STATE OF NEW HAMPSHIRE
Department of Energy
Intra-Department Communication

DATE: October 25, 2023

FROM: Enforcement Division Audit Staff

SUBJECT: Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
DE 23-039 – Test Year 12/31/2022
FINAL Audit Report

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Introduction

On March 29, 2023, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (GSE, Company) filed a notice of intent to file rate schedules. The noticed rate filing schedules were provided to the Public Utilities Commission and the Department of Energy on April 28, 2023. The Department of Energy filed a motion to dismiss the rate filing on the same day, due to the lack of a 2022 FERC Form 1. The PUC granted the motion via Order 26,814, May 2, 2023, which dismissed the filing without prejudice, but allowed the docket to remain open.

Liberty filed the calendar year 2022 FERC Form 1 on May 5, 2023, the same day that a complete rate case filing was submitted to the PUC.

The audit work began on May 26, 2023. While Audit appreciates the help of Liberty's Regulatory and Accounting staff, we were unable to efficiently complete our work due to the significant timing delays between asking questions of Liberty and receiving responses. Over the course of the audit, we asked 115 specific questions. Complete responses took from one week to five weeks for the Company to provide.

One question relating to a tariff test (refer to the *Revenue* portion of this report) was originally asked on July 25, 2023, and was completely answered October 10, 2023, 77 days after the initial documentation request.

Audit is aware of the hundreds of data requests that were issued to Liberty throughout the course of the audit timeframe. Audit indicated to Liberty that if any question asked by Audit had been addressed in a data response, the Company could simply direct the Audit staff to that response. However, questions posed during the course of an audit are specific and detailed relating to actual accounting entries, verification of adherence to prior PUC Orders, settlement agreements, FERC uniform system of accounts, internal Company procedure manuals, etc. As a result, most of the audit work had questions outside of the scope of various data requests. However, because data requests have a required time in which to respond, often the Audit requests were last to be answered. Audit believes that the formality of responding to Audit requests lead, in part, to the delay in answering questions. This hindered our ability to complete the audit work efficiently and effectively.

Orders

Order 26,829 issued May 26, 2023 in docket DE 23-039, among other things, provided notice of the rate case adjudicative proceeding, set dates for the presentation of the rate filing and a prehearing conference, included details regarding intervention, public notice, and requiring Liberty to file all rate schedules in live Excel format with all supporting workpapers.

Order 26,849 issued June 15, 2023 in dockets DE 23-039 and DE 17-189 approved reviewing all issues related to the ongoing implementation of Liberty's battery storage pilot program initially docketed as DE 17-189.

Order 26,537 issued October 29, 2021 in docket DE 19-064 approved recovery of the 2020 investments in the Battery Pilot Program.

Base rates in effect during the test year were approved in docket DE 19-064 via Order 26,005, based on a 12/31/2018 test year. Three step adjustments were approved in the Settlement, based on assets in service as of 12/31/2019, 2020, and 2021.

Corporate Structure

As outlined within the 2022 FERC Form 1, and the 2021 FERC Form 1 page 102, the corporate structure of Liberty Utilities (Granite State Electric) Corp. a New Hampshire corporation, is:
100% owned by
Liberty Energy Utilities (New Hampshire) Corp., a Delaware corporation which is 100% owned by
Liberty Utilities Co., a Delaware corporation which is 100% owned by
Liberty Utilities (America) Holdco, Inc., a Delaware corporation which is 100% owned by
Liberty Utilities (America) Holdings, LLC, a Delaware limited liability corporation which is 100% owned by
Liberty Utilities (America) Co., a Delaware corporation which is 15.055% owned by Algonquin Power & Utilities Corporation and 84.945% owned by
Liberty Utilities (Canada) Corp., a Canada corporation which is 100% owned by
Algonquin Power & Utilities Corp., a Canada corporation which is publicly traded.

According to the FERC Form 1 for the year ended 12/31/2020, the structure reflected one ownership line differently than what is outlined above: Liberty Utilities (America) Co. was 100% owned by Liberty Utilities (Canada) Corp. Audit requested general clarification of the change, and was told: "*Liberty Utilities (Canada) Corp. is 100% directly owned by Algonquin Power & Utilities Corp. ("APUC"). Given APUC is the ultimate parent entity in the group that raises debt and equity financing to fund its various subsidiaries, APUC made direct contributions to Liberty Utilities (America) Co. to ease the additional administrative burdens associated with moving funds through the ownership chain. The change in ownership structure as stated in the Company's FERC Form 1 reflects this contribution by APUC to Liberty Utilities (America) Co.*"

Management and Structure

Liberty provides the Commission with a quarterly organizational chart, in compliance with the Commission Order 25,370 issued in the EnergyNorth docket DG11-040. Audit has reviewed the FERC Form 1 annual reports from 2012 through 2022, and notes the following with respect to the position of NH President, which has changed as follows:

President – V. DelVecchio July 2012 – December 31, 2013
President – R. Leehr January 1, 2014 – July 31, 2014
President – D. Saad August 1, 2014 – September 23, 2015
President – D. Swain September 23, 2015 – December 31, 2016
President – J. Sweeney January 1, 2017 – September 4, 2017
President – S. Fleck September 15, 2017 – June 30, 2021
President – N. Proudman June 30, 2021 - current

Affiliate Service Agreements

During the test year, the workforce in New Hampshire, for both GSE and EnergyNorth Natural Gas (ENG), were direct employees of Liberty Utilities Services Company (LUSC). Refer to the Payroll portion of this report.

A money-pool agreement was proposed by the Company, reviewed by Commission Staff, and approved by the Commission, via Secretarial Letter in docket DA 17-188. A revision to that agreement was provided to Audit. The First Amendment to Money Pool Agreement was effective 8/24/2020, between Liberty Utilities Co. (LUCo) and:

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Liberty Utilities (Granite State Electric) Corp.
Liberty Utilities (New England Natural Gas) Corp.
Liberty Utilities (Peach State Natural Gas) Corp.
Liberty Utilities (Pine Bluff Water) Corp.
And other direct and indirect subsidiaries or affiliates of LUCo

The agreement specifies that the "*daily outstanding balance of funds contributed to and lent through the Money Pool will earn interest…and bear interest at the daily average interest rate paid for funds obtained by LUCo from its commercial paper program…*"

The Amendment was filed in docket DA 17-188 on December 31, 2020, outside of the required 10 days per RSA 366:3. The Company requested approved (pursuant to RSA 366:4). The docket does not reflect any further action by the PUC.

Cost Allocation Manual (CAM)

As outlined in the CAM, version 2017, effective January 1, 2017, costs incurred at the APUC level are directly charged if possible. Costs at the Algonquin Power & Utilities Corp. (APUC) level include financial and strategic management, access to capital, corporate governance, and administration. Those costs are allocated among Liberty Power (generating facilities) and Liberty Utilities, both regulated utilities directly and Liberty Utilities Service Corp.

Algonquin Power & Utilities Corp (APUC)

Allocation methodologies applied to the specified indirect costs are allocated at noted percentages based on the types of costs identified:

Table 1 of the APUC Summary of Corporate Allocation Method of APUC Indirect Costs:

Type of Cost	# of Employees	Net Plant	O&M	Revenue
Legal	33%	33%	33%	not applicable
Tax Services		33%	33%	33%
Audit		33%	33%	33%
Investor Relations		33%	33%	33%
Director Fees/Insurance		33%	33%	33%
Licenses, Fees, Permits		33%	33%	33%
Escrow and Transfer Agent Fees		33%	33%	33%
Other Professional Services		33%	33%	33%
Other Administration Costs		50% Oakville Employees		50% Total Employees
Executive and Strategic Management		50% Oakville Employees		50% Total Employees

Liberty Utilities (Canada) Corp. (LUC)

Costs at the LUC level include executive, regulatory strategy, energy, page procurement, operations, utility planning, administration, and customer experience. Costs at this level provide standardization across the Liberty Utilities' regulated companies, and are allocated based on a four factor allocation. The factors are customer count 40%, utility net plant 20%, non-labor expenses 20% and labor expenses 20%.

During the test year, the (rounded) factors were:

	4/2022 – 3/2023
Liberty Water (AZ)	05.88%
Liberty Water (TX)	00.86%
Calpeco	06.46%
Granite State	**04.40%**
EnergyNorth	**09.72%**
Midstates Gas	06.04%
Midstates Water	00.72%
Arkansas	01.46%

Woodson Hensley	00.04%
Georgia	04.71%
New England Gas	05.15%
Whitehall-Water	00.14%
Whitehall-Sewer	00.15%
Parkwater	04.52%
Empire	34.65%
New Brunswick Gas	01.99%
St. Lawrence Gas	02.06%
Tinker Transmission	00.09%
New York Water	10.96%
	100.0%

Overhead/Burden Rate

Audit requested the overhead/burden rate in place for the test year and was provided with the methodology, based on budgets for 2022. The rates were calculated for January 2022:

Service Billings	**2022 Budgeted Costs**	**2022**	**% of Total**	**% of Payroll**	**Source File**
X	Rent	403,188	1.03%	0.01	2022 Clarity Budget and Lease
X	IT-related costs	3,579,924	9.18%	0.11	2022 Clarity Budget
X	IT Software Depreciation	1,077,798	2.76%	0.03	2022 IT software calculation
X	Property insurance and injuries and damages	4,396,680	11.27%	0.14	2022 Budget
X	Pensions/OPEB (all costs) and Benefits	12,187,441	31.25%	0.38	2022 Budget and actuarial data
X	TNW	4,674,864	11.99%	0.15	2022 Payroll File and Budget Submissions
X	Incentive Awards @ target	3,052,711	7.83%	0.10	2022 Budget Template
X	Payroll Taxes	2,995,757	7.68%	0.09	2022 Budget
X	Back Office: Labor	2,542,288	6.52%	0.08	2022 Budget Template
X	Finance: Non-Labor	344,828	0.88%	0.01	2022 Budget
X	HR: Non-Labor	279,271	0.72%	0.01	2022 Budget
X	Regulatory: Non-Labor	133,447	0.34%	0.00	2022 Budget
X	Legal: Non-Labor	77,370	0.20%	0.00	2022 Budget
X	Executive: Non-Labor	165,210	0.42%	0.01	2022 Budget
X	EHS: Non-Labor	314,492	0.81%	0.01	2022 Budget
X	Procurement: Non-Labor	1,516,218	3.89%	0.05	2022 Budget
X	Electric Ops: Non-Labor	84,200	0.22%	0.00	2022 Budget
X	Gas Ops: Non-labor	93,329	0.24%	0.00	2022 Budget
X	Dispatch, Control & Production: Non-labor	471,659	1.21%	0.01	2022 Budget
X	Engineering: Non-labor	611,403	1.57%	0.02	2022 Budget
	Total Costs	39,002,079	100.00%	1.2236	
	Total 2022 Budgeted payroll (Excludes Incentives/TNW/Back Office Labor)	31,873,988			
	Overhead/Burden For Service Billings - 8810	122.4%			

The burden calculation is then split between GSE and ENG:

	GSE 30%		ENG 70%	
X	89,553	0.8%	313,635	1.5%
X	1,261,898	11.2%	2,318,027	11.2%
X	360,253	3.2%	717,544	3.5%
X	2,646,531	23.5%	1,750,149	8.5%
X	4,510,070	40.1%	7,677,371	37.2%
X	1,402,459	12.5%	3,272,404	15.9%
X	915,813	8.1%	2,136,898	10.4%
X	898,727	8.0%	2,097,030	10.2%
X	958,351	8.5%	1,583,937	7.7%
X	103,549	0.9%	241,280	1.2%
X	85,460	0.8%	193,810	0.9%
X	41,088	0.4%	92,359	0.4%
X	23,826	0.2%	53,544	0.3%
X	26,451	0.2%	138,759	0.7%
X	97,855	0.9%	216,637	1.1%
X	614,521	5.5%	901,697	4.4%
X	84,200	0.7%	-	0.0%
X	-	0.0%	93,329	0.5%
X	74,084	0.7%	397,575	1.9%
X	311,969	2.8%	299,434	1.5%
	14,506,660	128.9%	24,495,419	118.8%
Total 2022 Budgeted payroll (Excludes Bonuses and other Burden Labor)	11,252,644.48		20,622,336.71	
	GSE Burden		**ENG Burden**	
Burden Rates	**128.92%**		**118.78%**	

<u>Liberty Utilities Regional</u>

Costs at the LU Regional level are allocated based on a four factor allocation. The factors are net plant 25%, customer count 25%, expenses 25%, and labor 25%. During the test year, the (rounded) factors were:

	4/2022 – 3/2023
Liberty Water (AZ)	05.19%
Liberty Water (TX)	00.83%
Calpeco	06.74%
Granite State	**04.30%**
EnergyNorth	**09.60%**
Midstates Gas	05.40%
Midstates Water	00.67%
Arkansas	01.33%
Woodson Hensley	00.03%
Georgia	04.24%
New England Gas	04.90%
Whitehall-Water	00.13%
Whitehall-Sewer	00.14%
Parkwater	04.33%
Empire	37.47%
New Brunswick Gas	02.17%
St. Lawrence Gas	02.10%
Tinker Transmission	00.11%
New York Water	10.34%
	100.02%

Corporate Internal Audit

Audit requested the Algonquin Internal Audit staff report or opinion relative to the calculation of overheads. The Company indicated that the Internal Audit staff, as well as the External auditors, review the calculations, but do not issue reports or opinions exclusively related to overheads.

External Audits

The Company included financial audit results for the years ending 12/31/2021 and 12/31/2022 as conducted by Ernst and Young, within the filing Puc1604.01(a)(13), Bates pages I-113 through I-136.

Customer Information System and General Ledger

Effective October 1, 2022, the Company converted from the Great Plains (GP) software system to SAP and Power Plan. The change impacted all aspects of the utility's business, from customer service, to accounting for Plant through use of Power Plan, to recording of financial entries in its general ledger. Audit verified the roll-forward of the September 30, 2022 account balances within each GP general ledger account into the SAP system.

Audit was informed that the functionality of SAP is:

"*The job system in SAP is known as WBS elements (Work Breakdown Structure). These are used to record and track expenses to specific areas of the business: Capital, Intercompany, and Operations and Maintenance. The process that does this is called settlements. In this process, WBS activities are reflected in 7xxxxx and 8xxxxx natural GL accounts and* *allocated to be reflected in income statement or balance sheet accounts. Once the settlements are run, each WBS should be zero. When a WBS is not zero it means a transaction, while in the GL, did not "settle" where it needed to be reflected. This could be either a coding issue or* a timing *issue."*

"For Granite State and EnergyNorth: The conversion from GP to SAP and Power Plan has resulted in some amounts being reflected under similar categories in Power Plan but not in the GL. $133,283.70 is reflected under account 122 (accumulated provision for depreciation and amortization of nonutility property) in the GL but in Power Plan, it is reflected under account 108 (accumulated provision for depreciation of electric utility plant) because they are both depreciation accounts. The $638,242.47 is Cost of Removal which is reflected under account 242 (miscellaneous current and accrued liabilities) in the GL but in PowerPlan, it is included in account 108 (accumulated provision for depreciation of electric utility plant). The ($146,846.47) and ($240,117.15) seem to be settlement errors as discussed above. At year-end these amounts were reconciling items between the GL and the Power Plan subledger. These amounts have since settled properly."

