of December, 2016. The facility will be constructed at an estimated capital cost of $355 million and consist of approximately 77 multi-megawatt wind turbines. The Project is expected to generate first full year EBITDA of $37.5 million. The 25 year power purchase agreement features a rate escalation provision of 0.6% throughout the term of the agreement. The Project will take advantage of a favourable interconnection location by interconnecting with SaskPower's new P1S 230 kV transmission line from Swift Current to Moose Jaw and will be compliant with SaskPower's latest interconnection requirements.

Amherst Island Wind

The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the OPA as part of the second round of the OPA's FIT program.

The FIT contract originally stated that the OPA had the option to terminate the FIT contract prior to the date that the OPA had issued a Notice to Proceed ("NTP") and APCo had paid the incremental security required by the NTP. On August 2, 2011, the Ontario Ministry of Energy directed the OPA to offer FIT contract holders the opportunity to have the OPA's termination rights under the FIT contract waived. APCo exercised this option on August 9, 2011. As required by the waiver, APCo submitted a domestic content plan on October 14, 2011 and provided a statutory declaration regarding equipment supply commitments by November 30, 2011.

The project is currently contemplated to use efficient Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GWhr of electrical energy annually, depending upon the final turbine selection for the project. Total capital costs for the facility are currently estimated to be $230 million. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. Environmental studies and engineering are underway. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 to 18 months.

Morse Wind Project

The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or option in order to facilitate future expansion.

APCo executed an asset purchase agreement with a local developer ("Kineticor") to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APCo independently. All of the individual projects comprising the Morse Wind Project were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011. Upon SaskPower's approval and execution of the Kineticor PPAs, Kineticor will then assign the PPAs to APCo. All three of the projects are expected to be completed contemporaneously in early 2014.

The total annual energy production for the Morse Wind Project is estimated to be 93,000 MWhr. The capital cost to construct the Morse Wind Project is currently estimated to be $65-$70 million, inclusive of acquisition costs. The first year PPA rate is set at $101.98 per MWhr for the first full year of operations, which APCo expects to occur in 2014, with an annual escalation provision of 2% over the expected 20 year term.

Quebec Community Wind Projects

In 2010, APCo worked with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded power purchase contracts that stipulate the use of ENERCON wind turbines.

Saint-Damase

The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APCo. The first 24 MW phase of the project is expected to be comprised of eight to twelve generators (depending on capacity of the selected wind turbine model), producing approximately 86,000 MWhr annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

The interest of APUC in the project is subject to final negotiations with the municipality but, in any event, will not be less than 50%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing. In July 2011, meetings were conducted with participating landowners in addition to an open house to obtain additional community feedback. All major environmental authorizations are targeted for completion by the end of 2012.

Val-Éo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight generators, producing approximately 66,000 MWhr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interest of APUC in the project is subject to final negotiations with the cooperative but, in any event, will not be less 25%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing with all major authorizations targeted for completion by the end of 2012.

St. Leon II

In July 2011, APCo executed a 25-year power purchase agreement with Manitoba Hydro in respect of St. Leon II (a 16.5 MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba). Construction of this project commenced on August 30, 2011 using 10 Vestas V82 turbines. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The project is expected to achieve commercial operation in the second quarter of 2012. The total capital cost of the project is expected to be $29.5 million.

Cornwall Solar

APCo entered into a share purchase agreement with EffiSolar Energy Corporation ("EffiSolar"), to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the FIT Pipeline have submitted Feed-in-Tariff applications for an additional 100MWac.

The Project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MWhr, resulting in expected initial annual revenues of approximately $6.2 million. The Project contemplates the use of a ground-mounted PV array system, with expected annual generation of approximately 13,400 MWh, enough to provide electricity to approximately 1,000 homes.

Following the completion of all regulatory submissions and approvals, construction of the project is expected to begin in the second half of 2012, with a Commercial Operation Date estimated in early 2013. The Project is being developed on two parcels of leased land totalling approximately 138 acres.

Total capital cost of the project is targeted at approximately $45 million, which amount includes the consideration to be paid for the acquisition of the Project. Funding for the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

Windsor Locks Repowering

The Windsor Locks facility is a 56 MW natural gas powered electrical and steam energy generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to an energy services agreement ("ESA").

APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027, and supports the installation of a new 14 MW Solar Titan combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is in construction with commercial operation expected in July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Windsor Locks facility of approximately U.S. $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO NE market when it is commercially profitable to do so. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("ITC") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

Liberty Utilities
WATER | GAS | ELECTRIC

Liberty Utilities' business strategy is to operate and grow its nationwide portfolio of rate regulated water, natural gas and electric distribution and wastewater collection and treatment utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best-in-class customer care for all utility ratepayers and building constructive regulatory relationships in the jurisdictions in which it operates.

As a result of the current and expected growth, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. This approach will also enhance operational efficiencies and garner greater economies of scale while preserving the customer and regulator focus of the businesses which arises from the independent operations of these regions. As a result of this change Liberty Utilities now has two separately managed regions - Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco).

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed initially to deliver electrical and natural gas distribution services following the acquisition of Granite State and EnergyNorth. A fourth management region, Liberty Utilities (Central), will initially be created to manage the delivery of Liberty Utilities services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from Atmos.

Liberty Utilities is committed to being a leading utility provider of water, natural gas and electric utility services while providing stable and predictable earnings to APUC from its utility operations. Liberty Utilities has presented the division's results in both the reporting currency and its functional currency. Liberty Utilities believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Utilities' functional currency without the impact of foreign exchange.

Liberty Utilities (South)

Liberty Utilities (South) operates in Arizona, Texas, Missouri and Illinois and currently provides rate regulated water and wastewater utility services to approximately 76,000 customers in those states.

	Year ended December 31 2011	Year ended December 31 2010	Year ended December 31 2011	Year ended December 31 2010
Number of				
Wastewater connections			**36,750**	35,420
Wastewater treated (millions of gallons)			**2,000**	2,000
Water distribution connections			**38,750**	37,666
Water sold (millions of gallons)			**5,600**	5,500
	U.S. $	U.S. $	**Can $**	Can $
NBV of Assets for regulatory purposes (U.S. $)	**155,763**	155,258		
Revenue				
Wastewater treatment	**$ 23,295**	$ 20,202	**$ 23,031**	$ 20,935
Water distribution	**21,574**	15,877	**21,330**	16,453
Other Revenue	**636**	601	**628**	623
	$ 45,505	$ 36,680	**$ 44,989**	$ 38,011
Expenses				
Operating expenses	**(22,959)**	(21,371)	**(22,720)**	(22,199)
Other income	**482**	154	**488**	149
Divisional operating profit	**$ 23,028**	$ 15,463	**$ 22,757**	$ 15,961

Liberty Utilities (South) is committed to being a leading utility provider of safe, high quality and reliable water and wastewater services while providing stable and predictable earnings from its utility operations. Liberty Utilities (South) has presented the division's results in both the reporting currency and its functional currency. Liberty Utilities (South) believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Utilities (South)'s functional currency without the impact of foreign exchange.

Liberty Utilities (South) reports total connections, inclusive of vacant connections rather than customers. Liberty Utilities (South) had 36,750 wastewater connections as at December 31, 2011, as compared to 35,420 as at December 31, 2010, an increase of 1,330 in the period or 3.8%. Liberty Utilities (South) had 38,750 water distribution connections as at December 31, 2011, as compared to 37,666 as at December 31, 2010, representing an increase of 1,084 in the period or 2.8%. Total connections include approximately 1,800 vacant wastewater connections and 1,400 vacant water distributions connections as at December 31, 2011. Liberty Utilities (South)'s change in water distribution and wastewater treatment customer base during the period is primarily due to the acquisition of two small utilities in Missouri during the last quarter of 2011 and modest growth at Liberty Utilities (South)'s other facilities.

Liberty Utilities (South) has investments in regulatory assets of U.S. $155.8 million across four states as at December 31, 2011, as compared to U.S. $155.3 million as at December 31, 2010.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (South) provided approximately 5.6 billion U.S. gallons of water to its customers, treated approximately 2.0 billion U.S. gallons of wastewater and sold approximately 270 million U.S. gallons of treated effluent.

For the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $45.5 million as compared to U.S. $36.7 million during the same period in 2010, an increase of U.S. $8.8 million or 24%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state regulators over the past two years. Rate cases ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates.

Revenue from water distribution totalled U.S. $21.6 million as compared to U.S. $15.8 million during the same period in 2010, an increase of U.S. $5.7 million or 36%. The annual water distribution revenue was impacted, primarily due to the implementation of rate increases of U.S. $3.9 million at the Litchfield Park Service Company ("LPSCo") facility, U.S. $1.0 million at the Rio Rico facility and U.S. $0.8 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $23.3 million, as compared to U.S. $20.2 million during the same period in 2010, an increase of U.S. $3.1 million or 15%. The annual wastewater treatment revenue was impacted by increased revenue, primarily due to the implementation of rate increases of U.S. $2.8 million at the LPSCo facility and U.S. $0.4 million at the Black Mountain facility, partially offset by lower revenue at the Rio Rico facility of $0.4 million, as compared to the same period in 2010. In addition, revenue increased U.S. $0.4 million at seven wastewater treatment facilities, primarily due to customer increases at the Tall Timbers facility as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses totalled U.S. $23.0 million, as compared to U.S. $21.4 million during the same period in 2010, an increase of U.S. $1.6 million or 7%. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.5 million and U.S. $1.0 million related to increased wages, salary and other operating costs as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $23.0 million as compared to U.S. $15.5 million in the same period in 2010, an increase of U.S. $7.6 million or 49%. Liberty Utilities (South)'s operating profit exceeded expectations for the year ended December 31, 2011 due to increased customer counts and lower than expected power and operating labour costs.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $45.0 million as compared to $38.0 million during the same period in 2010, an increase of $7.0 million. Revenue from wastewater treatment totalled $23.0 million, as compared to $20.9 million during the same period in 2010, an increase of $2.1 million. Revenue from water distribution totalled $21.3 million, as compared to $16.5 million during the same period in 2010, an increase of $4.9 million. Liberty Utilities (South) reported decreased revenue from operations of $1.9 million in 2011 as a result of the weaker U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the year ended December 31, 2011, operating expenses totalled $22.7 million, as compared to $22.2 million during the same period in 2010, an increase of $0.5 million. Liberty Utilities (South) reported lower expenses from operations of $1.2 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $22.8 million as compared to $16.0 million in the same period in 2010, an increase of $6.8 million.

	Three months ended December 31		Three months ended December 31	
	2011	**2010**	**2011**	**2010**
Number of				
Wastewater treated (millions of gallons)			**500**	500
Water sold (millions of gallons)			**1,300**	1,400
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Wastewater treatment	**5,855**	5,543	**5,993**	5,649
Water distribution	**5,223**	4,074	**5,347**	4,152
Other Revenue	**123**	205	**126**	208
	$ 11,201	$ 9,822	**$ 11,466**	$ 10,009
Expenses				
Operating expenses	**(5,901)**	(5,264)	**(6,039)**	(5,370)
Other income	**229**	152	**224**	81
Divisional operating profit	**$ 5,529**	$ 4,710	**$ 5,651**	$ 4,720

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, Liberty Utilities (South) provided approximately 1.3 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 35 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $11.2 million as compared to U.S. $9.8 million during the same period in 2010, an increase of U.S. $1.4 million or 14%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state legislators over the past two years.

Revenue from water distribution totalled U.S. $5.2 million, as compared to U.S. $4.1 million during the same period in 2010, an increase of U.S. $1.1 million or 28%. The fourth quarter water distribution revenue increased primarily due to the implementation of rate increases of U.S. $0.6 million at the LPSCo facility, U.S. $0.3 million at the Rio Rico facility and U.S. $0.3 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $5.9 million, as compared to U.S. $5.5 million during the same period in 2010, an increase of U.S. $0.3 million or 6%. The fourth quarter wastewater treatment revenue increased primarily from the implementation of rate increases of U.S. $0.5 million at the LPSCo facility and U.S. $0.2 million at ten wastewater treatment facilities primarily due to increased customers as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses totalled U.S. $5.9 million, as compared to U.S. $5.3 million during the same period in 2010. Overall expenses increased U.S. $0.6 million or 12% as compared to the same period in 2010. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.1 million and U.S. $0.4 million related to wages, salary and other operating costs as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $5.5 million as compared to U.S. $4.7 million in the same period in 2010, an increase of U.S. $0.8 million or 17%. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $11.5 million, as compared to $10.0 million during the same period in 2010. Revenue from wastewater treatment totalled $6.0 million, as compared to $5.6 million during the same period in 2010, an increase of $0.3 million. Revenue from water distribution totalled $5.3 million, as compared to $4.2 million in the same period in 2010, an increase of $1.2 million. Liberty Utilities (South) reported increased revenue from operations of $0.1 million in the fourth quarter of 2011 as a result of the stronger U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the quarter ended December 31, 2011, operating expenses totalled $6.0 million, as compared to $5.4 million during with same period in 2010, an increase of $0.6 million. Liberty Utilities (South) reported lower expenses from operations of $0.4 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $5.7 million as compared to $4.7 million in the same period in 2010, an increase of $0.9 million. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Outlook – Liberty Utilities (South)

Liberty Utilities (South) expects continuing modest customer growth throughout its service territories in 2012.

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011. Liberty Utilities (South) attributes the majority of the revenue increases in the year ended December 31, 2011 to the impact of completed rate cases.

Liberty Utilities (West)

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of approximately U.S. $136.1 million. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility, California Pacific Electric Company ("Calpeco").

The acquisition of the California Utility was completed following receipt of all U.S. state and federal regulatory approvals. Contemporaneously with the closing, Emera exchanged previously announced subscription receipts into 8.532 million APUC common shares at a purchase price of $3.25 per share. The proceeds of the subscription receipts were utilized to fund Liberty Energy's share of the equity in acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured notes. The notes are a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes maturing December 29, 2020 and U.S. $25 million of 5.59% fifteen year notes maturing December 29, 2025.

Liberty Utilities (West) operates in California and currently provides local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region.

	Year ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Number of Customer Accounts				
Residential			41,346	—
Commercial – Small			5,506	—
Commercial – Large			54	—
Total Customer Accounts			**46,906**	
Customer Usage (GWhr)				
Residential			291.2	—
Commercial – Small			174.2	—
Commercial – Large			136.6	—
Total Customer Usage (GWhr)			**602.0**	
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,843**	—		
Revenue				
Utility energy sales and distribution	**$ 78,125**	$ —	**$ 77,368**	$ —
Less:				
Cost of sales – Energy*	**(46,917)**	—	**(46,491)**	
Net utility energy sales	**$ 31,208**	$ —	**$ 30,877**	$ —
Expenses				
Operating expenses	**(16,142)**	—	**(16,019)**	—
Division operating profit**	**$ 15,066**	$ —	**$ 14,858**	$ —

* Cost of Sales - Energy consists of energy purchases. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

** Represents 100% of investment in the California Utility.

As at December 31, 2011, Liberty Utilities (West) holds a 50.001% controlling interest in the California Utility. As the California Utility was acquired on January 1, 2011 there are no comparable results for 2010.

Liberty Utilities reports active connections, exclusive of vacant connections rather than total connections. Liberty Utilities (West) had approximately 41,300 residential electrical customer accounts and 5,550 commercial electrical customer accounts, as at December 31, 2011.

Liberty Utilities (West) has investments in regulatory assets of U.S. $155.8 million in California as at December 31, 2011.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 602,000 MWhr of energy.

For the year ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $78.1 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are ultimately passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net utility energy sales revenue for Liberty Utilities (West) totalled U.S. $31.2 million.

For the year ended December 31, 2011, energy purchases for Liberty Utilities (West) totalled U.S $46.9 million. During the year ended December 31, 2011, the California Utility purchased approximately 602,000 MWhr of energy at rates averaging U.S. $77.9 per MWhr.

For the year ended December 31, 2011, operating expenses, excluding energy purchases, totalled U.S. $16.1 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $15.1 million. Liberty Utilities (West)'s operating profit did not meet expectations for the year ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by lower than budgeted property taxes and higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $77.4 million. For the year ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $30.9 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $46.5 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $16.0 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $14.9 million.

	Three months ended December 31 2011	Three months ended December 31 2010	Three months ended December 31 2011	Three months ended December 31 2010
Customer Usage (GWhr)				
Residential			69.4	—
Commercial – Small			50.4	—
Commercial – Large			40.4	—
Total Customer Usage (GWhr)			**160.2**	
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Utility energy sales and distribution	**$ 20,805**	$ —	**$ 21,287**	$ —
Less:				
Cost of Sales – Energy*	**(13,176)**	—	**(13,486)**	
	$ 7,629	$ —	**$ 7,801**	$ —
Expenses				
Operating expenses	**(5,126)**	—	**(5,243)**	—
Division operating profit**	**$ 2,503**	$ —	**$ 2,558**	$ —

* Cost of Sales - Energy consists of energy purchases. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.