Audit verified that the 472 Great Plains general ledger accounts and related September 2022 balances transferred into the 827 SAP general ledger. Incidents in which accounts on the FERC Form 1 could not be verified to the SAP related general ledger accounts are noted throughout this report. Audit was informed of specific accounts that had not been coded to the settling account correctly. **Audit Issue #1**

<u>Overview of the FERC Form 1 since the Prior Test Year</u>

Audit compiled a comparative summary of the FERC Form 1 reports from the prior test year 2018, through the current 2022 test year. The balance sheet has increased from $204,902,817 at year-end 2018 to $328,891,720 at year-end 2022, or an increase of 61%. The roll-forward of the FERC Form 1 reflects:

	FERC Form 1 12/31/2018	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	FERC Form 1 12/31/2022
Utility Plant	$ 249,231,095	$ 263,916,439	$ 281,663,336	$ 307,083,593	$ 349,877,082
Construction Work in Progress	$ 3,907,980	$ 6,022,727	$ 10,786,906	$ 17,065,613	$ 15,266,206
TOTAL Utility Plant	$ 253,139,075	$ 269,939,166	$ 292,450,242	$ 324,149,206	$ 365,143,288
(Less) Accum Provision for Dep, Amort, Depl	$ (93,623,954)	$ (99,447,339)	$ (106,237,402)	$ (114,595,819)	$ (123,090,712)
Net Utility Plant	**$ 159,515,121**	**$ 170,491,827**	**$ 186,212,840**	**$ 209,553,387**	**$ 242,052,576**
Non-utility Property (121)	**$ 32,086**	**$ 32,086**	**$ 32,086**	**$ 21,466**	**$ 21,466**
Cash (131)	$ 61,175	$ 19,277	$ 61,625	$ (2,074)	$ 43,238,110
Special Deposits (132-134)	$ 26,339	$ 26,962	$ 227,162	$ 5,227,213	$ 32,759
Customer Accounts Receivable (142)	$ 13,051,794	$ 11,815,914	$ 12,512,500	$ 14,130,627	$ 29,736,312
Other Accounts Receivable (143)	$ 107,061	$ 101,650	$ 447,842	$ (193,717)	$ 699,314
(Less) Accum. Provision for Uncollectible credit (144)	$ (818,355)	$ (710,351)	$ (752,496)	$ (734,292)	$ (970,049)
Accounts Receivable from Associated Companies (146)	$ 5,942	$ 74,112	$ 59,984	$ -	$ -
Plant Materials and Supplies (154)	$ 1,877,163	$ 2,950,132	$ 2,538,074	$ 2,400,315	$ 3,759,408
Stores Expense Undistributed (163)	$ -	$ -	$ -	$ -	$ -
Prepayments (165)	$ 1,081,231	$ 1,118,155	$ 1,401,770	$ 1,233,254	$ 1,384,677
Accrued Utility Revenues (173)	$ 1,773,168	$ 1,882,327	$ 2,170,929	$ 2,248,596	$ 3,002,394
Miscellaneous Current and Accrued Assets (174)	$ -	$ -	$ -	$ -	$ -
Total Current and Accrued Assets	**$ 17,165,518**	**$ 17,278,178**	**$ 18,667,390**	**$ 24,309,922**	**$ 80,882,925**
Unamortized Debt Expenses (181)	$ 29,711	$ 26,043	$ 22,183	$ 18,419	$ 14,655
Other Regulatory Assets (182.3)	$ 27,884,536	$ 12,105,227	$ 16,639,767	$ 16,053,793	$ 4,557,561
Preliminary Survey and Investigation Charges Electric (18:	$ 169,765	$ 125,833	$ 125,833	$ 215,709	$ 310,019
Clearing Accounts (184)	$ 106,080	$ 88,627	$ 255,483	$ 303,208	$ 1,052,518
Miscellaneous Deferred Debits (186)	$ -	$ -	$ -	$ -	
Accumulated Deferred Income Taxes (190)	$ -	$ -	$ -	$ -	
Total Deferred Debits	**$ 28,190,092**	**$ 12,345,730**	**$ 17,043,266**	**$ 16,591,129**	**$ 5,934,753**
TOTAL ASSETS	**$ 204,902,817**	**$ 200,147,821**	**$ 221,955,582**	**$ 250,475,904**	**$ 328,891,720**

	FERC Form 1 12/31/2018	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	FERC Form 1 12/31/2022
Common Stock Issued (201)	$ 6,040,000	$ 6,040,000	$ 6,040,000	$ 6,040,000	$ 6,040,000
Other Paid-in Capital (208-211)	$ 92,984,903	$ 92,984,903	$ 92,984,903	$ 92,984,903	$ 92,984,903
Retained Earnings (215, 215.1, 216)	$ 4,535,099	$ 8,750,460	$ 20,391,601	$ 32,931,729	$ 44,680,599
Accumulated Other Comprehensive Income (219)	$ 160,041	$ (452,770)	$ (3,471,446)	$ (1,201,967)	$ 3,257,743
Total Proprietary Capital	**$ 103,720,043**	**$ 107,322,593**	**$ 115,945,058**	**$ 130,754,665**	**$ 146,963,245**
Bonds (221)	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000	$ 15,000,000
Advances from Associated Companies (223)	$ 17,000,000	$ 17,000,000	$ 17,000,000	$ 17,000,000	$ 17,000,000
Total Long Term Debt	**$ 32,000,000**	**$ 32,000,000**	**$ 32,000,000**	**$ 32,000,000**	**$ 32,000,000**
Obligations Under Capital Leases-Noncurrent (227)	$ -	$ 6,280	$ 583	$ -	$ -
Accumulated Provision for Injuries and Damages (228.2)	$ 17,737	$ 11,389	$ 11,348	$ 10,998	$ 10,998
Accumulated Provision for Pensions and Benefits (228.3)	$ 14,699,662	$ 15,113,443	$ 18,485,313	$ 14,606,247	$ 7,293,207
Asset Retirement Obligations (230)	$ -	$ -	$ -	$ -	$ -
Total Other Non-current Liabilities	**$ 14,717,399**	**$ 15,131,112**	**$ 18,497,244**	**$ 14,617,245**	**$ 7,304,205**
Accounts Payable (232)	$ -	$ -	$ -	$ -	$ 4,513,650
Accounts Payable to Associated Companies (234)	$ 11,350,016	$ 12,881,528	$ 20,996,569	$ 31,963,725	$ 75,125,573
Customer Deposits (235)	$ 1,278,349	$ 1,249,583	$ 1,175,621	$ 1,206,777	$ 1,333,412
Taxes Accrued (236)	$ -	$ -	$ (186,381)	$ 2,091,467	$ 4,330,176
Interest Accrued (237)	$ 142,792	$ 142,792	$ 325,292	$ 142,792	$ 325,292
Tax Collections Payable (241)	$ 43,247	$ 32	$ 14	$ 14	$ -
Miscellaneous Current and Accrued Liabilities (242)	$ 9,841,558	$ 10,016,690	$ 9,433,247	$ 14,998,463	$ 32,120,029
Obligations Under Leases-Current (243)	$ -	$ 7,828	$ 297	$ 13,233	$ 101,750
Total Current and Accrued Liabilities	**$ 22,655,962**	**$ 24,298,453**	**$ 31,744,659**	**$ 50,416,471**	**$ 117,849,882**
Customer Advances for Construction (252)	$ -	$ -	$ -	$ -	
Other Deferred Credits (253)	$ 118,383	$ 117,897	$ 3,949,684	$ 117,127	$ 117,023
Other Regulatory Liabilities (254)	$ 21,716,340	$ 10,863,514	$ 6,194,636	$ 8,313,603	$ 6,913,697
Accumulated Deferred Income Taxes Other (283)	$ 9,974,690	$ 10,414,252	$ 13,624,301	$ 14,256,793	$ 17,743,668
Total Deferred Credits	**$ 31,809,413**	**$ 21,395,663**	**$ 23,768,621**	**$ 22,687,523**	**$ 24,774,388**
Total Liabilities and Stockholder Equity	**$ 204,902,817**	**$ 200,147,821**	**$ 221,955,582**	**$ 250,475,904**	**$ 328,891,720**

Audit calculated the annual percentage change to the balance sheet, with the following results:

2018	2019	2020	2021	2022
2%	-2%	11%	13%	31%

	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	Test Year FERC Form 1 12/31/2022	% Change from prior year end
Utility Operating Revenues (400)	$ (102,972,734)	$(104,066,200)	$ (107,899,134)	$(141,928,329)	32%
Operation Expenses (401)	$ 71,874,815	$ 68,230,338	$ 69,445,550	$ 105,270,016	52%
Maintenance Expenses (402)	$ 3,573,702	$ 3,580,477	$ 5,265,408	$ 6,165,689	17%
Depreciation Expenses (403)	$ 7,266,549	$ 8,479,102	$ 9,916,818	$ 10,429,931	5%
Depreciation Expense for Asset Retirement Costs (403.1)	$ -	$ -	$ -	$ -	#DIV/0!
Amortization/Depletion of Utility Plant (404-405)	$ 2,377,447	$ 357,131	$ 167,550	$ 529,378	216%
Regulatory Debits (407.3)	$ 5,830	$ 138,410	$ 282,538	$ 144,128	-49%
Taxes Other than Income (408.1)	$ 5,519,673	$ 5,721,390	$ 6,423,995	$ 6,549,124	2%
Income Taxes-Federal (409.1)	$ -	$ -	$ 2,091,467	$ 2,238,709	7%
Income Taxes -Other (409.1)	$ 95,000	$ 121,623	$ 819,835	$ 873,455	7%
Provision for Deferred Income Taxes (410.1)	$ 1,243,021	$ 4,215,756	$ (346,351)	$ 1,250,385	461%
(Less) Provision for Deferred Income Taxes-credit (411.1)	$ -	$ -	$ -	$ -	#DIV/0!
Investment Tax Credit Adjustment net (411.4)	$ -	$ -	$ -	$ -	#DIV/0!
Total Utility Operating Expenses	$ 91,956,037	$ 90,844,227	$ 94,066,810	$ 133,450,815	42%
NET UTILITY OPERATING INCOME (LOSS)	**$ (11,016,697)**	**$ (13,221,973)**	**$ (13,832,324)**	**$ (8,477,514)**	-39%

	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	Test Year FERC Form 1 12/31/2022	% Change from prior year end
(less) expenses of non-utility operations					
Interest and Dividend Income (419)	$ (467,804)	$ (262,376)	$ (482,430)	$ (281,962)	-42%
Allowance for Funds Used during Construction (419.1)	$ (109,324)	$ (207,168)	$ (278,305)	$ (130,600)	-53%
Miscellaneous Non-operating Income (421)	$ -	$ -	$ -	$ -	#DIV/0!
(Gain) or Loss on Disposition of Property (421.1)	$ -	$ -	$ (108,789)	$ -	-100%
Total Other Income	$ (577,128)	$ (469,544)	$ (869,524)	$ (412,562)	-53%
Donations (426.1)	$ 11,216	$ 11,240	$ 6,770	$ 18,841	178%
Life Insurance (426.2)	$ -	$ -	$ -	$ -	#DIV/0!
Penalties (426.3)	$ -	$ -	$ -	$ 1,500	#DIV/0!
Expenses for civic political & related activities (426.4)	$ 15,310	$ 9,173	$ 20,922	$ 21,690	4%
Other Deducations (426.5)	$ 4,162,570	$ (39,312)	$ 301,717	$ (201,344)	-167%
Total Other Income Deductions	$ 4,189,096	$ (18,899)	$ 329,409	$ (159,313)	-148%
Income Taxes-Federal (409.2)	$ -	$ -	$ -	$ -	#DIV/0!
Income Taxes-Other (409.2)	$ -	$ -	$ -	$ -	#DIV/0!
Provision for Deferred Income Taxes (410.2)	$ (98,010)	$ (131,940)	$ (196,020)	$ (196,020)	0%
Total Taxes on Other Income and Deductions	$ (98,010)	$ (131,940)	$ (196,020)	$ (196,020)	0%
Net Other (Income)/Loss and Deductions	**$ 3,513,958**	**$ (620,383)**	**$ (736,135)**	**$ (767,895)**	4%
Interest on Long-term Debt (427)	$ 1,130,500	$ 1,130,500	$ 1,130,500	$ 1,130,500	0%
Amortization of Debt Discount & Expense (428)	$ 2,619	$ 2,619	$ 2,619	$ 2,183	-17%
Interest on Debt to Associated Companies (430)	$ 777,839	$ 784,267	$ 777,839	$ (4,075,337)	-624%
Other Interest Expense (431)	$ 1,941,118	$ 410,972	$ 296,417	$ 518,502	75%
(Less) Allowance for Borrowed Funds Used during Cnstrctn Cr-(432)	$ (69,065)	$ (127,143)	$ (168,534)	$ (79,309)	-53%
NET Interest Charges	$ 3,783,011	$ 2,201,215	$ 2,038,841	$ (2,503,461)	-223%
NET INCOME	**$ (3,719,728)**	**$ (11,641,141)**	**$ (12,529,618)**	**$ (11,748,870)**	-6%
NET INCOME % change year to year	-20%	213%	8%	-6%	

<u>Net Plant in Service $242,052,576</u>

	FERC Form 1 12/31/2019	FERC Form 1 12/31/2020	FERC Form 1 12/31/2021	FERC Form 1 12/31/2022
Utility Plant	$ 263,916,439	$ 281,663,336	$ 307,083,593	$ 349,877,082
Construction Work in Progress	$ 6,022,727	$ 10,786,906	$ 17,065,613	$ 15,266,206
TOTAL Utility Plant	$ 269,939,166	$ 292,450,242	$ 324,149,206	$ 365,143,288
(Less) Accum Provision for Dep, Amort, Depl	$ (99,447,339)	$ (106,237,402)	$ (114,595,819)	$ (123,090,712)
Net Utility Plant	**$ 170,491,827**	**$ 186,212,840**	**$ 209,553,387**	**$ 242,052,576**

The filing schedule does not include the CWIP balance. Reported Plant in Service at 12/31/2022, per the FERC Form 1 was a net $365,143,288. The filing schedule RR-4 indicates the Accumulated Depreciation balance is $123,210,870. This is a $120,158 difference compared to the 2022 FERC Form 1. Audit requested clarification of the exclusion of accounts 15550010108100 Acc Dep-FC-Leg ($1,412.71) and 15550010108100, RWIP (Removal Work in Progress) $121570.85. The Company noted, "*The variance of $120,158 in the GL account 108 Accumulated Depreciation reported balance between FERC Form 1 and RR-4-1 is simply based on a difference in the preparation of the data for two filings.* Additional clarification was requested as to where specifically those two balances can be found within the filing. The Company stated that neither account balance was included in the revenue requirement schedules. The Company then indicated that the "*$121,571 in RWIP is Removal Work in Progress and therefore would not be included in the revenue requirement. The $1,413 in Legacy Costs represent two salvage cash payments. These amounts should have been included in the revenue requirement. They were inadvertently excluded because they were posted directly to the legacy account and therefore never settled properly through a WBS# in SAP to depreciation reports. The Company will consider this, along with any other changes identified during the discovery process, in its next update of the revenue requirement in this proceeding.*" **Audit Issue #2**

The filing schedule RR-4 reflects a total Net Utility Plant of $158,015,121. In 2022 the Company had a beginning balance of $1.5 million in the 105 Plant Held for Future Use account that during 2022 was used to develop the Rockingham Substation. The associated project is 301864, Rockingham SS Land.

On schedule RR-4 on line 14, there are $21 million in rate base offsets that are related to the DE 16-383 for regulatory reporting purposes only and in future rate cases the Company will make $21 million in ADIT adjustments to rate base in accordance with the DE 16-383 Settlement Agreement, Attachment 7 pages 13 and 47. The Company indicated the $21 million ratemaking adjustment did not have any relation to the GL.

The detailed plant in service FERC pages 204-207 sum to the $349,877,082. Page 200 reflects $340,029,912 and $9,847,170 Completed Construction not Classified. The two sum to the $349,877,082. The $21,466 Non-utility Property booked to the 121 account was not included on page 200. The balance sheet on page 110 reflects Utility Plant in Service of $242,052,576 which is the $349,877,082 plus CWIP of $15,266,206 net of accumulated depreciation $(123,090,712). The accumulated depreciation figure was noted on the FERC Form 1 page 200 as a credit on line 14.

FERC Account	2022 FERC Form 1	SAP Account	SAP GL Yr End	Variance
		1010 Plant in Service	$ 300,645,562	
		106 Com. Const Not Class	$ 49,231,519	
101-106, 114	$ 349,877,082		$ 349,877,082	
107	$ 15,266,206	107 CWIP	$ 15,258,393	$ 7,813
Total	$ 365,143,288		$ 365,135,475	

Audit reviewed the Company capital and expense policy most recently revised in July 2022. The Company expensing/capitalization procedures manual was first effective on December 31, 2013. The chart below summarizes the plant activity since the most recent rate case.

TOTAL PLANT ACTIVITY 2019 - 2022

	Beginning Bal	Additions	Retirements	Adjustments	Transfers	Ending Balance	FERC ending pg 207 ln 100
1/1/2019	$ 247,731,096	$ 17,227,348	$ (2,567,520)	$ 25,516	$ -	$ 262,416,440	$262,416,440
1/1/2020	$ 262,416,440	$ 17,534,798	$ (708,823)	$ 920,922	$ -	$ 280,163,337	$280,163,336
1/1/2021	$ 280,163,337	$ 25,979,248	$ (553,580)	$ (5,411)	$ -	$ 305,583,594	$305,583,593
1/1/2022	$ 305,583,595	$ 43,910,073	$ (1,117,090)	$ (504)	$1,501,010	$ 349,877,084	$349,877,082

Test of Additions Closed to Plant since the Prior Audit

Audit requested a listing of projects which were closed to plant in service accounts in 2019-2022. Audit reviewed a total of twelve project three for each year for 2019-2022.