** Represents 100% of investment in the California Utility.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 160,100 MWhr of energy.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $20.8 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net utility energy sales revenue totalled U.S. $7.6 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled U.S $13.2 million. During the quarter, the California Utility purchased approximately 160,100 MWhr of energy at rates averaging U.S. $82.3 per MWhr.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses, excluding energy purchases, totalled U.S. $5.1 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $2.5 million. Liberty Utilities (West)'s operating profit did not meet expectations for the three months ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $21.3 million. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $7.8 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $13.5 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $5.2 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $2.6 million.

Outlook – Liberty Utilities (West)

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the CPUC seeking, among other things, an increase of 10.0%, or $7.5 million in general rates, comprised of a $3.3 million increase in vegetation management costs, $13.0 million increase in distribution rates offset by reductions in commodity costs of $8.8 million. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

On April 29, 2011, Liberty Utilities announced it had reached an agreement with Emera to acquire the interest in the California Utility held by Emera. Emera agreed to sell its 49.999% direct ownership in the California Utility, with closing of such transaction subject to regulatory approval. As consideration Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the California Utility ownership transfer (expected in 2012) and the balance of the shares will be issued following completion of the California Utility's first rate case, expected to be completed in early 2013.

Liberty Utilities (East)

On December 9, 2010, Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State, a rate regulated New Hampshire electric utility, and EnergyNorth, a rate regulated New Hampshire natural gas utility for a total purchase price of U.S. $285 million, plus working capital and subject to certain other closing adjustments. The purchase prices for Granite State and EnergyNorth are based on anticipated regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively. Upon completion of the transaction, the results of these utilities will be reported in a newly formed Liberty Utilities (East) division.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire.

The closing of the transaction is subject to approval by the NHPUC. Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

In connection with these acquisitions, Emera has committed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. The issuance of these subscription receipts is subject to regulatory approval.

Financing of these acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Utilities (East) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

Liberty Utilities (Central)

On May 13, 2011, Liberty Utilities (Central) entered into an agreement with Atmos to acquire the gas utilities located in Missouri, Iowa, and Illinois. Total purchase price for the gas utilities is approximately U.S. $124 million, plus working capital and subject to certain other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million, plus working capital and subject to certain other closing adjustments, representing a purchase price multiple of 1.106x. The gas utilities currently provide natural gas local distribution service to approximately 84,000 customers (57,000 in Missouri, 23,000 in Illinois, and 4,000 in Iowa).

The closing of the transaction is subject to approval by the MPSC, the IUB, and the ICC. Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Upon completion of the transaction, the results of these utilities will be reported in the Liberty Utilities (Central) division. It is expected that management responsibility for the rate regulated water utility systems located in Missouri and currently reported in the results of Liberty Utilities (South) will be transferred to the newly formed Liberty Utilities (Central) following the acquisition of the Atmos assets.

Financing of this acquisition is expected to occur simultaneously with the closing of the transaction. Liberty Utilities (Central) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

APUC: Corporate

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	**2011 (millions)**	**2010** (millions)
Corporate and other expenses:				
Administrative expenses and management costs	**4.8**	5.1	**17.5**	14.9
Write down of intangibles and property plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss / (Gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Interest expense	**7.6**	6.5	**30.4**	24.8
Interest, dividend and other Income	**(0.8)**	(1.0)	**(3.0)**	(3.6)
Loss / (Gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)

2011 Annual Corporate and Other Expenses

During the year ended December 31, 2011, management and administrative expenses totalled $17.5 million, as compared to $14.9 million in the same period in 2010. The expense increase in the year ended December 31, 2011 results from additional personnel, increased wages, additional costs required to administer APUC's operations, stock option expense, franchise taxes, a provision related to water lease dues at the Cote St.-Catherine facility and other costs as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1.3 million representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. The carrying value was written down to its fair value less cost to sell resulting in an impairment charge of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the expected sales price. In addition, Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes.

Subsequent to the year end, the Region elected not to extend the existing EFW waste processing contract and is seeking competitive proposals from several waste management companies, including EFW. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and APCo recognized an impairment charge on intangible assets of $13.4 million.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1.8 million representing the difference between the carrying value of the assets and their fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

For the year ended December 31, 2011, interest expense totalled $30.4 million as compared to $24.8 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s senior unsecured notes and APCo's senior unsecured debentures compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures in April 2011, as compared to the same period in 2010.

For the year ended December 31, 2011, interest, dividend and other income totalled $3.0 million, as compared to $3.6 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

Loss on derivative financial instruments consists of realized and unrealized mark-to-market losses on interest rate swaps and forward energy purchase contracts during 2011. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $23.0 million was recorded in the year ended December 31, 2011, as compared to a recovery of $20.8 million in the same period in 2010. There are two primary reasons for the income tax recovery for the period ended December 31, 2011. First, in the third quarter of 2011, APUC completed a capital structure project to ensure its operating subsidiaries have a capital structure that is appropriate for its business sector and that uses the functional currency in which it operates. Therefore as part of this process, APUC converted Canadian dollar denominated intercompany notes with a U.S. subsidiary of APCo into U.S. dollar denominated preferred shares resulting in a realized foreign exchange loss for tax purposes and a release of the valuation allowance associated with the unrealized foreign exchange loss accumulated to that point, thereby creating a future tax asset of approximately $15.6 million that is now available as additional tax shelter in future years. Secondly, on October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. Included in future income tax recoveries for the year ended December 31, 2011 is $6.6 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2011 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2011, management and administrative expenses totalled $4.8 million, as compared to $5.1 million in the same period in 2010. The expense decrease in the three months ended December 31, 2011 primarily results from decreased capital taxes, partially offset by the reasons discussed in "*2011 Annual Corporate and Other Expenses*" above as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes. Subsequent to the year end, EFW wrote off the remaining intangible assets associated with the existing waste management and energy contracts with the Region and recognized an impairment charge on intangible assets of $13.4 million. See the discussion in the annual corporate and other expenses section above for details related to this expense.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and the equipment at the Crossroads thermal facility in New Jersey. See the discussion in the annual corporate and other expenses section above for details related to this expense.

For the quarter ended December 31, 2011, interest expense totalled $7.6 million as compared to $6.5 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s long term debt private placement compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures, as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest, dividend and other income totalled $0.8 million, as compared to $1.0 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

Loss (gain) on derivative financial instruments consists of realized and unrealized mark-to-market losses on interest rate swaps and forward energy purchase contracts during the quarter. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $6.6 million was recorded in the three months ended December 30, 2011, as compared to a recovery of $16.4 million in the same period a year ago. The income tax recovery for the three months ended December 31, 2011 results from those factors discussed in "*2011 Annual Corporate and Other Expenses"* above as compared to the same period in 2010. Included in future income tax recoveries for the three months ended December 31, 2011 is $1.2 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

Non-GAAP Performance Measures

Reconciliation of Adjusted EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense, income tax expense or recoveries, acquisition costs, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended December 31		**Year ended December 31**	
	2011 (millions)	2010 (millions)	**2011 (millions)**	2010 (millions)
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add (deduct):				
Net earnings attributable to the non controlling interest	**0.5**	0.1	**3.9**	0.4
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)
Interest expense	**7.6**	6.5	**30.4**	24.8
Acquisition Costs	**1.2**	2.3	**3.0**	3.0
Write down of intangibles, property, plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss (gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Loss (gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Depreciation and amortization	**11.6**	12.1	**45.9**	46.6
Adjusted EBITDA	**$ 24.3**	$ 20.8	**$ 105.2**	$ 75.1

For the year ended December 31, 2011, Adjusted EBITDA totalled $105.2 million as compared to $75.1 million, a net increase of $30.1 million or 40% as compared to the same period in 2010. For the quarter ended December 31, 2011, Adjusted EBITDA totalled $24.3 million as compared to $20.8 million, a net increase of $3.5 million or 17% as compared to the same period in 2010.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

	Three months ended December 31, 2011 (millions)	Year ended December 31, 2011 (millions)
Comparative Prior Period Adjusted EBITDA	$ 20.8	$ 75.1
Significant Changes:		
Acquisition of the California Utility	2.5	15.1
EFW facility	(0.4)	5.2
Liberty Utilities (South) revenue increases primarily due to rate case approvals	0.7	7.2
Hydro Renewable due to improved hydrology (reduced hydrology in Q4)	(0.5)	6.1
St. Leon – primarily due to an increased wind resource	1.6	3.0
Administration and management costs	0.3	(2.6)
Lower results from the weaker U.S. dollar (stronger in Q4)	1.2	(1.7)
Tinker Hydro / AES primarily due to lower energy demand	(0.2)	(1.0)
Windsor Locks – change in operating model	(0.4)	(1.9)
Other	(1.3)	0.7
Current Period Adjusted EBITDA	**$ 24.3**	**$ 105.2**