Project #	Project Description	Year	Budgeted Amount	Actual Unitized Amount	Variance (Over)Under	% Variance
8830-1962	Lebanon Area Low Voltage Mitigation	2019	$ -	$ 62,902	$ (62,902)	100%
8830-1954	Install Mt. Support 16L2-16L5 Feeder Tie	2019	$ 200,000	$ 146,450	$ 53,550	-26.77%
8830-1956	Install 13L2-9L3 Feeder Tie	2019	$ 200,000	$ 246,037	$ (46,037)	23.02%
8830-2024	LED Street Light Conversion	2020	$ 200,000	$ 257,404	$ (57,404.00)	28.70%
8830-2025	IT Systems & Equipment Blanket	2020	$ 125,000	$ 47,398	$ 77,601.96	-62.08%
8830-2013	GSE-Dist-Asset Replace Blanket	2020	$ 400,000	$ 83,379	$ 316,620.94	-79.16%
8830-2127	IT Systems Allocations - Corporate	2021	$ 50,000	$ 146,636	$ (96,636.17)	193.27%
8830-2139	IE-NN URD Cable Replacement	2021	$ 500,000	$ 235,107	$ 264,893.00	-52.98%
8830-2119	IE-NN Dist Transformer upgrades	2021	$ 50,000	$ 38,828	$ 11,172.11	-22.34%
8830-2083	Inv. Mgmt Sys Imprvmnt - 10 yr	2022	$ -	$ 110,736	$ (110,736)	100.00%
8830-2241	Feeder Getaway Cable Replacement	2022	$ 250,000	$ 119,779	$ 130,221	-52.09%
8830-2210	GSE-Dist-St Light Blanket	2022	$ 125,000	$ 133,311	$ (8,311)	6.65%
		Total	$ 2,100,000	$ 1,627,968	$ 472,032	

Purchase Order and Invoice Authorization limits were requested and provided:

Level	Value	
CEO	Over 7.5 Million	
Executive VP	$	7,500,000
Senior VP	$	3,500,000
Regional President (LU)	$	3,000,000
State President, GM & VP (LU)	$	2,000,000
Vice President	$	1,000,000
Senior Director	$	500,000
Director	$	300,000
Senior Manager	$	200,000
Manager	$	100,000
Supervisor	$	10,000
Staff	TBD	

Any commitment of funds in excess of $100,000 for growth, supported, unplanned, and discretionary projects noted within the Policies and Procedures for Capital Expenditures are requirements for the following documentation:

- Business Case detailing the need, justification, and overall cost estimate for the project;
- Capital Expenditure Summary outlining the project costs;
- Spending Schedule which tracks expenses as the project progresses;
- Over-spending Request form for any overspend in excess of 10% of initial cost.
- Project Closeout detailing the final project cost details and lessons learned from the project

<u>121 Non-Utility Property $21,466</u>

In 2021 the 8830-2-0000-10-1610-1210 Non-Utility Property-Land account had a $32,086 beginning balance. The Company in July 2021 sold a portion of the land that was in Salem. The July 2021 land sale was recorded as a retirement that debited the Gain on the Disposition of Property account 8830-2-0000-40-4400-4211 for $10,620 credited the 1210 Non-Utility Property-Land account for ($10,620) that resulted in a December 2021 $21,466 account ending balance. In 2022 there was no account activity in the SAP GL account 15001010121000 that ended with the $21,466 account balance.

<u>Overheads</u>

The Company provided the 2019-2022 capitalized overhead budget calculations for the year that were used to calculate the capitalized overhead rate. The Company provided a CWIP spreadsheet that indicates the capitalized overhead costs include rent, IT, software depreciation, legal, back office, payroll taxes, incentive awards, finance, executive, procurement, health and safety, operations, dispatch, and engineering. The overhead rate is determined by dividing the budgeted costs by the total budgeted payroll that excludes the incentive and back-office payroll.

Liberty stated there is no set rate for burden allocation. Depending on the eligible burden charges in a job, the total population to be allocated, and the amount to be allocated, will determine the amount of burden for each individual job. The burden process is based on actual charges and could fluctuate from month to month depending on the level of construction. Granite State Electric used to have 13 burden identifiers that were streamlined on October 1, 2016 to 4 burden identifiers. The reason for this was to streamline and simplify the burden calculation process for the Company. As part of the review of the plant section, Audit reviewed the Stores, Corporate, LAB, BRD.

The LU corporate overhead is a percentage of direct and indirect charges that are capitalized. The corporate overhead is the capitalization of Liberty Utilities Canada, APUC, and LABS costs based on the INDOH% that is set by corporate. The Regional, US LABS, and Liberty Corporate Services are capitalized for employees located in New Hampshire only, based on percentages set by their managers. The overhead figures are reviewed annually. The eligible cost elements for corporate overhead are labor, inventory, vouchers, and outside services.

The LAB overhead is operational expenses to capitalize the labor split, bonus accrual, payroll accrual, and field labor. This is a predetermined percentage of labor spent working on capital projects that is moved into the capital accounts monthly. The percentages are set on an employee basis determined by the manager that is reviewed annually. The charges in this burden are generally for charges that cannot be charged to other individual jobs. The eligible cost elements for corporate overhead are labor, inventory, vouchers, and outside services.

The BRD overhead consists of benefits charges that are allocated to capital jobs related to labor. This is specifically the operations expenses moved to capitalized labor that is a predetermined percentage. The BRD overhead also consists of benefits charged to direct capital labor and fleet. The fleet burden charges consist of maintenance and fuel charges that are spread proportionality based on labor dollars, and inclusion of the capitalized fleet overhead, discussed below.

The Stores overhead consists of inventory storeroom costs to be allocated with eligible materials costs during a month. The charges consist of bonus accruals and the clearing of the stores account 1380-1630. The purpose of the stores account is to reclassify capital costs that should have been expensed.

The Capitalized Fleet overhead represents a portion of the monthly fleet depreciation expense, capitalized and allocated on a pro-rata basis across open Construction Work in Process (CWIP) jobs. The capitalization is the monthly depreciation expense of grouped asset 8830-3920, multiplied by the quarterly fleet depreciation rate capitalized by CWIP job through the BRD discussed above. The Company has been capitalizing fleet overhead since 2018. The Company indicated they started this because of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 360. ASC 360 relates to Generally Accepted Accounting Principles (GAAP) for property, plant, equipment and related depreciation. The Company capitalizes a portion of depreciation on construction vehicles in account #392, Transportation Equipment, and equipment in account #396, Power Operated Equipment, to FERC account 107 CWIP. The calculated depreciation is posted to regulatory accounts 55056010403000 Capitalized Equipment and 55057010403000 Capitalized Fleet. A journal entry is then done each month to move a percentage of this depreciation expense to the 107 CWIP account where these amounts are allocated across capital projects. The FERC Uniform System of Accounts did not adopt ASC

360. Audit spoke with a FERC accountant who confirmed to Audit that capitalization of standard fleet depreciation does not comply with the FERC USoA. **Audit Issue #3**

Continuing Property Records

The Company provided documentation for each work order that details when the projects were unitized, placed into service, and taken out of Construction Work in Progress. From that documentation, Audit sampled specific transactions, and the Company provided the detailed journal entries. See the review of each project/ work order further in this report that discusses when the work orders were placed into service.

Energy Assistance Program

On June 1, 2023 the DE 21-133 Energy Assistance Program Final Audit Report was issued which identified $140,000 in EAP costs the Company was authorized to recover on June 1, 2021 per Order 26,485 through the EAP/SBC funding mechanism. The Audit issue (#1) further indicates that Liberty, in the updated March 15, 2023 EAP reconciliation filing, recovered the costs associated with the required EAP technical system upgrades that was verified by Audit in the conclusion of Audit issue #1. Because the $140,000 EAP billing system upgrade costs were recovered through SBC funds, the Company is not able to add the plant additions to rate base without at least entering the reimbursement costs as a Contribution in Aide of Construction (CIAC). Since the Company was reimbursed for the upgrade, as the costs were covered by the SBC, the Company should not have left the plant additions to plant in service without a direct CIAC offset. **Audit Issue #4**

Review of Project Additions

The charts below represent the (rounded) Budgeted vs Actual for the 2019-2022 projects reviewed.

2019 Projects	Budgeted	2019 Actual Spent	Difference
8830-1932	$0	$62,902	($62,902)
8830-1954	$200,000	$146,450	$53,550
8830-1956	$200,000	$246,037	($46,037)
Total	$400,000	$455,390	($55,390)

2020 Projects	Budgeted	2020 Actual Spent	Difference
8830-2024	$200,000	$257,404	($57,404)
8830-2025	$125,000	$47,398	$77,602
8830-2013	$400,000	$83,379	$316,621
Total	$725,000	$388,181	$336,819

2021 Projects	Budgeted	2021 Actual Spent	Difference
8830-2127	$50,000	$146,636	($96,636)
8830-2139	$500,000	$235,107	$264,893
8830-2119	$50,000	$38,828	$11,172
Total	$600,000	$420,571	$184,023

2022 Projects	Budgeted	2022 Actual Spent	Difference
8830-2083	$0	$110,736	($110,736)
8830-2241	$250,000	$119,779	$130,221
8830-2210	$125,000	$133,309	($8,311)
Total	$375,000	$363,826	$11,174

Audit performed a review of the Company budgeted/actual costs and noted numerous instances of the project/work order estimate not being very accurate. The Company when asked for a reason to explain the variances indicated to review the Project Closeout Report which on most of the reports reviewed due not give a specific reason for why a project was over or under the budget that is very descriptive. **Audit Issue #5**

Review of Staff Data Request 3-1 8830 Unallocated Burden Project

Project ID	Year	Project Description	Budget	Actual	Variance ($) (over)/under	% Variance (over)/under
8830-UNALLOC OH	2019	Finance Unalloc Burden	$ -	$ 309,595	$ (309,595)	
8830-UNALLOC OH	2020	Finance Unalloc Burden	$ 384,069	$ 843,160	$ (459,091)	-120%
8830-UNALLOC OH	2021	Finance Unalloc Burden	$ 193,063	$ 631,619	$ (438,556)	-227%
8830-UNALLOC OH	2022	Finance Unalloc Burden	$ 191,500	$ 2,730,627	$ (2,539,127)	-1326%
		Total	**$ 768,632**	**$ 4,515,002**	**$ (3,746,370)**	

The response to Staff Data Request 3-1 for 2019-2022 included a project ID 8830-Unallocated Overhead/Burden. The budgeted costs were $768,632 while the actual capital spending was $4,515,002. This is a ($3,746370) over budget. The Company clarified that this project represented capital spending not a project that was unitized to plant in service. The $4,515,002 capital spending is the cost remaining at the end of a given year. The Company clarified the unallocated finance burden is a vehicle to hold CWIP costs before being allocated to actual construction/purchasing jobs.

The overhead rates are determined by forecasting the overhead cost divided by the forecasted eligible capital amount spent. The eligible capital burdens include direct labor, materials, vouchers, and outside services that was in accordance with the most recently updated January 31, 2020 New Hampshire Capital Overhead Procedure Manual. The procedure manual explains how general accounting entries for overhead are done monthly by debiting the overhead/burden and crediting the individual job based on calculated rate and eligible spending. The Company on October 1, 2022 began using SAP and since that time, labor burdens follow labor charges directly to individual projects.

<u>Projects Tested</u>
<u>2019 Projects</u>

<u>8830-1962 Lebanon Area Low Voltage Mitigation</u>

<u>Unitized in 2019 8830-1962 Lebanon Low Voltage 16L5 Feeder $62,903</u>

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$	0	
Cost Element 2-Stores and Materials	$	13,211	
Cost Element 4-Vouchers	$	4,999	
Cost Element 5-Outside Services	$	0	
Cost Element 6- Burden	$	44,693	
Cost Element 7-Cost of Removal	$	0	
Cost Element 9-AFUDC	$	0	
Total of all costs for the job:	$	62,903	
Cost Element 3-Reflects the 2019 Transfer to Plant	$	(62,903)	1/27/2020

Cost Element 3-reflects the 2018 Transfer to Plant	$	($114,037)	1/27/2020
Net Plant Asset Detail Total Project		($176,940)	

Audit reviewed solely the $62,903 2019 project costs associated with project 8830-1962 that was for Lebanon Mount Support 16L5 feeder project. All costs in 2019 are related to reallocation of costs associated with projects completed in prior years. Based on a review of the plant asset charge detail the project was charged to 8830-C36435 rather than 8830-1962. The project also consisted of 2018 costs of $114,037. The project was unitized and moved from the 107 CWIP account to the 106 Completed Construction Non-Classified plant in service account on January 27, 2020 for $176,940. Based on a review of Plant System data the project is 8830-C36435 rather than 8830-1962 as provided in a list of actual projects unitized to plant in service.

<u>Review of payroll, invoices, materials, and overhead support</u>

	2018	2019	Total
Contractors	$ 26,723	$ 4,999	$ 31,722
Labor	$ 38,863		$ 38,863
Materials	$ 1,520	$13,211	$ 14,731
Overheads	$ 46,931	$44,693	$ 91,624
Total	$ 114,037	$62,903	$ 176,940
Overheads	41.15%	71.05%	51.78%

<u>Materials</u>

The Company provided the journal entries of three transactions from February and March 2019 that were for utility poles, and electrical cable. The entry indicates the Company used thirteen 40-foot utility poles that were from February 24, 2019 that was for $4,387. The Company on March 29, 2019 that was for 4,454 of spacer cable that was for $4,050. The Company did not provide any actual invoices or historical inventory records such as materials tickets. **Audit Issue #5**

Overheads

The project has a 51.78% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Invoices

Audit reviewed a January 2019 invoice that was $760 and a $760 June 2019 Hunter North Associates invoices that summed to $1,520 that was for flagging/traffic control. Audit verified the hours worked and hourly rates charged on the invoices were calculated correctly.

Audit reviewed a $1,988 January 2019 JCR Construction Company invoice that was for the installation of rock bolts on poles and installation of anchors on utility poles. Audit verified the hourly rates and hours worked on the invoice were calculated correctly.

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for the $19,278. **Audit Issue #6**

Retirements

The Company provided the $5,114 Quarter 1, 2020 retirements that were done. The Company retired 390 assets in Enfield. The assets retired were noted from the following:

Account	Quantity	Amount
364	13	$2,321
365	3,172	$2,125
368.2	10	$668
Total	390	$5,114

Bids and Project Documentation

GSE indicated there is no 2019 project documentation for the Lebanon Area Low Voltage Mitigation project as it was a carryover project from prior years. All costs in 2019 are related to reallocation of costs associated with projects completed in prior years. Based on a review of the plant asset charge detail the project was charged to 8830-C36435 rather than 8830-1962.

8830-1954 Install Mt. Support 16L-16L5 Feeder Tie

Unitized in 2019 8830-1954 Mt. Support Leb. 16L2-L5 Feeder $146,451

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 45,540	
Cost Element 2-Stores and Materials	$ 21,210	
Cost Element 4-Vouchers	$ 15,107	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 64,053	
Cost Element 9-AFUDC	$ 541	
Total of all costs for the job:	$ 146,451	
Cost Element 3-Reflects the 2018-2019 Tran to Plnt	$ (146,451)	9/1/2019
Cost Element 3-reflects the 2020 Assets Transfer to Plant	$ ($13,244)	9/1/2019
Net PowerPlan Detail Total Project	($159,695)	

Audit reviewed project 8830-1954 that was to tie the Mt. Support feeder 16L2-L5 in Lebanon. The legacy WennSoft plant asset charge detail indicates the project is 8830-1854. Audit reviewed $146,451 in 2018 and 2019 project costs that were unitized on September 1, 2019 per the PowerPlan GL data to the 106-plant account and the 365 overhead conductor's account. The Company indicated in 2020 there were an additional $13,244 in 2020 plant costs. The 8830-1854 project was unitized to plant in service for $159,695. The Company in October 2022 began using the PowerPlan fixed asset system and the journal entry screenshot indicates the entire project was unitized to plant for $154,695 on September 1, 2019.