Reconciliation of adjusted net earnings to net earnings

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. APUC uses adjusted net earnings to assess its performance without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs and write down of intangibles and property, plant and equipment as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the audited Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

	Three months ended December 31, 2011		Year ended December 31, 2011	
	2011 (millions)	2010 (millions)	2011 (millions)	2010 (millions)
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add:				
Loss (gain) on derivative financial instruments, net of tax	**1.0**	(1.2)	**3.9**	0.7
Loss (gain) on foreign exchange, net of tax	**0.4**	(0.1)	**(0.7)**	(0.5)
Write down of intangibles, property, plant and equipment	**13.1**	2.5	**13.2**	2.5
Acquisition costs, net of tax	**0.7**	1.4	**1.8**	1.8
Adjusted net earnings	**$ 6.7**	$ 18.2	**$ 41.6**	$ 22.5
Adjusted net earnings per share	**$ 0.05**	$ 0.19	**$ 0.36**	$ 0.24

For the year ended December 31, 2011, adjusted net earnings totalled $41.6 million as compared to adjusted net earnings of $22.5 million, an increase of $19.1 million as compared to the same period in 2010. The increase in adjusted net earnings in the year ended December 31, 2011 is primarily due to increased earnings from operations, partially offset by increased interest and administrative expenses and lower recoveries of deferred taxes as compared to the same period in 2010.

For the three months ended December 31, 2011, adjusted net earnings totalled $6.7 million as compared to $18.2 million, a decrease of $11.5 million as compared to the same period in 2010. The decrease in adjusted net earnings in the three months ended December 31, 2011 is primarily due to increased interest and administrative expenses and reduced recoveries of deferred taxes, partially offset by increased earnings from operations as compared to the same period in 2010.

Summary of Property, Plant and Equipment Expenditures

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	2011 (millions)	2010 (millions)
APCo				
Renewable Energy Division				
Capital expenditures	**$ 6.7**	$ 1.0	**$ 25.6**	$ 2.3
Acquisition of operating entities	**—**	—	**—**	40.3
Total	**$ 6.7**	$ 1.0	**$ 25.6**	$ 42.6
Thermal Energy Division				
Capital expenditures	**$ 4.5**	$ 0.5	$ 13.6	$ 11.6
Total	**$ 4.5**	$ 0.5	**$ 13.6**	$ 11.6
LIBERTY UTILITIES				
South				
Capital Investment in regulatory assets	**$ 1.5**	$ 4.5	**$ 10.9**	$ 6.6
Acquisition of operating entities	**0.4**	—	**1.3**	2.1
Total	**$ 1.9**	$ 4.5	**$ 12.2**	$ 8.7
West				
Capital Investment in regulatory assets	**$ 4.9**	$ —	**$ 10.3**	$ —
Acquisition of operating entities	**1.4**	3.1	**98.7**	3.1
Total	**$ 6.3**	$ 3.1	**$ 109.0**	$ 3.1
Consolidated				
Total APCo				
Capital expenditures	$ 11.2	$ 1.5	**$ 39.2**	$ 13.9
Acquisition of operating entities	—	—	**—**	40.3
Total Liberty Utilities				
Capital investment in regulatory assets	$ 6.4	4.5	**$ 21.2**	6.6
Acquisition of operating entities	1.8	3.1	**100.0**	5.2
Corporate	0.1	0.1	**0.4**	0.2
Total	**$ 19.5**	$ 9.2	**$ 160.8**	$ 66.2

APUC's consolidated capital expenditures in the year ended December 31, 2011 increased as compared to the same period in 2010 primarily due to the acquisition of the California Utility, the start of the construction of St. Leon II and the Windsor Locks repowering project.

Property, plant and equipment expenditures for 2012 are anticipated to be between $60 million and $70 million, including approximately $14.0 million related to ongoing requirements by Liberty Utilities (South), $11.0 million at Liberty Utilities (West) related to the California Utility, $15.5 million related to the APCo Thermal division, primarily related to the Windsor Locks repowering and major maintenance at the Sanger facility, and $18.5 million related to the APCo Renewable Energy division, primarily related to the St. Leon II expansion and a major project at the Tinker facility.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2011 Annual Property Plant and Equipment Expenditures

During the year ended December 31, 2011, APCo incurred net capital expenditures of $39.2 million, as compared to $13.9 million during the comparable period in 2010. APCo also invested $40.3 million to acquire operating assets/entities during the comparable period in 2010.

During the year ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $25.6 million, as compared to $2.3 million in the comparable period in 2010. The St. Leon II development and the turbine overhaul project at the Tinker facility were the major individual projects initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets in 2010 relate to the Tinker Assets located in New Brunswick and Maine. The APCo Thermal Energy division's net capital expenditures were $13.6 million, as compared to $11.6 million in the comparable period in 2010. The major expenditures in the year primarily relates to the Windsor Locks repowering project and investments at the Sanger facility. In the comparable period, the capital expenditures primarily relate to the EFW facility where major capital maintenance was underway.

During the year ended December 31, 2011, Liberty Utilities invested $21.2 million in regulatory assets, as compared to $6.6 million during the comparable period in 2010. These investments comprise of $10.9 million at Liberty Utilities (South) and $10.3 million at Liberty Utilities (West). Liberty Utilities also invested $100.0 million to acquire operating assets/entities, primarily related to Liberty Utilities (West)'s investment of $98.7 million to acquire the California Utility in 2011.

2011 Fourth Quarter Property Plant and Equipment Expenditures

During the quarter ended December 31, 2011, APCo incurred net capital expenditures of $11.2 million, as compared to $1.5 million during the comparable period in 2010.

During the quarter ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $6.7 million, as compared to $1.0 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the St. Leon II development and the turbine overhaul project at the Tinker facility. The APCo Thermal Energy division's net capital expenditures were $4.5 million, as compared to $0.5 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the Windsor Locks repowering project and investments at the Sanger facility.

During the quarter ended December 31, 2011, Liberty Utilities invested $6.4 million, as compared to $4.5 million during the comparable period in 2010. These investments comprise of $1.5 million at Liberty Utilities (South) and $4.9 million at Liberty Utilities (West). During the quarter, Liberty Utilities (West) recorded an adjustment to the purchase price of the California Utility which reduced the purchase price by $1.4 million.

Dam Safety Legislation

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. All eleven dam safety evaluations have now been completed. Out of these, nine remedial plans have been submitted to the Quebec government and two are undergoing options analysis by APCo. The nine remedial plans have been accepted by the Quebec government and one is still being reviewed.

APCo has spent approximately $1.5 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APCo currently estimates further capital expenditures of approximately $16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

	Total	**2012**	**2013**	**2014**	**2015**
Estimated future Bill C-93 Capital Expenditures	**16,900**	1,100	5,300	7,700	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities.

- The dam safety evaluation for the Mont Laurier facility was completed in 2008 and APCo's proposed remediation plan has now been accepted by the Quebec government. APCo has been performing engineering and permitting since 2010 and received the Certificate of Authorization from the Quebec government in November 2011. APCo anticipates completing the on-site remediation work in 2012.
- In respect of the Donnacona facility, APCo completed the dam safety evaluation in 2007 and has been investigating alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates. APCo anticipates completing the engineering in 2012 and performing the remedial work in 2013 and 2014.

- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCO will review the results of the condition assessment and finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo has been corresponding with the Quebec government and other stakeholders about these options since 2007. APCo anticipates completion of any required work on these dams by 2015.
- The dam remediation work related to Chute Ford will be completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013. No dam remediation work is required at the Arthurville, Hydraska, and Ste-Brigitte facilities.
- The dam remediation work related to the Rawdon facility was completed in 2011.

In addition to the C-93 related dam remediation work, APCo has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

LIQUIDITY AND CAPITAL RESERVES

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2011 under the Facility:

	2011 Q4 (millions)	2011 Q3 (millions)	2011 Q2 (millions)	2011 Q1 (millions)	2010 Q4 * (millions)
Committed and available Facility	$ 120.0	$ 120.0	$ 142.0	$ 142.0	$ 142.0
Funds Drawn on Facility	—	(12.0)	(70.0)	(65.0)	(64.5)
Letters of Credit issued	(39.6)	(40.1)	(32.5)	(32.9)	(33.1)
Remaining available Facility	**$ 80.4**	**$ 67.9**	**$ 39.5**	**$ 44.1**	**$ 44.4**
Cash on Hand	72.9	15.5	8.7	2.5	**4.7**
Total liquidity and capital reserves	**$ 153.3**	**$ 83.4**	**$ 48.2**	**$ 46.6**	**$ 49.1**

* Reflects availability as at December 31, 2010, under the terms of a three year Facility renewed subsequent to December 31, 2010, having a maturity of February 14, 2014.

During the first quarter, APCo concluded negotiations with its bank syndicate on the renewal of the Facility for a three year term with a maturity date of February 14, 2014. Algonquin also reduced the total of the Facility to $120 million following the completion of the Senior Unsecured Debenture offering of APCo in July 2011. As at December 31, 2011, no amounts had been drawn on the Facility as compared to $64.5 million as at December 31, 2010. In addition to amounts actually drawn, there were $39.6 million in letters of credit outstanding as at September 30, 2011. APCo had $80.4 million of committed and available bank facilities remaining and $72.9 million of cash resulting in $153.3 million of total liquidity and capital reserves.

On July 25, 2011, APCo completed the Senior Unsecured Debenture offering of $135 million, the net proceeds of which were used to repay the Airsource senior debt financing having a principal amount outstanding of $67.8 million with the balance being used to reduce amounts outstanding on the Facility.

On October 27, 2011, APUC completed an equity offering of $85.3 million, a portion of the net proceeds of which have been used to repay the outstanding balance on the Facility. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

On January 19, 2012, Liberty Utilities announced that it had entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the “Liberty Facility”) with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility includes provisions which allow the available credit to be increased to accommodate future working capital needs or other requirements.

APUC intends to use its liquidity and capital reserves to fund announced capital expansion projects in APCo and to partially fund announced share acquisitions in Liberty Utilities.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of December 31, 2011 is shown below:

	Total (millions)	Due less than 1 year (millions)	Due 1 to 3 years (millions)	Due 4 to 5 years (millions)	Due after 5 years (millions)
Long-term debt obligations[1]	$ 332.7	$ 1.6	$ 3.7	$ 16.5	$ 310.9
Convertible debentures[2]	$ 122.3	—	—	59.7	62.6
Interest on long-term debt obligations	$ 227.9	25.6	40.2	37.3	124.8
Long term service agreements	$ 94.4	4.6	8.2	8.6	73.0
Purchased power	$ 227.5	45.1	91.5	90.9	—
Accounts payable/purchase obligations	$ 57.3	57.3	—	—	—
Capital Projects	$ 7.9	7.9	—	—	—
Energy forward purchase contract	$ 1.2	0.8	0.4	—	—
Interest rate swap	$ 6.9	2.1	3.7	1.1	—
Lease obligations	$ 2.7	1.2	1.2	0.3	—
Other obligations	$ 9.8	1.1	0.5	0.5	7.7
Total obligations	$1,090.6	$ 147.3	$ 149.4	$ 214.9	$ 579.0

1 Long term obligations include regular payments related to long term debt and other obligations.

2 Convertible debentures include the Series 2A Debentures which were redeemed for equity effective February 24, 2012.

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2011, APUC had 136,122,780 issued and outstanding shares. Following the Series 2A Redemption, APUC had 146,741,635 shares outstanding.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2011, APUC does not have any issued and outstanding preferred shares.

As at December 31, 2011, APUC had issued to Emera a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the Granite State and EnergyNorth transactions at a purchase price of $5.00. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost to acquire Granite State and EnergyNorth.

On April 29, 2011, APUC agreed to issue to Emera 8.2 million shares with regards to the acquisition by Liberty Utilities of Emera's 49.999% direct ownership in the California Utility. The approval on the ownership transfer is expected in early 2012. The payment of shares is to be made in two tranches with approximately half of the shares being issued following regulatory approval of the ownership transfer and the balance of the shares being issued following completion of the California Utility's first rate case which is expected to be completed in 2012.

On April 30, 2011, APUC committed to issuance to Emera of a treasury subscription of subscription receipts convertible into approximately 6.9 million APUC common shares upon closing of the transaction related to the acquisition of an interest in a portfolio of 370MW wind projects. This treasury subscription was terminated when APCo announced on January 27, 2012 that it no longer intended to proceed with the First Wind acquisition.

On April 7th, 2011, APUC provided the holders of its Series 1A Debentures with notice of its intention to redeem for equity, all of the issued and outstanding Series 1A Debentures. Prior to the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On the Redemption Date, APUC issued and delivered 430,666 APUC shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of APUC shares on the Redemption Date. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

Subsequent to December 31, 2011, on January 20, 2012, APUC provided the holders of its Series 2A 6.35% convertible unsecured subordinated debentures due November 30, 2016 ("Series 2A Debentures") notice of its intention to redeem for equity, effective February 24, 2012 ("Series 2A Redemption Date"), all of the issued and outstanding Debentures. Prior to the Series 2A Redemption Date, a principal amount of $2,916 of Series 2A Debentures were converted into 485,998 shares of APUC.

On the Series 2A Redemption Date, APUC issued and delivered 9,836,520 APUC shares to the remaining holders of Series 2A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures of $57,041, by 95% of the current market price of APUC shares on the Series 2A Redemption Date. As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

On December 2, 2009, APUC issued 63,250 convertible unsecured debentures at a price of $1,000 for each debenture maturing on June 30, 2017 ("Series 3 Debentures"). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures' maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional shares.

On December 31, 2011, there were 62,571 Series 3 Debentures outstanding with a face value of $62,571.

During the three months ended December 31, 2011, a principal amount of $129 Series 3 Debentures were converted into 30,710 shares APUC. During the year ended December 31, 2011, a principal amount of $334 Series 3 Debentures were converted into 79,517 shares APUC. Subsequent to the end of the quarter, $66 Series 3 Debentures were converted to 15,711 shares.

SHARE BASED COMPENSATION PLANS

For the year ended December 31, 2011, APUC recorded $0.7 million (2010 - $0.1 million) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1.2 million and $0.1 million respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

STOCK OPTION PLAN

On June 23, 2010, APUC's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. On June 21, 2011, APUC's shareholders approved amendments to the Plan to limit non-employee director participation in the Plan and to require shareholder approval to make further amendments to the plan with respect to a number of items as more fully described in the management information circular for the 2011 annual and special meeting of shareholders.

During the year ended December 31, 2010, 1,160,204 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $4.05. One-third of the options vest on each of January 1, 2011, 2012 and 2013. During the year ended December 31, 2011, the Board approved the following grant of options:

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;

- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.68.

Subsequent to year end on March 14, 2012, 1,194,606 options were granted which allow for the purchase of common shares at a price of $6.22.

All options are issued at the market price of the underlying common share at the date of grant. In each case, one-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

During the year ended December 31, 2011, no options were exercised. As at December 31, 2011, APUC had 2,487,104 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

As at December 31, 2011, 386,735 options with an intrinsic value of $917 are exercisable. No share options were exercised in 2011 or 2010. The intrinsic value of the 2,487,104 options as at December 31, 2011 was $4,134.

PERFORMANCE SHARE UNITS

In October 2011, APUC issued 28,370 performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. At the end of the three-year performance periods, the number of shares vested can range from 0% to 144% of the number of PSUs granted. Dividends accumulate during vesting period and are converted to PSUs based on the market value of the shares on that date. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

DIRECTORS DEFERRED SHARE UNITS

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one APUC common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period.

As at December 31, 2011, no DSUs had been issued.

EMPLOYEE SHARE PURCHASE PLAN

In September 2011, APUC approved an employee share purchase plan ("ESPP"). Eligible employees may have a portion of their earnings withheld to be used to purchase common shares of APUC. APUC will match up to 20% of an employee's contribution amount for the first $5,000 contributed annually and 10% of an employee's contribution amount for contributions over $5,000 and up to $10,000 annually. Shares purchased through the APUC match portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at December 31, 2011, a total of 7,176 shares had been issued under the ESPP. For the three and twelve month period ended December 31, 2011, APUC recorded $9 in compensation expense.

DIVIDEND REINVESTMENT PLAN

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the "Reinvestment Plan") which will be offered to registered holders of shares ("Shareholders") of APUC.

The purpose of the Reinvestment Plan is to enable Shareholders to invest all cash dividends on Shares in additional shares of APUC ("Plan Shares"). All such Plan Shares will be, at APUC's election, either (i) Shares purchased on the open market through the facilities of the TSX ("Market Purchase") or (ii) newly issued Shares purchased from APUC ("Treasury Purchase").

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the Agent for all Plan Shares purchased in respect of a Dividend Payment Date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Shares of APUC on TSX for the five (5) trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC's election. No commissions, service charges or brokerage fees are payable by Shareholders in connection with the Reinvestment Plan.