Review of payroll, invoices, materials, and overhead support

	2018	**2019**	**2020**	**Total**	**Total Overhead**
Contractors		$ 15,107	$ 873	$ 15,980	
Labor	$ 3,794	$ 41,746		$ 45,540	
Materials	$ -	$ 21,210	$ 445	$ 21,655	
Overheads	$ 6,807	$ 57,246	$11,926	$ 75,979	47.58%
AFUDC	$ 111	$ 430		$ 541	
	$10,712	$ 135,739	$13,244	**$ 159,695**	

Materials

The Company provided the journal entries for two December 6, 2019 entries that was for one load break switch that was for $3,807 and 9 50-foot wood poles that were for $4,592. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Invoices

Audit reviewed an April 2019 Asplundh Tree Expert invoice that was for $2,387. The work consisted of tree clearing/removal. Audit verified the hours worked and hourly rates charged on the invoice was calculated correctly.

Audit reviewed a June 2019 $1,568 Hunter North Associates Invoice that was for flagging/traffic control personnel. Audit verified the hours worked and hourly rates charged on the invoice were calculated correctly.

Payroll

Audit reviewed a $3,037 bi-weekly payroll report from April/May 2019 that was for labor installation on the substation of spacer cable. Audit was able to verify the hourly pay multiplied by the hours worked.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Overheads

The project has a 47.58% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Project Bids and Documentation

This project did not go out to bid as it was done using internal Company labor.

Audit reviewed the signed March 2019 Business Case that was for internal labor to install a Mt. Support 16L2-16L5 feeder tie in Lebanon. This was a discretionary project that was rationalized for Company spending as an improvement to resolve load planning criteria to reduce outages along Route 120 near Dartmouth College. The project installed 1,250 feet of 477 spacer cable along Lahaye Drive in Lebanon. The project was budgeted in 2019 at an estimated cost of $200,000 and to be completed in calendar year 2019. The Project Capital Expenditure Form was authorized for up to $200,000. The form was signed in March 2019 by the requisitioner, Senior Engineering Director with authorization authority up to $250,000, and the VP of Finance and Administration.

Audit reviewed the March 2020 project closeout documentation that was signed by the Electric Engineering Director, and VP of Engineering. The project indicates the project's budgeted costs were $200,000 and the actual costs were $135,738.72. This is $64,261 cost under run, and it is under the budgeted amount. The project per the review by Audit was unitized to plant in 2020 for $146,450 based on a review of the project detail provided by the Company. This is a $10,712 that is the result of 2018 project additions.

Cost of Removal

There were not any cost of removal charges for this project because the Company specified it was an install only.

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog was noted to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue #5**

8830-1956 Install 13L2-9L3 Feeder Tie

Unitized in 2019 8830-1956 Install 13L2-9L3 $246,037

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 2,729	
Cost Element 2-Stores and Materials	$ 30,310	
Cost Element 4-Vouchers	$ 181,496	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 29,332	
Cost Element 9-AFUDC	$ 2,170	
Total of all costs for the job:	$ 246,037	
Cost Element 3-Reflects the 2018-2019 Tran to Plnt	$ (246,037)	11/1/2019
Cost Element 3-reflects the 2020 Assets Transfer to Plant	$ $61,633	11/1/2019
Net PowerPlan Detail Total Project	($184.404)	

Audit reviewed the project 8830-1956 that was to install a 13L-9L3 feeder tie in Londonderry. The WennSoft legacy plant asset charge detail indicates the project is 8830-1856. Audit reviewed $246,037 in 2018 and 2019 charges that were assets that were unitized on November 1, 2019. In 2020 the Company had a ($61,633) credit adjustment reducing the entire project to $184,404. The PowerPlan plant asset system indicates the entire project was unitized to plant in service account 106 completed construction for $184,404 on November 1, 2019. The 365 overhead conductors were booked for the same amount.

Review of payroll, invoices, materials, and overhead support

	2018	2019	2020	Total	Overhead
Contractors	$10,123	$ 171,373	$ (78,964)	$ 102,532	
Labor	$ 1,854	$ 875		$ 2,729	
Materials	$ -	$ 30,310	$ (621)	$ 29,689	
Overheads	$ 6,101	$ 23,231	$ 17,952	$ 47,284	25.64%
AFUDC	$ 296	$ 1,874		$ 2,170	
	$18,374	$ 227,663	$ (61,633)	**$ 184,404**	

Materials

The Company provided the December 2019 journal entries for the replacement of nine wooden poles and one switch. The total transaction was for $8,399. The Company did not provide the complete historical inventory tickets or invoice receipts. **Audit Issue #5**

Invoices

Audit reviewed an October 2019 JCR Construction Company invoices that was for $72,875 for work performed on the 9L3/3L2 Feeder tie project on Roulston Road in Windham. The work consisted of construction work and construction rental equipment. Audit verified the hours worked and hourly rate was calculated correctly.

Audit reviewed two Asplundh Tree Expert invoices that were from April and May 2022 that both summed to $7,233. The work consisted of tree trimming and clearing. Audit verified the hours work and hourly rates charged were calculated correctly on the invoices.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Cost of Removal

There were not any cost of removal charges for this project because the Company specified it was an install only.

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog has to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue #5**

Project Bids and Documentation

This project did not go out to bid because it was done internally by the Company.

Audit reviewed the March 2019 Business Case that was for internal labor to install a 13L2-9L3 feeder tie in Windham. The discretionary project was a system improvement to extend 2,000 feet of three phase 1/0 AL tree wire from pole 26 on Rockingham Rd. to pole 22 on Roulston Rd in Windham. This was done for the purpose of creating a new feeder tie between the 9L3 feeder and to the Spicket River 13L2 feeder. The project was recommended to provide a backup supply for outages or issues along Sears/Rockingham Rd in Windham. The project provides a backup for an area experiencing load growth. The project was budgeted in 2019 at an estimated cost of $200,000 and to be completed in calendar year 2019. The Business Case Capital Expenditure was authorized for up to $200,000. The form was signed/approved by the requisitioner, Senior Engineering Director with authorization authority up to $250,000, and the VP of Finance and Administration.

The Company was not able to locate the Project Capital Expenditure Form. **Audit Issue # 5** Audit reviewed a signed March 2020 Change Order Request Form increasing the authorized amount from $200,000 to $227,671.64. This is a $27,671.64 increase. The Change Order Form justifies the basis for increasing the authorized the over spent amount as being driven by an accrual for $85,000 related to construction costs that were invoiced at the same time. The form indicates with a reversal of the accrual the total project costs will be below the budget. The

Change Order Request was signed by the Manager of Electrical Engineering and the Senior Director of Engineering.

Audit reviewed the signed March 2020 Project Closeout Form that indicates the project was ($27,671.64) over budgeted. The budgeted costs were $200,000 and the actual costs were $227,671.64. The cost over-run was the result of an $85,000 accrual at the end of 2019 which resulted in the project appearing to be overspent. The closeout notes the Project Manager will work with Finance to ensure the accrual has been reversed. The Closeout was signed by the Manager of Engineering and the Senior Director of Engineering. The Closeout indicates most of the charges were external rather than internal. The project was unitized to plant in service for $246,037 based on 2018 and 2019 project costs. This is a $18,365 increase compared to the project closeout. In 2020 there was a ($61,633) cost adjustment related to the accrual adjustment. This brought the total cost of the project to $184,404. The project was done externally perhaps the project should have gone out to bid. **Audit Issue #5**

<u>2020 Projects</u>

<u>8830-2024 LED Street Light Conversion</u>

<u>Unitized in 2020 8830-2024 LED Streetlight Conversion $257,404</u>

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 25,255	
Cost Element 2-Stores and Materials	$ 124,059	
Cost Element 4-Vouchers	$ 5,837	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 116,488	
Cost Element 8- CIAC	$ (27,180)	
Cost Element 9-AFUDC	$ 12,945	
Total of all costs for the job:	$ 257,404	
Cost Element 3-Reflects the 2019-2020 Tran to Plnt	$ (257,404)	8/1/2020
Cost Element 3-reflects the 2020 Assets Transfer to Plant	$ (41,816)	12/31/2021
Net PowerPlan Detail Total Project	($299,220)	

Audit reviewed the 2020 8830-2024 LED Streetlight conversion project. The WennSoft legacy plant detail indicates this was project 8830-1924. Audit reviewed $257,404 in 2019 and 2020 project costs that were unitized to plant in service on August 1, 2020. The total project included an additional $41,816 in 2021 plant additions to bring the entire project to $299,220. The PowerPlan plant system indicates the entire project was unitized to plant in service 101 and booked to the 373 Streetlights account for $299,220.

Review of payroll, invoices, materials, and overhead support

	2019	2020	2021	Total	Overhead
Contractors	$ 2,490	$ 3,347	$ 1,965	$ 7,802	
Labor	$ 23,837	$ 1,418	$ 3,957	$ 29,212	
Materials	$ 118,341	$ 5,718	$17,034	$ 141,093	
Overheads	$ 108,981	$ 7,507	$18,860	$ 135,348	45.23%
AFUDC	$ 2,161	$10,784		$ 12,945	
CIAC	$ (27,180)	$ -	$ -	$ (27,180)	
Total	$ 228,630	$28,774	$41,816	$ 299,220	

Materials

The Company provided the journal entries for 118 September-December 2020 that was for the installation of Luminaire LED 48W, 50W, and 130W Type II roadway streetlights. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Payroll

Audit reviewed a $875 bi-weekly payroll report from November 2019 that was for labor installation of municipal streetlights. Audit was able to verify the hourly pay multiplied by the hours worked.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Overheads

The project has a 45.23% overhead rate. The Company just gave a generic answer that overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

CIAC

The Company provided the signed April 2019 Town of Salem $27,180 contract for LED conversion phase 2 for the replacement of old municipal streetlights. The signed agreement included the replacement of old halogen fixtures with LED streetlights along with any underappreciated value. The Company provided the cash journal entry from May 13, 2019. The Company debited the Cash account 8830-2-0000-10-102-1310 for $27,180 and credit the CWIP account 8830-2-0000-10-1618-1070 for the same amount.

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation COR account #8830-2-0000-10-1655-1084 for $17,978 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $57,907. **Audit Issue #6**

Retirements

The Company provided the Quarter 4, 2022 list of retirements that were done for streetlights that summed to $374,843 based on the retirement of 152 streetlights that were booked to the 10101000-plant account.

Project Bids and Documentation

This LED Street Light Conversion project was done using internal resources, so the project did not go out to bid.

There was not a Business Case for this project because the LU Capital Policy does not require one for this type of project. The March 2020 signed Capital Expenditure Form authorized $400,000 based on historical budgeted amounts from prior years. The Project Capital Expenditure Form was signed/approved by the Electrical Engineering Manager up to $25,000, Senior Director of Electrical Engineering up to $250,000, Senior VP of Operations up to $500,000, and State President up to $500,000.

The Project Closeout Report was signed in March 2021 by the Manager of Electrical Engineering and VP of Electrical Engineering. The Closeout Report indicates the budgeted project costs were $200,000 while the actual project costs were $82,117.60. This is a $117,882 cost under run that was the result of CIAC charges offsetting accrual charges in 2020. The closeout indicates the remaining budget was reallocated to other 2020 capital projects. The project was closed out to plant in service for $257,404 for 2019 and 2020 project costs. This is a $175,286 difference compared to what was unitized to plant in service. **Audit Issue #5**

8830-2025 IT Systems and Equipment Blanket

Unitized in 2020 8830-2025 IT Systems and Allocations $47,398

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$	(78)	
Cost Element 2-Stores and Materials	$	0	
Cost Element 4-Vouchers	$	106,689	
Cost Element 5-Outside Services	$	0	
Cost Element 6- Burden	$	49,835	
Cost Element 3- Transfer to 106	$	109,049)	
Cost Element 9-AFUDC	$	0	
Total of all costs for the job:	$	47,398	
Cost Element 3-Reflects the 2019-2020 Tran to Plnt	$	(47,398)	12/31/2020

Audit reviewed project 8830-2027 that was a blanket project for IT systems and allocations for the year. Audit reviewed a portion of the project that summed to $47,398 that was for a Quandra System upgrade. This blanket project is for the purchase of IT assets such as computers, servers, upgrades, and other technological needs of the Company each year. The legacy WennSoft charge detail indicates the costs reviewed are part of three projects 8830-1825, 8830-1925, and 8830-2025. The GL indicates the project was unitized to plant in service account

106 Completed Construction Not Classified. The project was also booked to the 303-software account.

Review of payroll, invoices, materials, and overhead support

	2019	2020	Total	Overheads
Contractors	$ 71,974	$ 34,715	$ 106,689	
Labor		$ (78)	$ (78)	
Materials			$ -	
Overheads	$ 1,470	$ 48,365	$ 49,835	105.14%
AFUDC			$ -	
Transfer to 106	$ (27,310)	$ (81,739)	$(109,049)	
Total	$ 46,134	$ 1,263	$ 47,398	

Overheads

The project has a 105.14% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Invoices

Audit reviewed a September 2019 Softchoice invoice that was for $7,600 that was for the purchase of five Dell Latitude Laptop computers. Audit verified the charges on the invoice were calculated correctly.

Audit reviewed the December 31, 2019 $54,085 Liberty Utilities Canada Capital bill for Granite State Electrics share of the allocation that was 6.95%

Cost of Removal

There were not any cost of removal charges for this project provided by the Company. The Company indicated install only projects do not have any cost of removal charges associated with them. This project was for the installation of a Quandra Software Upgrade so there would not be a cost of removal charges.

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog has to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue # 5**

Project Bids and Documentation

This project did not go out to bid because it was done using internal Company resources. Based on a review of the cost details most of the charges are for contractors rather than labor so the Company should have considered putting the project out to bid. **Audit Issue #5**

The Blanket Project Authorization Form was for the replenishment of IT purchases, software, equipment, and infrastructure. The project was authorized to spend up to $125,000 and signed/approved in April 2020 by the IT Manager authorized up to $25,000 and Director of IT authorized up to $250,000. The April 2020 Capital Expenditure Form authorized spending of up $125,000 for IT Equipment/Infrastructure. The form was signed/approved by the IT Manager and Director of IT.

The March 2021 Project Closeout was signed by the IT Manager and IT Director. The project indicates the budgeted amount was $125,000 and the actual amount spent was $183,976. This is a ($58,796) cost over-run that was the result of a $71,624.32 Quandra Upgrade allocated to project 8830-2027. Audit reviewed $47,398 of the $71,624 Quandra upgrade costs.

<u>8830-2013 Distribution Asset Replacement</u>

<u>Unitized in 2020 8830-2013 Distribution Asset Replacement $83,378</u>

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 28,874	
Cost Element 2-Stores and Materials	$ 12,492	
Cost Element 4-Vouchers	$ 1,640	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 40,372	
Cost Element 9-AFUDC	$ 0	
Total of all costs for the job:	$ 83,378	
Cost Element 3-Reflects the 2020 Tran to Plnt	$ (83,378)	12/1/2020

Cost Element 3-reflects 2021-2022 Assets Transfer to Plant	($102,548)	12/31/2022
Net PowerPlan Detail Total Project	($185,926)	

Audit reviewed project 8830-2013 that is a blanket project for the replacement of distribution assets. Audit reviewed solely $83,378 in 2020 project costs out of $185,926 in total project costs. The additional project costs contained 2021 and 2022 plant additions. The Distribution Asset Replacements were booked to the 106 completed construction account on December 1, 2020. The entire $185,926 that was closed to PowerPlan 101 in service with the conversion to SAP in October 2022 included 2021 and 2022 costs.

<u>Review of payroll, invoices, materials, and overhead support</u>

	2020	**Overheads**
Contractors	$ 1,640	
Labor	$28,874	
Materials	$12,492	
Overheads	$40,372	48.42%
AFUDC		
Transfer to 106		
Total	$83,378	

Materials

The Company provided the October 1, 2020 journal entry one box and utility splicer cable that was for $1,649. Audit reviewed a December 2020 entry for six fifty foot wood poles for $2,680. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Invoices

Audit reviewed two December 2020 Town of Salem invoices that was for $3,000 for police services related to work on the utility construction project.

Payroll

Audit reviewed a $4,388 bi-weekly payroll report from October and December 2020 that was for labor installation of conduit and other electrical distribution station assets. Audit was able to verify the hourly pay multiplied by the hours worked.

Overheads

The project has a 48.42% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation COR account #8830-2-0000-10-1655-1084 for $7,724 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $33,809. **Audit Issue #6**

Retirements

The Company provided the $2,211 December 2020 assets that were retired in Enfield. The Company retired 73 Poles, cables, cutouts, and switches.

Account	Asset	Quantity	Amount
364	Poles	10	$401
365	Cable/Switch	63	$1,810
Total		73	$2,211

Project Bids and Documentation

This project did not go out to bid because it was done using internal Company resources.