As at December 31, 2011, 23.6 million common shares had been registered with the Reinvestment Plan.

MANAGEMENT OF CAPITAL STRUCTURE

APUC views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

- Certain executives of APUC are shareholders of Algonquin Power Management Inc. (APMI), the former manager of APCo. A member of the Board of Directors of APUC is an executive at Emera.
- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and twelve months ended December 31, 2011 were $82 and $327, respectively (2010 - $82 and $327). Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when

flying the aircraft. During the three and twelve months ended December 31, 2011, APUC incurred costs in connection with the use of the aircraft of $103 and $453, respectively (2010 - $60 and $430) and amortization expense related to the advance against expense reimbursements of $69 and $274, respectively (2010 - $13 and $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a five year period commencing two years after the commercial operation date of the facility of June 17, 2006, increasing by 2.5% every 5 years to a maximum of 10%. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $106 and $314 for the three and twelve months ended December 31, 2011 (2010 - $77 and $266).
- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.
- Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") an entity where Senior Executives hold equity interests. APUC and APS had agreed to provide some transition services to each other until December 31, 2011. This agreement has been extended for an additional year in relation to one of the hydroelectric generating facilities. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.
- As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.
- A contract with a subsidiary of Emera to purchase energy on ISO NE and provide scheduling services on ISO NE was included as part of the acquisition of AES associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of AES. In this capacity, APUC paid a subsidiary of Emera an amount of $0 (2010 - $0 and $1,368) during the three and twelve months ended December 31, 2011 which was included as an operating expense on the consolidated statement of operations.
- In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2011 APUC paid U.S. $73 and $260 (2010 - $64 and $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.
- On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). During the three and twelve months ended December 31, 2011, AES sold electricity to MPS amounting to $1,263 and $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.
- In 2008, APUC entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and APUC issued equity to the Highground shareholders and CJIG, in exchange for $26.2 million cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

- As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of the costs related to the California Utility.
- Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.
- APUC believes that the transactions noted above were in accordance with normal commercial terms. The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Business Associations with APMI and Senior Executives.

There have been a number of business relationships between Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates (collectively the "Parties") and APUC. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. In 2011, the Board conducted a process to review all of the remaining business associations with the Parties in order to reduce, streamline and simplify these relationships. The Board formed a special committee and engaged independent consultants to assist with this process.

The co-owned assets and remaining business associations as at December 31, 2011 are listed below. Subsequent to December 31, 2011, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "Agreement"). A more detailed description of the Agreement has been set out below in *Settlement of Other Business Associations*.

i) *Rattlebrook hydroelectric generating facility*

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 27.5% by Senior Executives and the remaining percentage by third parties. This relationship was addressed pursuant to the Agreement. See *Settlement of Other Business Associations* below for more details.

ii) *St. Leon wind power generating facility*

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives. APUC and the Class B unit holders have simplified the relationship by amalgamating the previous partnership agreement and two amending agreements into an amended and restated agreement. In addition, APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

iii) *Brampton Cogeneration Inc.*

BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $100 in relation to the development of this project. In 2008, APUC accrued $100 as an estimate of the final fee owed to APMI. This relationship and corresponding liability was addressed pursuant to the Agreement.

iv) *Long Sault Rapids hydroelectric generating facility*

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the equity cash flows commencing in 2014. This relationship was addressed pursuant to the Agreement.

v) *Chartered aircraft*

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2011, $279 of the advance remained. The Board has undertaken an independent review of the relationship and believes that continuing the original arrangement is beneficial to the company. The current arrangement is expected to end in approximately 2016 when the advance will be fully utilized.

vi) *Office lease*

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The original lease was due to expire in December 31, 2012. Effective April 1, 2011, a subsidiary of APUC leased its head office facilities from a third party in a new stand alone building immediately adjacent to APUC's head office for a term of 5 years ending December 31, 2015 with an additional 5 year renewal option. APUC has amended its lease at its existing premises to be co-terminus with its subsidiary's new lease. The majority of terms in the amended lease are identical. Based on a review of the real estate leasing market in the fall of 2010, APUC believes the amended lease is on terms equivalent to fair market value for prime office space of similar size and quality.

vii) *Operations services*

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by an affiliate of APMI. APUC and the APMI affiliate had agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit. APUC agreed to provide supervisory management on a cost recovery basis for one of the facilities until December 31, 2012 to provide sufficient time for APMI to make alternative arrangements to manage the facility.

viii) *Sanger construction management*

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI. This liability was settled pursuant to the Agreement.

ix) *Clean Power Income Fund*

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund ("Clean Power") to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of December 31, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet. This liability was settled pursuant to the Agreement.

x) *Red Lily I*

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. APUC has acquired APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility. This liability was settled pursuant to the Agreement.

xi) *Trafalgar*

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar was previously awarded a U.S. $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was reached in 2004 between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal fees, third party costs and other liabilities with the proceeds from the lawsuits being shared after reimbursement of legal fees, third party costs and other liabilities. The Board has determined that any proceeds from the lawsuit will be shared between APMI and APUC proportionally to the quantum of such costs funded by each party. The Second Circuit Court of Appeals dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

Settlement of Other Business Associations.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

Under this term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including Sanger repowering project, the offer to acquire Clean Power and the development of the Red Lily I wind project.

The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the Rattlebrook and Long Sault Rapids facilities, provide a valuation of these assets and to provide advice to APUC in respect thereof.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, any credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 55% of EBITDA in 2012 and 65% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $5.4 million ($0.05 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

Market price risk

The majority of APCo's electricity generating facilities sell their output pursuant to long-term PPAs. However, certain of APCo's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each $10.00 per MW-hr change in the market prices in the New England and New York regions would result in a change in revenue of $1.0 million on an annualized basis.

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables, net receivable and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APUC does not believe this risk to be significant as approximately 82% of APCo Renewable Energy division's revenue, approximately 48% of APCo Thermal Energy division's revenue, and over 68% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	23,200	26%
Manitoba Hydro	AA	22,400	25%
Ontario Electricity Financial Corporation	A+	11,000	12%
MPS**	BBB+	6,600	7%
TransAlta Corp – Dickson Dam	BBB	4,000	5%
Public Service Company of New Hampshire	BBB	3,200	4%
National Grid	A-	3,000	3%
Total		**$ 73,400**	**82%**
Thermal Energy Division			
Regional Municipality of Peel	AAA	16,400	25%
Pacific Gas and Electric Company	BBB+	14,600	23%
Total		**$ 31,000**	**48%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2012.
** MPS is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. In this regard, the credit risk related to Liberty Utilities (South) accounts receivable balances of U.S. $5.1 million is spread over approximately 76,000 customers, resulting in an average outstanding balance of approximately $70.00 per customer. Liberty Utilities (West) has accounts receivable balances of U.S. $14.2 million with over 50% of revenue generated by residential customers.

Interest rate risk

APCo has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- The Facility has no amounts outstanding as at December 31, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- APCo's project debt at the St. Leon facility had a balance of $67.8 million as at June 30, 2011. The outstanding balance was repaid during the quarter ended September 30, 2011 using proceeds from the Senior Unsecured Debenture offering. Accordingly there is no further interest rate risk associated with this debt facility.

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2011. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.
- APCo's project debt at Long Sault, Chute Ford and its $135 million senior unsecured debentures bear fixed rates of interest and are not subject to interest rate risk.

Liberty Utilities (South)'s project debt at the Litchfield and Bella Vista Facilities are subject to a fixed rate of interest and thus are not subject to interest rate risk. Liberty Utilities (South)'s U.S. $50 million senior unsecured notes have a term of 10 years, a fixed rate of interest at 5.6% and are not subject to interest rate risk.

Liberty Utilities (West)'s U.S. $70 million senior unsecured private debt placement at the California Utility is split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes. As such these notes are not subject to interest rate risk.

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

APUC currently pays a dividend of $0.28 per share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensure APUC's long-term success. Based on the level of dividends paid during the year ended December 31, 2011, cash provided by operating activities exceeded dividends declared by 2.1 times.

As at December 31, 2011, APUC had cash on hand of $72.9 million and $80.4 million available to be drawn on the Facility. APUC reduced its level of short-term borrowings through the renewal of the Facility on February 14, 2011 for a three year term and through a U.S. $50 million private placement debt financing at Liberty Utility (South) on December 22, 2010. On July 25, 2011, APCo completed a private placement offering of the Senior Unsecured Debentures with a principal amount of $135 million. Net proceeds from the debentures were used to repay the project debt on APCo's AirSource senior debt financing which would have matured on October 2011, and to reduce amounts outstanding under APCo's senior credit facility. See the *Liquidity and Capital Reserves* section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facility.