A Business Case was not required because per LU Capital Project this was a blanket annual project. The signed/approved February 2020 Project Capital Expenditure Form indicates the mandated annual blanket project was for the replacement of line or substation assets based upon the inspection of asset condition and data. The project was authorized to spend $400,000 based on historical past spending. The CAF was signed by the Electrical Engineering Manager up to $25,000, Senior Director of Electrical Engineering up to $250,000, Senior VP of Operations up to $500,000, and the State President up to $500,000.

The Closeout was signed/approved by the Manager of Electrical Engineering and Senior Director of Engineering in March 2021. The closeout indicates the budgeted cost of the project was $400,000 while the actual cost of the project was $136,432. This is a $263,562 cost under run per the closeout report. The Company unitized $185,925 to plant in service for project 8830-2013 for the entire project. This is a $49,493 difference compared to what was unitized to plant in service. **Audit Issue #5**

2021 Projects

8830-2127 IT Systems Allocations-Corporate

Unitized in 2020 8830-2127 IT Systems and Allocations $146,637

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$	0
Cost Element 2-Stores and Materials	$	0
Cost Element 4-Vouchers	$	146,757
Cost Element 5-Outside Services	$	0
Cost Element 6- Burden	$	(120)
Cost Element 9-AFUDC	$	0
Total of all costs for the job:	$	146,637
Cost Element 3-Reflects the 2019-2021 Tran to Plnt	$	(146,637) 12/1/2021

Audit reviewed project 8830-2127 that was an IT project done at the corporate level for work related to a Customer Information System project upgrade. The project was booked to the plant in service 106 account completed construction on December 1, 2021 and was booked to the 303 Software account.

Review of payroll, invoices, materials, and overhead support

	2019	2020	2021	Total	Overheads
Contractors	$15,858	$ 4,281	$ 126,618	$ 146,757	
Labor				$ -	
Materials				$ -	
Overheads			$ (120)	$ (120)	-0.08%
AFUDC				$ -	
CIAC				$ -	
Total	$15,858	$ 4,281	$ 126,498	$ 146,637	

Invoices

Audit reviewed a $125,777 Liberty Utilities Canada Invoice that was from September 2021. The charges represent GSE IT capital allocation of 7.08% out of $890,501 in IT capital spending in 2021.

Cost of Removal

There were not any cost of removal charges for this project provided by the Company. The Company indicated install only projects do not have any cost of removal charges associated with them. This project however was a blanket for a variety of different IT project allocations such as purchasing computers, servers, and any other technological needs so the Company should have booked cost of removal charges. **Audit Issue #5**

Retirements

The Company did not retire any assets associated with this project and the Company indicated there is presently a backlog of retirements that need to be done. The backlog has to do with restrictions in the old Great Plains system and the new PowerPlan Fixed Asset System. **Audit Issue #5**

Project Bids and Documentation

The Company provided the Oakville Corporate Business Case originally from November 2017 but amended in February 2019 for the Enterprise Customer and Communications Convergence Technology Infrastructure Upgrade. The Corporate project was for the upgrade of a new Customer Service Information System. The Company was unable to locate the Capital Expenditure Form. **Audit Issue #5**

This project was executed at the corporate level and not bid by the local NH Staff. The project was for a Call Center Customer Information System software upgrade. The backup provided was an allocation summary by division that is a summary of a IVR PHONSYS Enterprise Infrastructure C3 upgrade project. GSE was allocated $260,681 or 6.23% out of $6,163,243 of the total project. The Company received four qualified bids and based on a scoring rubric Altivion/Longview was the selected winning bidder. The project document was signed in June 2021 by the Corporate IT Director to close out the project division allocation. The project in 2021 was unitized to plant in service for $146,637.

8830-2139 IE URD Cable Replacement

Unitized in 2021 8830-2139 URD Cable Replacement $235,107

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 48,967	
Cost Element 2-Stores and Materials	$ 21,784	
Cost Element 4-Vouchers	$ 75,493	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 127,054	
Cost Element 8-CIAC	$ (40,000)	
Cost Element 9-AFUDC	$ 1,809	
Total of all costs for the job:	$ 235,107	
Cost Element 3-Reflects the 2019-2021 Tran to Plnt	$ (235,107)	6/1/2021
Cost Element 3-reflects the 2021-2022 Assets Trans. Plnt	($326,647)	12/31/2022
Net PowerPlan Detail Total Project	($561,754)	

Audit reviewed project 8830-2139 that was for an Underground Residential Distribution Cable (URD) in Pelham. Audit reviewed solely $235,107 in project costs unitized in 2021 that was part of a larger $561,754 project that included legacy WennSoft projects 8830-1939, 8830-2039, and 8830-1870. The $561,754 was unitized to plant in service when GSE transitioned to SAP in October 2022 and contained additional project costs that were from 2021 and 2022. The 2021 8830-2139 project was unitized to plant in service 106 Completed Construction Non-Classified and the 367 Underground Conductors and Devices.

Review of payroll, invoices, materials, and overhead support

	2019	2020	2021	Total	Overheads
Contractors	$60,417	$ 5,936	$ 9,140	$ 75,493	
Labor	$ 9,474	$ 36,703	$ 2,790	$ 48,967	
Materials	$ 2,085	$ 19,146	$ 553	$ 21,784	
Overheads	$14,275	$ 92,054	$ 20,725	$ 127,054	54.04%
AFUDC		$ 1,809		$ 1,809	
CIAC		$ (40,000)		$ (40,000)	
Total	$86,251	$ 115,648	$ 33,208	**$ 235,107**	

Invoices

Audit reviewed a July 2021 D.R. Key Corp. $5,280 invoice that was for construction work and materials associated with the cable replacement. The charges included materials used such as dump trucks, debris removal, excavation, trailers, and wheelbarrows. Audit verified the charges on the invoice were calculated correctly.

Audit reviewed a $55,154 February 2020 Novinium invoice that was for labor associated with the installation of the new 15kV cable. Audit verified the hourly rate and hours worked were calculated correctly on the invoice.

Audit reviewed an August 2021 Parsons invoice that was for $2,739 that was for engineering, consulting, and mileage reimbursement associated with the 15kV cable installation project. Audit verified the hours worked and hourly rate charged on the invoice was calculated correctly.

CIAC

The Company provided the signed May 2020 Miscellaneous Construction agreement for $40,000 for the installation of a new electrical line and two new utility poles for an apartment building complex in West Lebanon. Audit reviewed the $40,00 cash check and the supporting cash journal entry. The journal entry debited the Cash account 8830-2-0000-10-1020-1310 for $40,000 and credited the CWIP account 8830-2-0000-10-1618-1070 for the same amount.

Overheads

The project has a 54.04% overhead rate, and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation account #8830-2-0000-10-1655-1084 for $5,350 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $1,467. **Audit Issue #6**

Retirements

The Company did not provide any retirement entries for this project but did indicate they presently have a retirements backlog that needs to be completed due to the issues of switching from the legacy systems to SAP/PowerPlan in October 2022. **Audit Issue #5**

Project Bids and Documentation

The project did not go out to bid because it was done using internal Company resources.

Audit reviewed a URD cable replacement Business Case from January 2021 that was signed/approved by the Manager of Electrical Engineering and the Senior Director of Electrical Engineering. The Business Case was authorized to spend up to $500,000. The 8830-2139 URD Cable Replacement project was a discretionary project that aims to improve aims to provide resolution to improve reliability/address pocket problems in the URD/UCD. The injection of cable rejuvenation fluids can extend the operating life of poor performing cable. The cable replacement can also reduce poor performing cable disruptions.

Audit reviewed a signed/approved January 2021 Project Capital Authorization Form that authorized up to $500,000 for the URD Cable Replacement project. The January 2021 Capital Expenditure Form was signed/approved by the Electrical Engineering Manager up to $25,000, Senior Director of Electrical Engineering up to $250,000, Senior VP of Operations up to $500,000, and State President up to $500,000.

Audit reviewed a signed/approved January 2022 Project Closeout report that indicated the project was budgeted for $500,000 but only actually spent $36,295. This is a $463,705 under budgeted amount because the project scope was reduced to engineering only and excluded construction. The project was unitized to plant in service for $235,107. This is a $198,812 difference compared to the Project Closeout. **Audit Issue #5**

8830-2119 IE-NN Transformer Upgrades

Unitized in 2021 8830-2119 Transformer Upgrade $38,828

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$	12,146
Cost Element 2-Stores and Materials	$	3,225
Cost Element 4-Vouchers	$	868
Cost Element 5-Outside Services	$	0
Cost Element 6- Burden	$	22,544
Cost Element 9-AFUDC	$	44
Total of all costs for the job:	$	38,827
Cost Element 3-Reflects the 2020-2021 Tran to Plnt	$ (38,827) 12/1/2021	

Cost Element 3-reflects the 2021-2022 Assets Trans. Plnt	($32,200)	12/31/2022
Net PowerPlan Detail Total Project	($71,027)	

Audit reviewed project 8830-2119 that was for a transformer upgrade in Salem that was part of a larger $71,027 project. Audit solely reviewed $38,827 of the project costs that were unitized to plant in 2021. The project also contained the legacy WennSoft projects 8830-2019 and 8830-1919. The project costs Audit reviewed was unitized to plant in service 106 Completed Construction Non-Classified on December 1, 2021 for $38,827. The entire project was unitized to plant in service 101 account for $71,027 in December 2022 that contained additional 2021 and 2022 project costs since the Company transition to SAP in October 2022.

Review of payroll, invoices, materials, and overhead support

	2020	2021	Total	Overheads
Contractors		$ 868	$ 868	
Labor	$ 1,578	$10,568	$12,146	
Materials	$ 1,708	$ 1,517	$ 3,225	
Overheads	$ 2,890	$19,654	$22,544	58.06%
AFUDC	$ 44		$ 44	
CIAC			$ -	
Total	$ 6,220	$32,607	**$38,827**	

Materials

The Company provided the journal entry for an August 14,2021 for two cross arms that were for $513. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue # 5**

Invoices

Audit reviewed an August 2021 $488 Town of Salem invoice that was for police services associated with a construction site for the transformer upgrade project. Audit verified the hours worked and hourly rate on the invoice were calculated correctly.

Overheads

The project has a 58.06% overhead rate and the Company just gave a generic answer of overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Project Bids and Documentation

This project did not go out to bid because it was done using internal Company resources.

There is no Business Case for this project because it was not required by the LU Capital Policy as it is a planned replenishment project. The project was authorized to spend $76,500. The distribution transformer upgrade program is a proactive load-based replacement program beyond what is already being performed during customer service upgrades and system improvement projects. The Capital Expenditure Form was signed in January 2021 by the Manager of Electrical Engineering up to $25,000 and the Senior Director of Electrical Engineering up to $250,000.

Audit reviewed the signed/approved February 2022 Project Closeout Report that indicated the project cost $33,293 and the budgeted amount indicates the project was for $50,000. The project was $16,707 under budget per the closeout report. The closeout report was signed/approved by the Project Supervisor, Electrical Engineering Manager, and the Senior Director of Electric Operations. Based on a review of the plant detail by audit the actual cost was $38,828. This is a $5,535 difference compared to the Project Closeout. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation account #8830-2-0000-10-1655-1084 for $4,274.

Retirements

The Company did not provide any retirement entries for this project but did indicate they presently have a retirements backlog that needs to be completed due to the issues of switching from the legacy systems to SAP/PowerPlan in October 2022. **Audit Issue #5**

2022 Projects

8830-2083 Ten Year Inventory System Improvements

Unitized in 2022 8830-2083 10 Year Inventory System Improvements $110,735

Audit was provided with the Plant asset system summary of expenses:

Cost Element 4-Vouchers	$ 85,331	
Cost Element 6- Burden	$ 25,404	
Cost Element 9-AFUDC	$ 0	
Total of all costs for the job:	$ 110,735	
Cost Element 3-Reflects the 2020-2022 Tran to Plnt	$ (110,735)	8/1/2021

Audit reviewed project 8830-2083 that was for an inventory management solution as the prior Great Plains System was reported by Liberty to be a cumbersome manual process with many delays, data entry, and batch processing. The PowerPlan screenshot provided to Audit indicates the project was closed to the 106 Completed Construction on August 1, 2021, and booked to the 303-software account for $110,735 in August 2022. The inventory management solution system remains in place, and in conjunction with the SAP software change. The charges were booked over a multi-year period.

Review of payroll, invoices, materials, and overhead support

	2020	2021	2022	Total	Overheads
Contractors	$ 30,804	$54,527		$ 85,331	
Labor				$ -	
Materials				$ -	
Overheads	$ 10,090	$15,314		$ 25,404	22.94%
AFUDC				$ -	
Unitized				$ -	
Total	$ 40,894	$69,841	$ -	**$ 110,735**	

Invoices

Audit reviewed three Data System International (DSI) invoices from April and June 2020 that summed to $25,268 that was for the purchase of a 4.3" Zebra 53 STD Key Alphanumeric handheld data entry device to help with data optimization for materials data entry in the field. The other charges on the invoice were the Cloud internet charges and associated licenses. Other charges consisted of device battery packs, power supply and power cords. Audit verified the charges on the invoices were calculated correctly.

Audit reviewed a $54,527 Liberty Utilities Canada Invoice that was from August2021. The charges represent GSE IT capital allocation of 7.08% out of $890,501 in IT capital spending in 2021.

Project Bids and Documentation

The Company did not provide any backup if the project went out to bid other than specifying that the Company picked a contractor that met the needs of the Company. The Business Case indicates the Company selected DSI Cloud Group. This project should have gone out to bid to see if it was possible to get a better quote. **Audit Issue #5**

Audit reviewed a signed/approved 2020 Business Case for Project 8830-2083 that was for an inventory management solution as the prior Great Plains System was a cumbersome manual process with many delays, data entry, and batch processing. The delays cause inaccurate on hand balances in addition to inaccurate values posting to jobs. The Company selected DSI Cloud Inventory as the vendor for a cloud-based licensing solution that will also last with the implementation of SAP. The DSI Cloud product offers purchase order receipts, inventory put away, transfers, and cycle counting, shipping, pick, sales order slips, and numerous other advances. The Business Case indicates a 59-month license agreement that began on September 1, 2019 to July 31, 2024 for $111,805. The project was to take 1-3 years to complete. The total project was estimated to cost $136,110. The Business Case was signed/approved in January 2020 by the Project Manager up to $25,000, the Senior Director of Operations up to $250,000 and the VP of Operations up to $500,000.

Audit reviewed the January 2020 Project Capital Expenditure Form that was signed/approved by the Project Manager up to $25,000, the Senior Director of Operations up to $250,000 and the VP of Operations up to $500,000. The Company indicated they could not locate a project closeout form. The project was unitized to plant in service for $110,736. This is a $25,734 difference compared to the Project Capital Expenditure Form. **Audit Issue #5**

Retirements and Cost of Removal

There were no retirements or costs of removal for this IT project as it was a brand-new upgrade to make the inventory management function in Great Plains more useful so manual adjustments were not required.

8830-2241 Feeder Getaway Cable Replacement

Unitized in 2022 8830-2241 Feeder Getaway Cable $119,779

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 11,497
Cost Element 2-Stores and Materials	$ 2,495
Cost Element 4-Vouchers	$ 70,144
Cost Element 5-Outside Services	$ 0
Cost Element 6- Burden	$ 33,092
Cost Element 9-AFUDC	$ 1,853
Cost Element Other Direct Costs	$ 698
Total of all costs for the job:	$ 119,779
Cost Element 3-Reflects the 2020-2021 Tran to Plnt	$ (119,779) 12/1/2022

Audit reviewed the $119,779 Feeder Getaway Cable replacement installation on Spicket River Substation in Salem that was unitized to plant in service account 106 Completed Construction Non-Classified in PowerPlan on December 1, 2022.

Review of payroll, invoices, materials, and overhead support

	2022	Overheads
Contractors	$ 70,144	
Labor	$ 11,497	
Materials	$ 2,495	
Overheads	$ 33,092	27.63%
AFUDC	$ 1,853	
ODC	$ 698	
Total	**$ 119,081**	

Materials

The Company provided the journal entries from September 14, 2022 that was for six cable insulators, four splicer cable kits, and three arrestors. The transactions amounts for the thirteen items summed to $2,466. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Payroll

Audit reviewed a $43,302 bi-weekly payroll report from December 2022 that was for labor installation of the getaway cables and also any troubleshooting. Audit was able to verify the hourly pay multiplied by the hours worked.

AFUDC

The Company indicated they provided an embedded file of the AFUDC backup but there was not any detail other than the Audit Sample entry. **Audit Issue #5**

Bids and Documentation

The Company indicated they received four bids and selected the lowest priced bidder for the project.

Audit reviewed a $250,000 December 2021 Business Case that was signed/approved by the Project Lead up to $25,000, the Senior Electrical Engineering Manager up to $50,000, and the Senior Director of Electric Operations up to $250,000. The Business Case was for a Feeder Getaway Cable Replacement that was a discretionary project for the Spicket River Substation in Salem. The spending rationale for the project was this project vehicle provides faster feeder getaway cable replacements to improve and resolve reliability problems. The replacement of 300 feet of XLPE AL cables for the Spicket River 13L2 feeder getaway cable with new 1,000 Cu cables in a new underground conduit system.

Audit reviewed the December 2021 Project Capital Expenditure Form that authorized up to $250,000. The Capital Project Expenditure Form was signed/approved by the Project Lead up to $25,000, the Senior Electrical Engineering Manager up to $50,000, and the Senior Director of Electric Operations up to $250,000.

Audit reviewed an April 2023 project closeout for the 8830-2241 Feeder Getaway Replacement Project that indicates the project was budgeted for $250,000 while the project cost $122,213. This is $137,787 under budget but the close out does not give a reason for why the project is so under budget. The closeout report was signed/approved by the project leader and the Manager of Engineering Projects. The project was unitized to plant in service for $119,779 based on a review of the project by Audit. This is $2,234 difference compared to the Project Closeout actual amount spent. **Audit Issue #5**

Cost of Removal and Retirements

The Company did not provide any cost of removal or retirement entries for the getaway cable replacement projects. The Company indicated there is presently retirements backlog due to the SAP/PowerPlan system conversion in October 2022. **Audit Issue #5**

8830-2210 GSE Distributed Street Light

Unitized in 2022 8830-2210 Distributed Street Light $133,309

Audit was provided with the Plant asset system summary of expenses:

Cost Element 1-Payroll	$ 11,219	
Cost Element 2-Stores and Materials	$ 39,527	
Cost Element 4-Vouchers	$ 29,242	
Cost Element 5-Outside Services	$ 0	
Cost Element 6- Burden	$ 52,576	
Cost Element 8-CIAC	$ (400)	
Cost Element Other Direct Costs	$ 1,145	
Total of all costs for the job:	$ 133,309	
Cost Element 3-Reflects the 2022 Tran to Plnt	$ (106,555)	09/30/2022
PowerPlan Costs Unitized to Plant	$ (26,754)	12/31/2022
Total Unitized to Plant	$ (133,309)	

Audit reviewed the blanket project 8830-2210 that was for the replacement of municipal streetlights. The Company began using SAP in October 2022 so as a result there were two separate journal entries for projects using the legacy WennSoft Fixed Asset System and Great Plains prior to September 30, 2022. The first entry summed to $106,555 and reflects all project costs prior to September 30, 2023. The PowerPlan entries done after summed to $26,754. The entire project with both entries summed to $133,309. The Company unitized the project to the 106 Completed Construction account and the 373 Streetlighting and Signal Systems account for $133,309.

Review of payroll, invoices, materials, and overhead support

	2020	2021	2022	Total	Overheads
Contractors	$ 3,725	$10,928	$ 14,589	$ 29,242	
Labor	$ 2,048	$ 1,839	$ 7,332	$ 11,219	
Materials		$ 6,447	$ 33,080	$ 39,527	
Overheads	$ 1,797	$ 9,552	$ 41,227	$ 52,576	39.44%
ODC			$ 1,145	$ 1,145	
CIAC			$ (400)	$ (400)	
Total	$ 7,570	$28,766	$ 96,973	**$ 133,309**	

Materials

The Company provided the August 2022 journal entry for the replacement of seven Luminaire 130W LED Street Lights. The Company did not provide any invoices or historical inventory ticket records for the actual details. **Audit Issue #5**

Invoices

Audit reviewed two Granite State Cable Splicing and Testing LLC invoices. The first invoice from April 2021 was for $3,725 that was for the installation of a new foundation to new light poles, connection of the new PVC conduit, installation of mounting studs, and excavation. The June 2022 invoice was for $7,040 was for troubleshooting an outage and removing the cable feeder from the burned areas and install the new light connector. Audit verified the charges on the invoice were calculated correctly.

Audit reviewed an April 2022 $2,391 Utility Service and Assistance, Inc. invoice that was for labor and construction equipment associated with the installation of streetlights/associated fixtures. Audit verified the hourly rates and hours worked were calculated correctly on the invoice.

Overheads

The project has a 39.44% overhead rate, and the Company provided a generic answer that overheads include the internal capital overhead applied to capitalized labor, the capitalized percentages are applied to indirect department labor, overhead, fleet fuel, and maintenance costs and can result in overheads greater than 30%. The overhead rate seems high for the project. **Audit Issue #5**

Retirements

The Company did not provide any retirement entries for this project but did indicate they presently have a retirements backlog that needs to be completed due to the issues of switching from the legacy systems to SAP/PowerPlan in October 2022. **Audit Issue #5**

Cost of Removal

The Company provided the Cost of Removal entries for the work orders tested in this audit report. The Company charged the Accumulated Depreciation COR account #8830-2-0000-10-1655-1084 for $13,874 and charged Accrued Cost of Removal #8830-2-0000-20-2124-2420 for $242. **Audit Issue #6**

Project Bids and Documentation

This project did not go out to bid because the Company used internal resources to complete the project.

There is no Business Case for this project as one is not required per the LU Capital Policy as this is a mandated blanket project. The blanket project was to provide funding for new/replacement of existing municipal lighting facilities which includes LED Conversion, install streetlight poles, replacement of streetlight bulbs, and replacement of flood lights. The Capital Project Expenditure Form authorized spending of up to $125,000. The Capital Project Expenditure Form was signed/approved by the Project Manager up to $25,000, Sr. Manager of Electrical Engineering up to $50,000, and the Sr. Director of Operations up to $250,000.

Audit reviewed the March 2023 project closeout that indicated the budgeted project cost was $125,000 while the actual project cost was $81,617. This is $43,383 under budget but the closeout report does not give a specific reason for why the project was under budgeted. The closeout was signed/approved in May 2023 by the Project Manager, the Manager of Engineering Projects, and the Sr. Director of Electric Operations. The plant in service per Audit review is $133,309. This is a $51,695 difference compared to the closeout. **Audit Issue #5**

<u>Cost of Removal</u>

The Company provided the Cost of Removal (COR) entries for the work orders tested earlier in this audit report. See the *<u>Additions</u>* section for review of specific COR entries. The Company debits the Accumulated Depreciation account #15030010108000 for cost of removal charges. Prior to 2020, the Company debited 8830-2-0000-20-2124-2420, Accrued Cost of Removal. Refer to **Audit Issue #6**.

The 2022 CPR records indicated the Cost of Removal charges are ($1,472,496) while the 2022 FERC Form 1 page 219 indicates ($1,563,731). This is a $91,235 difference. **Audit Issue #2**

<u>DE 19-064 Step Adjustment Audit Reports</u>

There were three Step Adjustment Audit reports issued since the DE 19-064 GSE rate case.

- The first step adjustment Audit Report was issued on June 30, 2020. There was one Audit issue identified in the report that indicated project 8830-1912 was <u>overstated by $23,501</u> as the filing total was $1,184,186 and the GL total was $1,160,685.
- The second step adjustment Final Audit Report was issued on September 16, 2021 that identified four Audit issues related to charges that should have been booked to the 183 Preliminary Survey and Investigative Charges, Contribution in Aide of Construction (CIAC) charges that should have been removed from the final project cost, cost of removal costs that were included in the step adjustment, and pivot tables that were provided should have been more accurate. The recommended total adjustment was $647,848.
- The third and final step adjustment Audit report was issued on October 25, 2022 and there were two issues, one related to recommended project costs be removed from the filing and the second issue was related to a transformer that should not have been included because it was considered a growth project. Total recommended adjustment $1,076,831

<u>Retirements</u>

Audit verified the ($4,947,013) 2019-2022 retirements on page 219 of the FERC Form 1 in plant assets based on 2019-2022 $104,651,467 additions done over the same period. Audit verified the retirements to the CPR records. The Company in October 2022 unitized the SAP Enterprise Resource Planning System that allocated to GSE $13,541,670. The Company indicated they retired $6,613,191 in Legacy ERP software in February 2023. The Company indicated that the remaining $34,445 of the $6,613,191 had not been fully amortized. Audit reviewed the journal entry and calculations that were provided by GSE that included the retirements booked to the 101 account. The legacy software consisted of Cogsdale Billing System, Great Plains, WennSoft plant software, outage map enhancements, Cogsdale enhancements, and other legacy software enhancements.

<u>Retirement Process</u>

Retirements are processed in the PowerPlan system. The Company summarized how plant assets are retired within PowerPlan:

"*In PowerPlan, a retirement can be processed directly from the CPR (Continuing Property Records) by selecting the asset one would like to retire, associating it with a work order,* *and selecting the retirement button. This will create an entry to retire the asset from Plant in Service by crediting (101) and debiting accumulated depreciation (108). An asset can also be retired within the work order itself by creating a retirement line within the work orders as built. An as built contains a list of all items installed and removed. This results in the same entry of a credit to Plant in Service (101) and a debit to accumulated depreciation (108).*

Information is submitted by the owner of the project to the Plant Accounting department. The projects are placed in service as they are completed and the as built information outlining assets installed and removed is provided once a reconciliation of the project is complete. Retirement entries can be done in the same project in PowerPlan except for the converted 106 projects. Retirements for these projects are being done in a conversion work order as no new work order was created in PowerPlan for these."

Audit was provided the 2022 retirements that showed the retirements on the GL. The Company, in the retirement's PowerPlan PDF, books the retirement entries correctly by debiting account #108 Accumulated Depreciation and crediting the plant asset account. The Company retired ($1,116,506) in plant assets for 2022.

Accumulated Depreciation and Amortization #108, #110, #111, #115 $(123,090,712)

Audit verified the reported information seen on the FERC Form 1 to the following general ledger accounts:

15030010108000 Accrued Cost of Removal	$(8,010,584)
15501010108000 Acc Dep-Plnt in Serv	$(102,547,907)
15520010108000 Acc Dep-FC-Leg	$(1,413)
15551010108000 RWIP – Reclass	$0
15501010108100 Acc Dep-Plnt in Serv	$(188,068)
15550010108100 RWIP	$121,571
26150010108110 Long Term Cost of Removal	$(258,610)
15501010111000 Accumulated Depreciation-Plant in Service	$(12,205,701)
Total	$(123,090,712)

The account activity consisted of the monthly depreciation expenses and monthly reclassifications of expenses.

The filing schedules RR-4.1 line 2 and RR-4, line 2 reflect Accumulated Depreciation and Amortization to be ($123,210,870) while the FERC Form 1 has a 2022 ending balance of $(123,090,712). This is a ($120,158) variance that is the result of the filing schedule not including the ($1,413) booked to account 15520010108000 Acc Dep-FC-Leg and $121,571 booked to the Retirement Work In Process account 1555001010810. These were not included on the filing schedule reportedly due to a coding issue. The CPR records indicated the December 31, 2022 Accumulated Depreciation summed to $123,180,534 while the Accumulated Depreciation per the GL summed to $123,090,712. This is an $89,822 difference. **Audit Issue #2**

Depreciation and Amortization Expense

Depreciation Expense, Amortization of Intangibles, and Amortization of Regulatory Debits were combined within the filing on schedule RR-2.12 line 12 for a total of $10,720,302.

55051010403000 Depreciation Expense	$10,403,054	
55056010403000 Capitalized Depreciation- Equipment	($52,491)	
55057010403000 Capitalized Depreciation-Fleet	$79,367	
Total 403 Depreciation Expense 2022	$10,429,931	FERC F1 pg. 114 line 6
55051010404000 Amortization of Property Plant and Equip.	$435,976	
55001010405000 Amortization of Intangible Software	$93,402	
Total 404 and 405 accounts for 2022	$529,378	FERC F1 pg. 114 line 8
55021010407300 Amortization of Rate Base Offset	$144,128	FERC F1 pg. 114 ln 12
Total 403-407 Dep. And Amort. Expense accounts	$11,103,407	
40033010407300 Other Electric Revenue	($383,135)	**Audit Issue #1**
Total	$10,720,302	

Audit reviewed and tested individual plant in service depreciation transactions in the CPR to the most recent approved deprecation Study in DE 19-064. Audit was able to verify the 2022 Depreciation Expense totals on the CPR records to the GL and filing schedules that summed to $10,403,054. The CPR records indicated the December 31, 2022 Accumulated Depreciation summed to $123,180,534 while the Accumulated Depreciation while the GL summed to $123,090,712 and Filing Schedule RR-4.1 line 2 and RR-4, line 2 reflected 123,210,870.

The net $26,876 capitalized fleet/equipment overhead represents the capitalized monthly fleet, allocated on a pro-rata basis. **Audit Issue #3**

Both the $10,429,931 depreciation expense and the $529,378 Amortization of Intangible Software are offset to the Accumulated Provision for Depreciation of Electric Utility Plant account 155010108000. The Regulatory Debit Amortization was offset to the 10182300 Other Regulatory Asset Deferred Rate Case account. Audit verified the $529,378 in 2022 amortization of intangible software to the GL that were authorized for recovery as part of Commission Order 26,376 that approved the DE 19-084 GSE 2018 rate case settlement agreement. Audit reviewed and verified the $435,975 monthly deprecation calculations provided by the Company. Audit review and verified the $93,405 intangible plant software calculations that were provided by the Company. The 26,376 Order indicates the original 405 reserve balance was $1,950,390 to be amortized over a 6 year period or $325,065 per year.

The full $144,128 Amortization of Regulatory Debits is included on Filing Schedule RR-2.12. These are the amortized rate base associated with the 2018 rate case expenses that were approved for recovery in Commission Order 26,376 on June 30, 2020 that approved the DE 19-064 Settlement Agreement. The Company during 2022 amortized $24,021 monthly or $144,128 from January-June 2022. The monthly 407 entries were offset to the LTRA Rate Base Offset account 17120010182300 and the 17120010186000.

The ($383,135) Other Electric Revenue were miscoded to the GL account 10407300 related to revenue balances, that included certain charges billed to customers through the CIS system. There were also some manual adjustments for unbilled revenue as of December 31, 2022. Please see the *Revenue section* for more detailed information on this account. The amount was proformed out of the RR-2.12, but not into the revenue schedule. **Audit Issue #1**

Construction Work in Progress (CWIP) #107 $15,266,206

The filing revenue requirement schedules did not include the CWIP account. The FERC Form 1 balance for CWIP is $15,266,206 while the 15010010107000 SAP GL account summed to $15,258,393. This is a $7,813 difference the Company indicated was the result of adjustments that were identified during the preparation of the 2022 FERC Form 1. GSE indicated certain transactions were mis-mapped at conversion from Great Plains to SAP **Audit Issue #1**

Total 107 account balance per 2022 SAP GL		$15,258,393
Total 107 account balance per FERC Form 1		$15,266,206
	Variance	$ (7,813)

GL Account	Amount	Notes
50211010921000	$14,040	Exclude from 921 Office Supplies Expense add to 107
50500010107000	($5,264)	Add to 920 Other Operating Expenses-Exclude from 107
70200010107000	($962)	Add to 920 acct-Exclude from the 107 account
Total	$7,813	Total Adjustments/variance **Audit Issue #1**

Allowance for Funds Used During Construction (AFUDC)

Audit verified the AFUDC to:

47040010419100 AFUDC Equity	$(130,600)	FERC pg. 117 line 38
56201010432000 AFUDC Borrowed	$(79,309)	FERC pg. 117 line 69

Activity within both accounts was offset to the Construction Work in Process account 15010010107000. See review of individual work order in the Plant selections above for review of individual AFUDC detail.

Materials and Supplies #154 $3,759,408

The total per the filing schedule RR-4 line 6 and RR-4.2 agrees with the three SAP general ledger regulatory account 1540 and the FERC Form 1 page 110 line 48.

Account #	Amount
12100010154000	$4,259,944.41
12100510154000	($501,826.54)
12101510154000	$1,290.56
Total	$3,759,408.43

The reported FERC Form 1 balance since the prior rate case (test year ended 12/2022) reflects:

2019	2020	2021	2022
$2,950,132	$2,538,074	$2,400,315	$3,759,408

The Company, in the response to DOE Staff Data Request 4-8, provided 2020-2022 Historical Stock Status Detailed Inventory Reports. The attachments DOE 4-8-1 and 4-8-2 indicate the December 2022 Historical Stock balance is $4,259,944 while the GL accounts summed to $3,759,408. This is a ($500,536). **Audit Issue #7**

Additional material details are discussed in the review of individual projects in the *plant* section of this report.