The long term portion of Facility and project specific debt total approximately $331.1 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million on an annual basis.

- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $1.4 million on an annual basis.
- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million.
- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 130,000 MW-hrs in fiscal 2012. While the Tinker facility is expected to provide the majority of the energy required to service these customers, AES anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that AES was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $1.3 million on an annualized basis.

  This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 70,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. $50 per MW-hr. The mark-to-market value of these forward energy purchase contracts at December 31, 2011 was a net liability of U.S. $1.2 million.

Liberty Utilities is exposed to energy price risk in its Liberty Utilities (West) region which is mitigated through certain regulatory constructs. Liberty Utilities (West) provides electric service to the Lake Tahoe basin and surrounding areas at rates approved by the CPUC. The utility purchases the energy requirements for its customers from NV Energy at rates reflecting NV Energy's system average costs. In the event that these rates change, each $10.00 change per MWhr would result in a change in expense of approximately U.S. $6.5 million on an annualized basis.

The rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance, including carrying charges, does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to the California Utility's approved rates (including carrying charges associated therewith), substantially eliminating the commodity risk associated with the purchase of power.

OPERATIONAL RISK MANAGEMENT

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter. A more detailed assessment of APUC's business risks is also set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property. The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

These risks are mitigated through the diversification of APUC's operations, both operationally (APCo and Liberty Utilities) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, APCo's existing long term PPAs minimize the risk of reductions in average energy pricing.

Regulatory Risk

Profitability of APUC businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some APCo hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

Liberty Utilities' facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Liberty Utilities, and while Liberty Utilities believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Liberty Utilities regularly works with its governing authorities to manage the affairs of the business.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

Liberty Utilities' facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its consolidated financial statements as at December 31, 2011.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

Liberty Utilities faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2011.

Cycles and Seasonality

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

At Liberty Utilities (South), demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

For Liberty Utilities (West), demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Liberty Utilities (West) provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

Litigation risks and other contingencies

APUC and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

APCo owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. For additional comments on this matter, see *"Business Associations with APMI and Senior Executives - Trafalgar"*.

On December 19, 1996, the Attorney General of Québec ("Québec AG") filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management. The water lease contains a "hold harmless" clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and Seaway Management (the "Federal Authorities") into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $4.8 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, APCo accrued $1.0 million of water lease owed to Québec AG for 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $0.3 million were also recorded in 2011.

Obligations to serve

Liberty Utilities may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Liberty Utilities may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

Disclosure Controls

At the end of the fiscal year ended December 31, 2011, APUC carried out an evaluation, under the supervision of and with the participation of the APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a - 15(e) and Rule 15d - 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2011, APUC's disclosure controls and procedures are effective.

Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2011 based on the criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2011.

During the year ended December 31, 2011, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. There was no significant impact of the transition to U.S. GAAP on APUC's internal controls, information technology systems and financial reporting expertise requirements. No financial covenants were impacted by APUC's conversion to U.S. GAAP.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2011.

Millions of dollars (except per share amounts)	1st Quarter 2011	2nd Quarter 2011	3rd Quarter 2011	4th Quarter 2011
Revenue	$ 71.7	$ 66.8	$ 66.0	$ 72.1
Net earnings /(loss)	5.0	7.3	19.6	(8.5)
Net earnings / (loss) per share	0.05	0.07	0.16	(0.07)
Total Assets	1,175.8	1,177.7	1,263.1	1,282.6
Long term debt*	461.0	530.0	558.9	463.8
Dividend declared per share	0.065	0.065	0.07	0.07
	1st Quarter 2010*	**2nd Quarter 2010***	**3rd Quarter 2010***	**4th Quarter 2010**
Revenue	$ 45.9	$ 42.7	$ 45.4	$ 48.4
Net earnings / (loss)	3.5	(2.2)	1.5	15.6
Net earnings / (loss) per share	0.04	(0.02)	0.02	0.17
Total Assets	966.2	983.2	969.4	1,016.9
Long term debt*	434.0	446.7	452.8	450.8
Dividend declared per share	0.06	0.06	0.06	0.06

* Long term debt includes long term liabilities, the Facility, convertible debentures and other long term obligations

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $42.7 million and $72.1 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of $19.6 million and a net loss of $8.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Critical Accounting Estimates and Polices

The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue and fair value of derivatives. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated useful lives and recoverability of Long-Lived Assets and Intangibles

The provisions for depreciation of utility property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets (3 to 75 years). Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives (3 to 60 years) of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of APUC's assets and result in an impairment charge.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to Liberty Utilities' operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or write down. At December 31, 2011, APUC had recorded regulatory assets of $5.0 million and regulatory liabilities of $21.7 million.

Unbilled Energy Revenues

Revenues related to electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings. Historically, any differences between the actual and estimated amounts have been immaterial.

Derivatives

APUC uses derivative instruments to manage exposure to changes in electricity prices and interest rates. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value, with changes in the derivative's fair value recognized currently in earnings. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations.

Additional disclosure of APUC's critical accounting estimates is also available SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Changes in Accounting Policies

Accounting Framework

The Consolidated Financial Statements and accompanying notes have been prepared in accordance with U.S generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required per Regulation S-X provided by the Securities and Exchange Commission ("SEC") Guidance. These are APUC's first U.S. GAAP annual consolidated financial statements.

APUC's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the annual consolidated financial statements for the year ended December 31, 2010. Descriptions of the effect of the transition from Canadian GAAP to U.S. GAAP on APUC's financial position, financial performance and cash flows as at and for the two years ended December 31, 2010 are provided in note 24 of the consolidated financial statements for the year ended December 31, 2010. The accounting policies set out in the annual Consolidated Financial Statements for the year ended December 31, 2011 have been consistently applied to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

APUC has retrospectively adopted U.S. GAAP as its financial reporting accounting framework starting in 2011. U.S. GAAP reporting is permitted by Canadian securities laws and for companies listed on the TSX which are subject to reporting obligations under U.S. securities laws as an alternative to adoption of International Financial Reporting Standards ("IFRS"). APUC has concluded that U.S. GAAP is the accounting framework that provides its shareholders and other readers of its financial statements the most useful and relevant basis for financial reporting given the significance of its rate regulated businesses. U.S. GAAP includes accounting standards for rate-regulated activities within the financial statements. Except where otherwise indicated, comparative amounts in this MD&A have been restated from the amounts previously reported under Canadian GAAP.

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Section 5: EX-99.4 (REPORT OF KPMG LLP, CHARTERED ACCOUNTANTS)

Exhibit 99.4

KPMG LLP
Chartered Accountants
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, Ontario M5H 2S5
Canada

Telephone (416) 777-8500
Fax (416) 777-8818
Internet www.kpmg.ca

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), equity, and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2011 and December 31, 2010, and its consolidated results of operations and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010, in accordance with U.S. generally accepted accounting principles**.**

Other Matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 21, 2012 expressed an unmodified (unqualified) opinion on the effectiveness of Algonquin Power & Utilities Corp.'s internal control over financial reporting.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

KPMG LLP
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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Algonquin Power & Utilities Corp.

We have audited Algonquin Power & Utilities Corp.'s internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Algonquin Power & Utilities Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in management's report on internal control over financial reporting in the annual report on Form 40-F. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Algonquin Power & Utilities Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Algonquin Power & Utilities Corp. as of December 31, 2011 and December 31, 2010, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for the years ended December 31, 2011 and December 31, 2010, and our report dated March 21, 2012 expressed an unqualified (unmodified) opinion on those consolidated financial statements.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

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Section 6: EX-99.5 (CONSENT LETTER FROM KPMG LLP, CHARTERED ACCOUNTANTS)

Exhibit 99.5

KPMG LLP
Chartered Accountants
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, Ontario M5H 2S5
Canada

Telephone (416) 777-8500
Fax (416) 777-8818
Internet www.kpmg.ca

Consent of Independent Registered Public Accounting Firm

We consent to the inclusion in this annual report on Form 40-F of:

- our Independent Auditors' Report dated March 21, 2012 on the consolidated financial statements of Algonquin Power & Utilities Corp. ("the Company"), which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information;
- our Independent Auditors' Report of Registered Public Accounting Firm dated March 21, 2012 on the consolidated financial statements of the Company, which comprise the consolidated balance sheets as at December 31, 2011 and 2010, the consolidated statements of operations, comprehensive income (loss), equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information; and,
- our Report of Independent Registered Public Accounting Firm dated March 21, 2012 on the Company's internal control over financial reporting as of December 31, 2011

each of which is contained in this annual report on Form 40-F of the Company for the fiscal year ended December 31, 2011.