Audit verified that the Great Plains 9/30/2022 ending balance of account 8830-2-0000-10-1380-1540, $4,034,239.53 was rolled into the SAP account 12100010154000.

Stores Expense #163 $0

The Stores Expense Undistributed account on the 2022 FERC Form 1 balance sheet, line 54 is zero. Audit reviewed the 1630 SAP general ledger account, which is the sum of six accounts totaling $54,509. As previously noted, the Company stated that the Stores Expense accounts were mapped incorrectly to account 163, and are included within expense account 920, Administrative and General Salaries on the FERC Form 1. **Audit Issue #1**

GL	G/L Account2	Regulatory Acc	GL - REG		Dec-22
121070	Stores Exp Undstrb	1630	12107010163000	$	-
500000	Salaries and Wages	1630	50000010163000	$	2,388
500300	Outside Svs	1630	50030010163000	$	33
500500	Equip & Machin Rents	1630	50050010163000	$	12,039
505000	Other Operating Exp	1630	50500010163000	$	4,383
800000	Lbr Alloc	1630	80000010163000	$	35,666
				$	54,509

Prior DE 19-064 Audit Report

Within the prior audit report, Audit Issue #4 identified $5,265 in artwork that was included in Plant in Service, in account #398, Miscellaneous Equipment. Audit had recommended that the amount be excluded from Plant in Service since it is not necessary for the safe and reliable provision of electrical service. The Company disagreed. Audit reviewed the continuing property records, and noted that the asset remains within the account #398. A**udit Issue #27**

CURRENT and Other ASSETS

Cash - $43,270,870

Audit noted the year-end general ledger cash totals on the FERC Form 1, page 110-111, lines 35 and 36 respectively:

Cash account 131	$43,238,110
Special Deposits account 134	$ 32,759
	$43,270,870 rounded

Audit verified the September ending balance to the following GP accounts:

8830-2-0000-10-1020-1310 Cash-JP Morgan	$(289,661.64)
8830-2-0000-10-1060-1340 Other Special Deposits	$ 32,455.93
Cash per the GP General Ledger 9/30/22	$(257,205.71)

Audit then verified that the September balances were rolled into the SAP general ledger system. Schedule 1604.01(a)(1)(a)BS, Bates page I-006 reflects a total December 2022 cash figure of $43,238,109.80. The following SAP accounts mapped to Cash 1310 sum to $43,238,110.63 which is $0.83 higher than the filing. As noted, that is a mismatch of account 52001010131000, Elec Pur Power Misc. Also included in the total for both the filing and the FERC Form 1 is account 24080010131000, CRL Fuel&Commod Cost $(7,031.50) and account 52001010131000 $0.83 which is also a result of the mapping issue when Great Plains merged into SAP. **Audit Issue #1**

Company Code	GL	G/L Account2	Regulatory	GL-Reg	Sep Balance	Oct Balance	Nov Balance	Dec Balance
3071	100110	Bank 1-CIB Main	1310	10011010131000	$ (289,661.64)	$ -	$ -	$ -
3071	100114	Bank 1- Clrg-MAR	1310	10011410131000	$ -	$ (10,931.00)	$ (79,139.59)	$ (6,028.49)
3071	100115	Bank 1- Clrg-CIS	1310	10011510131000	$ -	$ (3,054.60)	$ (3,054.60)	$ (3,054.60)
3071	100117	Bank 1- Clrg-Sweep	1310	10011710131000	$ -	$ -	$ -	$ 816,314.55
3071	100118	Bank 1- Clrg-ICO/FT	1310	10011810131000	$ -	$ (902,969.92)	$ (203,318,602.22)	$ 42,440,286.50
3071	100119	Bank 1-Clrg-Other	1310	10011910131000	$ -	$ (289,661.64)	$ 402.77	$ (2,376.66)
3071	240800	CRL Fuel&Commod Cost	1310	24080010131000	$ -	$ (7,031.50)	$ (7,031.50)	$ (7,031.50)
3071	520010	Elec Pur Power Misc	1310	52001010131000	$ -	$ 0.83	$ 0.83	$ 0.83
					$ (289,661.64)	$ (1,213,647.83)	$ (203,407,424.31)	**$ 43,238,110.63**
3071	188010	Restricted Cash	1340	18801010134000	$ 32,455.93	$ 32,541.36	$ 32,637.41	**$ 32,759.31**
								$ 43,270,869.94

The BlackRock mutual fund is noted in the Other Special Deposits account above.

Audit attempted to verify the general ledger amounts to a cash reconciliation, however the reconciliations provided by Company did not reconcile with a noted ($210,283,306.62) discrepancy between the reconciliation listing of general ledger account balances and the actual 12/31/2022 general ledger. Regarding the large discrepancy, the Company stated: "*An additional entry was posted after the reconciliation was completed as part of our parking lot entry process. G/L account 100118 is used for intercompany cash transfers and accruals*". The discrepancies are noted below. **Audit Issue #8**

GL	G/L Account2	GL - REG	GL Balance 12/31/22	Cash Reconciliation	Difference
100110	Bank 1-CIB-Main	10011010131000	$ -	$ -	
100114	Bank 1-Clrg-MAR	10011410131000	**$ (6,028.49)**	$ (6,028.49)	$ -
100115	Bank 1-Clrg-CIS	10011510131000	**$ (3,054.60)**	$ (3,054.60)	$ -
100117	Bank 1-Clrg-Sweep	10011710131000	**$ 816,314.55**	$ 816,314.55	$ -
100118	Bank 1-Clrg-ICO/FT	10011810131000	**$ 42,440,286.50**	$ (167,843,019.29)	$ 210,283,305.79
100119	Bank 1-Clrg-Other	10011910131000	**$ (2,376.66)**	$ (2,376.66)	$ -
240800	CRL Fuel&Commod Cost	24080010131000	**$ (7,031.50)**	$ (7,031.50)	$ -
520010	Elec Pur Power Misc	52001010131000	**$ 0.83**	$ -	$ 0.83
			$ 43,238,110.63	$ (167,045,195.99)	$ 210,283,306.62

Audit reviewed the bank statement associated with the accounts below and notes that the difference between the bank statement and reconciliation is identified as "known":

December 2022 Cash Reconciliation						
Balance per General Ledger	$	(167,038,164.49)				
Balance per JP Morgan Chase Bank Statement	$	-				
variance	$	(167,038,164.49)				
				Actual		
Explanation of Known variance:				SAP 12/31/2022		SAP vs. Recon
1. GL 100111: ACH Clearing	$	-	$	-	$	-
2. GL 100112: Check Clearing	$	-	$	-	$	-
3. GL 100113: Wire Clearing	$	-	$	-	$	-
4. GL 100114: Misc AR Clearing	$	(6,028.49)	$	(6,028.49)	$	-
5. GL 100115: CIS Clearing	$	(3,054.60)	$	(3,054.60)	$	-
6. GL 100116: CIS Other Clearing	$	-	$	-	$	-
7. GL 100117: Sweep Clearing	$	816,314.55	$	816,314.55	$	-
8. GL 100118: Inter-Co Clearing	***$***	***(167,843,019.29)***	***$***	***42,440,286.50***	***$***	***210,283,305.79***
9. GL 100119: Other Clearing	$	(2,376.66)	$	(2,376.66)	$	-
Known variance	$	(167,038,164.49)	$	43,245,141.30	$	210,283,305.79
Unreconciled variance	$	-				

Audit was also provided the bank statement related to account 24080010131000, CRL Fuel&Commod Cost $(7,031.50) which is part of a larger liability account and found no variances between the reconciliation and the bank statement.

A notation on the reconciliation indicates that the 1310 general ledger account is used primarily to record receivables from customers for Granite State Electric.

Per the Company, the BlackRock account complies with the ISO-NE financial assurance requirement in the Open Access Transmission Tariff. Audit reviewed the statement and reconciliation without exception. Both accurately reflect the general ledger balance noted above.

Interest earned on the BlackRock account is reinvested, and the debits were noted in the 1340 account and the credits posted to 8830-2-0000-40-4420-4190, Interest Income. The SAP account shows the debits to the 134 account (account #3071-10167-188010-10134000) and credits posted to 3071-10167-1016795000-470300-10419000 The reinvested income was noted on the December 31, 2022 BlackRock statement. The total for the year is $32,759.31.

Audit reviewed the current irrevocable standby letter of credit, in the amount of $7,000,000, which expires on 11/30/2023. The letter was issued by Canadian Imperial Bank of Commerce on behalf of Algonquin Power & Utilities Corp. on behalf of Liberty Utilities (Granite State Electric) Corp. in favor of ISO New England, Inc. The standby letter of credit is a contingent liability, thus not reflected on the general ledger of GSE.

The reported FERC Form 1 Cash and Other Special Deposit balances since the prior rate case reflect:

	2019	2020	2021	2022
Cash	$ 19,277.00	$ 61,625.00	$ (2,074.00)	$ 43,238,110.00
Black Rock	$ 26,962.00	$ 227,162.00	$ 5,227,213.00	$ 32,759.00

Accounts Receivable #142 $29,736,311.52

The FERC Form 1 and filing schedule 1604.01, Bates page I-006 reflect the above receivable figure. Audit verified the total to the following general ledger accounts, demonstrating the September 2022 ending balance of the Great Plains system, then the month end totals for October, November, and December 2022 per the SAP system:

G/L Account2	Regulatory	GL - REG	SEP Balance	OCT Balance	NOV Balance	DEC Balance
Customer AR-CIS-Ctrl	1420	11001010142000	$ 15,258,152.10	$ 14,950,774.81	$ 16,044,560.09	$ 19,227,997.79
Cst AR-Mnl	1420	11001210142000	$ (35,563.58)	$ 737,519.85	$ 678,919.48	$ 939,928.12
Cst AR-Mktr-NONPOR	1420	11001810142000	$ 1,123,066.39	$ 1,018,451.91	$ 1,334,651.71	$ 1,435,730.60
Cst AR (NonCIS)-Ctrl	1420	11002010142000	$ 1,725,743.42	$ 1,774,718.37	$ 1,728,632.97	$ 1,701,770.06
Cst AR (NonCIS)-Mnl	1420	11002110142000	$ -	$ -	$ -	$ (45,013.51)
AR-Legacy	1420	11003010142000	$ 3,297,343.22	$ 2,554,212.13	$ 2,511,255.15	$ (419,065.52)
CRA Fuel&Commod Cost	1420	13080010142000	$ 5,803,468.97	$ 2,627,374.31	$ 2,627,374.31	$ (1,048,436.69)
CRA Fuel&Commod Cost	1420	13080010142001	$ -	$ (3,093,089.25)	$ (423,018.59)	$ 7,943,400.67
CRA R8 Adj Mech	1420	13110010142000	$ -	$ -	$ -	$ -
			$ 27,172,210.52	$ 20,569,962.13	$ 24,502,375.12	**$ 29,736,311.52**
			Great Plains	SAP	SAP	SAP

Audit verified the September ending balance to the GP accounts:

8830-2-0000-10-1101-1420 Customer Accounts Receivable	$19,688,011.64
8830-2-0000-10-1101-1421 Customer AR-Misc Billing	$ 1,680,729.91
8830-2-0000-10-1101-1423 A/R Under Collect-Default/LR Sv	$ 2,127,657.97
8830-2-0000-10-1101-1429 A/R REC Obligation	$ 3,675,811.00
Account 142 as of 9/30/2022	$27,172,210.52

The aged accounts receivable listing as of 12/31/2022 includes 44,826 customers and sums to $21,567,622.35. The aging details demonstrate:

Age	# of customers	Total Receivable
Current	40,053	$13,650,488.48
Past due 1-30 days	10,417	$ 2,739,656.85
Past due 31-60 days	6,409	$ 1,698,694.95
Past due 61-90 days	3,872	$ 934,855.91
Past due 91-120 days	3,194	$ 1,317,646.29
Past due 121-150 days	2,624	$ 200,970.90
Past due 151-365 days	2,073	$ 591,219.46
Past due over 365 days	858	$ 466,146.87
	69,500	$21,599,679.71

Audit was unable to tie the aged accounts receivable listing to any account within the general ledger. When asked, Liberty noted that the "*aged trial balance report did not tie out exactly to the general ledger, but it was determined that the variance was immaterial. We have since developed additional reports to clarify differences (mostly due to timing), but these reports* *were not available in December 2022.*" Audit was then provided with a reconciliation without explanation.

AR Debit balances	$19,814,926.03
AR Credit balances (aka Unapplied Payments)	$ (609,186.12)
Total AR	$19,205,739.91

A different portion of the reconciliation reflected Total AR of $19,212,094.38 which was calculated to reflect a variance from the reported $19,205,739.91 of $6,354.47 or 0.03%. While Audit agrees that a percentage variance of 0.03% is immaterial, none of the components within the reconciliation could be verified to the general ledger provided to Audit. **Audit Issue #9**

Refer to the ***Unapplied Payments*** portion of this report, account 242.

Audit also noted four additional SAP Accounts Receivable accounts that were not included within the #142 figure above:

Salaries and Wages	1420	50000010142000	$ 2,472.80
Other Operating Exp	1420	50500010142000	$ -0-
BS LB Offset	1420	70200010142000	$(13,353.12)
WBS ST Lbr-Intrc	1420	85400010142000	$ 29,179.04
			$ 18,298.72

In response to clarification regarding these four accounts, the Company noted that at the set-up of the SAP, the accounts to which these specific accounts' transactions would "settle" were miscoded to the Accounts Receivable. Each was reported to have settled to FERC account 920. Refer to the *Operations and Maintenance* portion of this report. **Audit Issue #1**

Other Accounts Receivable #143 $699,313.90

Audit verified the 12/31/2022 balance on the FERC Form 1 to the following SAP accounts:

Other AR	1430	11303010143000	$ 872,782.97 no change 9/22 – 12/22
Ener Eff Loan Rec	1430	11303510143000	$ 841,012.93
Inc Tax Receivable	1430	14601010143000	$(1,014,482.00) Refer to *Tax* section
			$ 699,313.90

Accounts Receivable from Associated Companies $964,071,909

Filed schedule 1604.01(a)(1)(a) BS reported the above listed total. The following represents the general ledger account balances, as of 12/31/2022:

Interco AR	11101010146000	$ 391,133,658
Interco AR - Legacy	11102010146000	$ 572,938,250
Total (rounded)		$ 964,071,909

The filed total was verified to the FERC Form 1 in that the AR from Associated companies balance was netted with the AP to Associated Companies:

	FERC Form 1	SAP	Variance
Account #146	$ -0-	$ 964,071,908.63	$(964,071,908.63)
Account #234	$(75,125,573.00)	$(1,039,197,481.56)	$ 964,071,908.56
		$ (75,125,573.93)	

Audit noted that the filed schedule reflected an overall balance sheet that included a $(75,125,573.93) variance. For details regarding the variances between the FERC Form 1 balance sheet accounts, refer to **Audit Issue #1.**

The general ledger account balances included in the total filed amount of $964,071,909 were from the intercompany accounts used to record the daily intercompany receivable entries. These receivable entries, such as the cash from customers, are received at the Service Company level—which the Company explained is a separate entity in their accounting system. The AR balance is cleared through an intercompany entry between Granite State and the Service Company. Audit confirmed the that entries to record customer billings were offset to account 11001010142000, Customer AR CIS Ctrl. Refer to the *Accounts Payable to Associated Companies* section of the report for details regarding the GP account settlement of intercompany activity.

Prepayments Account #165 $1,384,677

The filing schedules RR-4.1 and RR-4.2 reflect the total prepayments figure of $1,915,251 as of 12/31/2022. The FERC Form 1 reflects $1,384,677.

Audit verified the September 2022 balances to two general ledger accounts:

8830-2-0000-10-1240-1650 Prepaids	$ 81,450.02
8830-2-0000-10-1240-1653 Prepaid Taxes-Mun-Property-Oper	$736,912.87
Balances as of 9/30/2022	$818,362.89

Each account balance was rolled into SAP accounts 14090010165000, Other Prepaids, and 14081010165000, Prepaid Property Tax. At year end, the balances were:

14090010165000, Other Prepaids	$ 107,887.91
14081010165000, Prepaid Property Tax	$1,276,788.72
Total Prepaids	$1,384,676.63

The 1604.01(a)(1)(a)BS, Bates page I-007 does accurately reflect the prepaid account 165 to be $1,384,676.63.