/s/ KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
March 30, 2012

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Section 7: EX-99.6 (CERTIFICATIONS OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 302)

Exhibit 99.6

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, Ian E. Robertson, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15 (e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 30, 2012	By:	/s/ Ian E. Robertson
	Name:	Ian E. Robertson
	Title:	Chief Executive Officer

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Section 8: EX-99.7 (CERTIFICATIONS OF CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 302)

Exhibit 99.7

CERTIFICATION PURSUANT TO SECTION 302 OF THE U.S. SARBANES-OXLEY ACT OF 2002

I, David Bronicheski, certify that:

1. I have reviewed this annual report on Form 40-F of Algonquin Power & Utilities Corp.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15 (e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 30, 2012	By:	/s/ David Bronicheski
	Name:	David Bronicheski
	Title:	Chief Financial Officer

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Section 9: EX-99.8 (CERTIFICATIONS OF CHIEF EXECUTIVE OFFICER PURSUANT TO SECTION 906)

Exhibit 99.8

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the "Corporation") on Form 40-F for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ian E. Robertson, Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 30, 2012	By:	/s/ Ian E. Robertson
	Name:	Ian E. Robertson
	Title:	Chief Executive Officer

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Section 10: EX-99.9 (CERTIFICATIONS OF CHIEF FINANCIAL OFFICER PURSUANT TO SECTION 906)

Exhibit 99.9

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Algonquin Power & Utilities Corp. (the “Corporation”) on Form 40-F for the year ended December 31, 2011 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David Bronicheski, Chief Financial Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

Date: March 30, 2012	By:	/s/ David Bronicheski
	Name:	David Bronicheski
	Title:	Chief Financial Officer

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Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.11) Detailed list of all membership fees, dues, donations, for the test year charged above the line showing the trade, technical, and professional associations and organizations and amount;

See Puc 1604.01(a) (26).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.12) A list of any management audit and depreciation studies performed within the last 5 years, specifying whether same are on file with the commission;

Algonquin Power & Utilities Corp.does not have any management audits. We have audited financial statements which are filed on sedar www.sedar.com under public companies - under Algonquin Power & Utiliites Corp. APUC does not conduct any depreciation studies.

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.13) Copies of any audits or studies referred to in (25.12) above which the utility has not submitted to the commission;

See Puc 1604.01(a) (25.12).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

REDACTED

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.14) List of officers and director of the utility and their compensation for the last 2 years;

The list below identifies the members of the Board of Directors of Algonquin Power & Utilities Corp. and their total annual compensation for service on the Algonquin Power & Utilities Corp. Board of Directors for the past two years:

	2011		2012	
	Compensation	Common Stock	Compensation	Common Stock
Christopher J. Ball(1)(2)	108,250	Nil	109,000	Nil
Kenneth Moore(1)(2)	150,000	Nil	150,000	Nil
George L. Steeves(1)(2)	117,750	Nil	99,000	Nil
Christopher Huskilson	98,250	Nil	87,000	Nil
David Bronicheski(3)	N/A	N/A	N/A	N/A
Christopher K. Jarratt(4)	Nil	Nil	Nil	Nil
Ian E. Robertson(4)	Nil	Nil	Nil	Nil
Linda Bearisto(5)	N/A	N/A	N/A	N/A

(1) Compensation is a combination of cash compensation and compensation through the issuance of Director Share Units (DSUs). Directors make an election annually regarding the percentage of total compensation to be paid in DSUs.
(2) Chris Ball holds a total of 11,238 DSUs, Ken Moore holds a total of 26,078 DSUs, George Steeves holds a total of 12,855 DSUs.
(3) David Bronicheski is not a member of the Board of Directors
(4) Christopher Jarratt and Ian Robertson are considered management of APUC and therefore do not receive remuneration as members of the Board of Directors
(5) Linda Beairsto acts only as the Board secretary and does not receive remuneration as she is a member of the management team.

The following table lists the total annual compensation for the officers of Algonquin Power & Utilities Corp. for the past two years.

	2011			2012		
	Base Salary	Incentive Pay	Restricted Stock	Base Salary	Incentive Pay(1)	Restricted Stock
Ian E. Robertson, President & Chief Executive Officer	290,700	213,849.00	Nil	419,430	349,508	Nil
Christopher K. Jarratt, Vice Chairman	290,700	167,919.00	Nil	360,280	280,488.00	Nil
David Bronicheski, Chief Financial Officer	229,500	88,061.00	Nil	258,100	158,503.00	Nil
Linda Beairsto, Secretary	Redacted	Redacted	Nil	Redacted	Redacted	Nil

Note: The Incentive pay above was paid out in the year indicated, however it reflects incentive pay earned on performance in the previous year.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.15) Lists of the amount of voting stock of the utility categorized as follows:

a. Owned by an officer or director individually;
b. Owned by the spouse or minor child of an officer or director; or
c. Controlled by the officer or director directly or indirectly;

See Puc 1604.01(a) (25.10).

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.16) A list of all payments to individuals or corporations for contractual services in the test year with a description of the purpose of the contractual services, as follows:

a. For utilities with less than $50,000 in annual revenues, a list of all payments in excess of $10,000;
b. For utilities with annual revenues in excess of $50,000, a list of all payments in excess of $50,000;

See Puc 1604.01(a) (26).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.17) For non-utility operations, the amount of assets and costs allocated thereto and justification for such allocations;

See Puc 1604.01(a) (26).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.18) Balance sheets and income statements for the previous 3 years;

See Puc 1604.01(a) (25.02).

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.19) Quarterly income statements for the previous 5 years;

Audited financial statements are filed at www.sedar.com under public companies - under Algonquin Power & Utilities Corp.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.20) Quarterly sales volumes for the previous 5 years, itemized for residential and other classifications of service;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.21) A description of the utility's projected need for external capital for the 2 year period immediately following the test year;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.22) The utility's capital budget with a statement of the source and uses of funds for the 2 years immediately subsequent to the test year;

Waiver requested

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

(25.23) The provisions of any sinking funds associated with senior capital and a description of the rate at which any respective issues of senior capital will be retired, consistent with such sinking fund(s);

There are no sinking funds associated with senior capital for Algonquin Power & Utilities Corp.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(25) If a utility is a subsidiary, duplicates of all items required by this section for the parent company except as provided in (26) below;

> (25.24) If the short-term debt component of total invested capital is volatile, the amount outstanding, on a monthly basis, during the test year, for each short-term indebtedness;

Algonquin Power & Utilities Corp. has no short-term debt.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(26) As to a subsidiary as referred to in (25) above, in lieu of duplicate copies of documentation required by Puc 1604.01(a) (5), (6), (11), (16), and (17), a certificate of an appropriate official of the subsidiary detailing any expense of the parent company which was included in the subsidiary's cost of service;

See attached attestation.

Granite State Electric Company
d/b/a Liberty Utilities
Docket No. DE 13-063
1604.01(a)(26);1604.04

Attestation

I affirm, based on my personal knowledge, information and belief that: (1) the cost and revenue statements and the supporting data submitted, which purport to reflect the books and records of Granite State Electric Company d/b/a Liberty Utilities (the "Company"), do in fact set forth the results shown by such books and records and that all differences between the books and the test year data and any changes in the manner of recording an item on the utility's books during the test year have been expressly noted; and (2) the proper amounts have been allocated to the Company from its parent and that those amounts have been included in the Company's cost of service.

March 20, 2013

Linda Doering

Linda Doering
Director of Finance
Liberty Energy Utilities (New Hampshire) Corp.

I, Linda Doering, Director of Finance, Liberty Energy Utilities (New Hampshire) Corp., being first duly sworn, hereby depose and say that I have read the foregoing Attestation and the facts alleged therein are true to the best of my knowledge and belief.

Dated: March 20, 2013

STATE OF NEW HAMPSHIRE
COUNTY OF ROCKINGHAM

Sworn to and subscribed before me this 20 day of March, 2013.

Notary Public

SARAH B. KNOWLTON, Notary Public
My Commission Expires May 11, 2016

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(27) For gas utilities, as defined in Puc 500, and for electric utilities, as defined in Puc 300, the uniform statistical report to the American Gas Association-Edison Electric Institute for the last 2 years; and

Granite State Electric Company did not file a statistical report with EEI during the last 2 years.

Granite State Electric Company d/b/a Liberty Utilities
DE 13-063

Rate Case Filing Requirements
Pursuant to PUC 1604.01(a)

(28) Support for figures appearing on written testimony and/or in accompanying exhibits.

Please refer to the attachments accompanying the testimony presented in this filing.