The variance of $530,574 between the FERC Form 1 and RR-4.1 and RR-4.2 was reported to be SAP accounts, originally mismapped to account 184, but reflected in account 165 on the filing

14023010184000 Billable Interco Clg	$129,595	
14024010184000 Billable Clg	$398,803	
14025010184000 P Card Clearing	$ 2,176	
	$530,574	**Audit Issue #1**

The FERC Form 1 shows a total Clearing Account balance in account #184 of $1,052,518, which is the sum of 7 specific SAP accounts. SAP reflected an additional 33 accounts that sum to $89,572.70, all of which were identified by the Company to have been excluded from account 184 on the FERC Form 1 and included within expense account 920, Administrative and General Salaries. **Audit Issue #1**

DOE Staff requested, in Data Request 4-7, for a list of prepayments and balances by month by major category. The following shows a high level summary from the Company's response to Date Request 4-7.

Total Software	$ 107,889.00
Taxes	$ 1,276,788.72
Clearing Account Entries	$ 530,573.99
Reconciling Items to RR-4.2	$ (1.09)
Total	$ 1,915,250.62

In their response to the Data Request, Liberty noted a minor difference of $1,255 between filing Schedule RR-4.2 and the detailed data. The Company noted they will consider this in their next update of the revenue requirement.

Unamortized Debt Expense Account #181 $14,655

The 2022 Unamortized Debt Expense totaled $14,655 on the FERC Form 1, as well as on the filed schedule 1604.01(a)(1)(a) BS. The amount was verified to the following general ledger account balances, as of 12/31/2022:

Account	Description	Balance
18922010181000	Interco Dfrd Fin	$ 11,447.72
18914010181000	Unamort Debt Exp	$ 3,207.75
	Total Unamortized Debt Exp	$ 14,655.47

The account 1892201081000 was mapped from GP account 8830-2-0000-10-1936-1000, Deferred Financing-Intercompany. Audit confirmed that the GP September balance of $12,592.52 rolled into SAP account 1892201081000. There were no journal entries recorded on the GP account between January – September 2022 and Audit verified that the $12,592.52 reflected the beginning balance forward. On the SAP account there were three monthly credit entries of $95.40 during October – December for the intercompany deferred financing, as well as one debit entry of $11,733.92. The debit was for the reclassification—from account 18922010186000, Misc Deferred Debits—for the monthly deferred financing from January – September 2022 that should have been booked to the deferred financing intercompany GP account. Refer to the ***Interest on Debt to Associated Companies*** section of the report for details regarding the intercompany deferred financing.

The account 18914010181000 was mapped from GP account 8830-2-0000-10-1931-1810, Unamortized Debt Expense. Audit confirmed that the GP September balance of $3,862.53 rolled into SAP account 18914010181000. There were monthly credit entries on the account that were associated with obtaining the First Colony Bonds. Offsetting debit entries were booked to GP account 8830-2-0000-80-8541-4280, Amortize Debt Discount and Expense, which was mapped to SAP account 56104010428000, Amrt Fn Cst-Debt Dis. Refer to the *Long Term Debt* and *Amortization of Debt Discount and Expense* sections for further details.

Other Regulatory Assets $4,557,561

The 2022 FERC Form 1 reflects total Other Regulatory Assets in account 182.3 as $4,557,561. The SAP 12/31/2022 1823 accounts sum to $5,813,867.39. Audit requested clarification of the variance of $(1,256,306.39) and was informed of the SAP set-up settlement issue described earlier. **Audit Issue #1**

3071 LU Granite State Electric OCOA/13010 13010(	CRA-Pnsn&PostEmp Ber	1823	13010010182300	$	2,056,720.25	
3071 LU Granite State Electric OCOA/13080 13080(	CRA Fuel&Commod Cos	1823	13080010182300	$	(3,582,940.43)	
3071 LU Granite State Electric OCOA/13110 13110(	CRA R8 Adj Mech	1823	13110010182300	$	3,273,667.00	
3071 LU Granite State Electric OCOA/13160 13160(	CRA Oth Reg Ast	1823	13160010182300	$	110,538.53	
3071 LU Granite State Electric OCOA/13160 13160(	CRA Oth Reg Ast	1823	13160010182302	$	164,689.52	
3071 LU Granite State Electric OCOA/17010 17010(	LTRA Pen&PostEmp Ber	1823	17010010182300	$	1,669,609.39	
3071 LU Granite State Electric OCOA/17090 17090(	LTRA Inc Tax	1823	17090010182300	$	518,774.83	
3071 LU Granite State Electric OCOA/17110 17110(	LTRA Adj Mech	1823	17110010182300	$	-	
3071 LU Granite State Electric OCOA/17120 17120(	LTRA R8 Case Cost	1823	17120010182300	$	22,127.50	
3071 LU Granite State Electric OCOA/17150 17150(	LTRA Storm Cost	1823	17150010182300	$	-	
3071 LU Granite State Electric OCOA/17160 17160(	LTRA Cost of Rem	1823	17160010182300	$	-	
3071 LU Granite State Electric OCOA/17170 17170(	LTRA Oth Reg Ast	1823	17170010182300	$	158,512.72	
3071 LU Granite State Electric OCOA/24080 24080(	CRL Fuel&Commod Cos	1823	24080010182300	$	833,043.45	exclude in full from 182.3, included with 254 on FERC Form 1
3071 LU Granite State Electric OCOA/50000 50000(	Salaries and Wages	1823	50000010182300	$	884,954.96	exclude ($1,081.00) from 182.3, include in 920
3071 LU Granite State Electric OCOA/50030 50030(	Outside Svs	1823	50030010182300	$	126,253.43	exclude ($1,411.98), $53,144.70, $37,141.25, and include in 920
3071 LU Granite State Electric OCOA/50123 50123(	Fleet-Permit/Inspect	1823	50123010182300	$	25,839.23	
3071 LU Granite State Electric OCOA/50500 50500(	Other Operating Exp	1823	50500010182300	$	174,587.70	exclude $2,380.00 from 182.3, include in 920
3071 LU Granite State Electric OCOA/70200 70200(	BS Lbr Offset	1823	70200010182300	$	(886,035.96)	
3071 LU Granite State Electric OCOA/70203 70203(	BS Services Offset	1823	70203010182300	$	(37,379.46)	
3071 LU Granite State Electric OCOA/70204 70204(	BS Other Offset	1823	70204010182300	$	326,743.96	
3071 LU Granite State Electric OCOA/70205 70205(	BS Fleet Offset	1823	70205010182300	$	(25,839.23)	
				$	**5,813,867.39**	
	included in acct 254 on FERC		24080010182300	$	(833,043.45)	
	included in acct 920 on FERC		50000010182300	$	1,081.00	
	included in acct 920 on FERC		50030010182300	$	1,411.98	
	included in acct 920 on FERC		50030010182300	$	(53,144.70)	
	included in acct 920 on FERC		50030010182300	$	(37,141.25)	
			50500010182300	$	(2,380.00)	
	Additional accounts to include in 182.3 balance:					
	LTRA R8 Case Cost	**186**	**17120010186000**	$	165,861.82	removed from account 186
	Cost Alloc to Cap	**922**	**50510010922000**	$	(316,613.20)	removed from account 922
	Cost Alloc to Cap	**922**	**50510010922000**	$	(182,338.46)	removed from account 922
			FERC pdf pg 26 line 72	**$**	**4,557,561.13**	

Preliminary Survey and Investigative Charges Account #183 $310,019

Audit verified the $310,019.47 Preliminary Survey and Investigative balance on line 73 of the 2022 FERC Form 1 balance sheet to SAP regulatory general ledger accounts 10183000:

Account #	Account Name	Amount
15050010183000	Facility Costs	$ -0-
18980210183000	Prelim. Survey and Invest. Charges	$310,019
50030010183000	Outside Services	$ 37,500
70203010183000	BS Services Offset	$ (37,500)
	Total	$310,019

There were no Preliminary Survey and Investigative charges included on the revenue requirement filing schedules. The GP account 8830-2-0000-10-1615-1830 had a September 30, 2022 balance of $272,519 which was rolled into the SAP account 18980210183000. The GL activity consisted of investigation of new facility costs that rolled from the Great Plains system into the 18980210183000 SAP account. The 15050010183000 Facility Costs account did not have any activity.

The Company indicated there are two settlement accounts that always net to zero: the Outside Services account 50030010183000 go through a settlement and the Outside Services Offset account 70203010183000 creates a credit. The final posting of settlement accounts is then reflected in the 18980210183000 Preliminary Survey and Investigative Charges account. Audit sampled a $37,500 Burns and McDonnell Engineering Company September 30, 2022 invoice that was part of the settlement charges and finally moved to the 18980210183000 account on December 31, 2022. The charges on the invoice were for the contract award, construction analysis, buildout plan, and issuance of final report. The Company indicated that the project will be completed in 2023 construction year.

Accrued Revenues #173 $3,002,394

Audit verified the FERC Form 1 balance sheet Accrued Revenue figure to SAP account 11010010173000, Unbilled Revenue.

The roll forward of Great Plains account 8830-2-0000-10-1162-1730, Accrued Utility Revenue, $1,748,164.16 was noted in the SAP account above. Refer to the ***Revenue*** section of this report for additional information.

Deferred Assets-Storm #1825 $-0-

Great Plains general ledger account 8830-2-0000-10-1930-1825, Storm Costs at 9/30/2022 was $1,604,126.08. Audit verified that that figure was rolled into SAP account 17150010182300, which was zeroed by year-end. This account is part of an annual rate review and audit, and was not reviewed as part of this rate case audit. The 2022 Storm Cost audit report, in docket DE 23-035, was issued on August 17, 2023.

Equity $(147,811,392) and Liabilities $(32,000,000)

The following depicts filed schedule 1604.01 and the FERC Form 1 totals for the Capital:

Account Description		Per 1604.01		Per FERC Form 1
Common Stock	$	(99,024,903)	$	(6,040,000)
Other Paid-in Capital		-		(92,984,903)
Retained Earnings		(45,528,745)		(44,680,599)
Accumulated Other Comprehensive Income		(3,257,744)		(3,257,743)
Total Proprietary Capital	$	(147,811,392)	$	(146,963,245)

Audit noted a variance of $848,147 in the total proprietary capital, as reported on the filed schedule 1604.01 and the FERC Form 1. The variance resulted from the retained earnings filed of $(45,528,745) on schedule 1604.01 versus the retained earnings reported of $(44,680,599) on the FERC Form 1. The Company confirmed that, *"The capitalization per the 1604.01(a)(1)(b) BS includes the 2022 Net Income per the 1604.01(a)(1)(b) IS which was prepared prior to the adjustments to correct for incorrect regulatory accounts and unsettled WBS transactions."* Refer to the Retained Earnings $(45,528,745) section of the report for further details regarding the variance.

The capitalization was verified to the following general ledger accounts:

SAP GL Account	Account Description		12/31/22 Balance
31010010201000	Common Shares	$	(82,024,903)
33500010211000	Additional Paid-in Capital		(17,000,000)
34100010216000	Retained Earnings		(32,931,729)
Net activity all revenue and expense accounts 2022			(11,748,870)
		$	(143,705,501)
36201010219000	AOCI Pension Tax	$	(1,351,471)
36203010219000	AOCI-OPEB Tax		906,817
36204010219000	AOCI-Pension		4,260,428
36206010219000	OCI Pension FAS 158		(2,757,297)
36207010219000	AOCI OPEB		(2,613,808)
36208010219000	AOCI OPEB FAS 158		(3,347,404)
36209010219000	OCI Pension Tax		1,644,991
	Adjustment to Retained Earnings	$	(3,257,744)
	General Ledger Total Capitalization	$	(146,963,245)

Common Stock $(99,024,903)

The filing schedule 1604.01 reported the Common Stock total of $(99,024,903), as of December 31, 2022. The amount was verified to the FERC Form 1 for the total Common Stock Issued $(6,040,000) and Other Paid-in Capital $(92,984,903). Audit understands that—for presentation purposes on the FERC Form 1 only—the Company depicted a consolidated Other Paid-in Capital $(92,984,903), as represented by the following general ledger account balances, less the par value $6,040,000 of Common Stock: account 310100, Common Stock $(82,024,903) and account 335000, additional Paid-in Capital $(17,000,000). As at December 31, 2022, there were 60,400 common shares issued and outstanding. One hundred percent of the authorized issuance of common shares is owned by Liberty Energy Utilities (New Hampshire) Corp. with a par value of $100.00 per share. Audit verified that the reported common stock of $(6,040,000) and other paid-in capital of $(92,984,903) has not changed since the 2018 test-year audit, docketed as DE 19-064.

Other Paid-in Capital $0

There was no amount reported on the filed schedule 1604.01 for Other Paid-in Capital. The FERC Form 1, line 7, reported the figure as $(92,984,903). The 12/31/2022 balance on the general ledger for SAP account 335000-10211000, Additional Paid-in Capital, totaled $(17,000,000). Audit noted that the general ledger balance has not changed since the 2018 test-year audit, docketed as DE 19-064. Refer to the *Common Stock $(99,024,903)* section of the report for details regarding the filed balance for the paid-in capital versus the general ledger and FERC Form 1.

Retained Earnings $(45,528,745)

The filed schedule 1604.01 listed the total Retained Earnings as $(45,528,745). The FERC Form 1 reported a 12/31/2022 retained earnings balance of $(44,680,599). Audit noted the $848,146 variance between the retained earnings filed and the FERC Form 1. The Company explained that *"The variance of $848,146 in the retained earnings balance is due to the variance in the Net Income reported on the FERC Form 1, Page 117, line 78 and the filed 1604.01 (a)(1)(a) PL, page 2 of 2, which is carried forward to retained earnings. These differences are the result of corrections identified in the preparation of the FERC Form 1 after our parent company's annual report was issued. Through discussions with our external auditors, it was determined that the FERC Form 1 would remain consistent with the results included in the APUC annual report. The 1604.01 (a)(1)(a) PL was updated to reflect the correct results for those items identified."*

The Retained Earnings adjustment of $(3,257,744) was verified to the SAP general ledger accounts for the Accumulated Other Comprehensive Income (AOCI). Refer to the *Equity and Liabilities* section of the report for details.

Audit reviewed the activity in each of the AOCI accounts for the test year 2022. Adjustments were reported to be based on actuarial reports, amortization expenses for pension and OPEB, pension true up and tax entries—as well as entries for the GP balance reclass to SAP account 10219000. Additional information relating to pension and OPEB are included within the Payroll section of this report.

Long-Term Debt $(32,000,000)

The filed schedules RR-5.1 and 1604.01 each reported the total long-term debt balance of $(32,000,000), which was confirmed to the FERC Form 1. The following represents the FERC Form 1 balances for the Company's long-term debt obligation, as reported since the prior rate case for the test-year 2018:

Account	Description	12/31/2019	12/31/2020	12/31/2021	12/31/2022
223	Advances from Associated Companies	$ (17,000,000)	$ (17,000,000)	$ (17,000,000)	$ (17,000,000)
224	Other Long-term Debt	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)	$ (15,000,000)
	Total Long-Term Debt	$ (32,000,000)	$ (32,000,000)	$ (32,000,000)	$ (32,000,000)

Advances from Associated Companies #223 $(17,000,000)

Filed schedule RR-5.1 detailed the Company's reported $17,000,000 of outstanding promissory notes payable to Liberty Utilities, as of 12/31/2022:

Date Issued	Maturity	Rate	Principal	Annual Interest
12/21/12	12/20/27	4.89%	$ 1,545,455	$ 75,573
12/21/12	12/20/27	4.89%	$ 4,121,212	$ 201,527
12/21/12	12/20/23	4.49%	$ 7,898,990	$ 354,665
12/20/17	12/20/32	4.22%	$ 3,434,343	$ 144,929
			$ 17,000,000	$ 776,694

The outstanding balance of $(17,000,000) was verified to SAP general ledger account 25100010223000, Notes P-Intrco Leg. Audit recalculated the interest rate for each of the four notes payable and verified the annual intercompany interest amount of $776,694 that was paid on long-term debt during the test-year 2022. Audit confirmed that the annual interest expense was debited as monthly journal entries of $64,724.49 on the GP interest expense account 8830-2-0000-80-8543-2603, Intercompany Interest Expense-LU Co., for the 1st – 3rd quarters of the test-year 2022—with the remaining 4th quarter entries booked to SAP account 10430000. The offsetting entries were booked as credits to GP general ledger account 8830-2-0000-20-2170-2603, Intercompany Interest Payable – LU Co., which is mapped to SAP account 10234000.

The annual interest amount for the $17M in promissory notes—which totaled $776,694—was verified to the FERC Form 1. The filed schedule 1604.01(a)(24) reported the 2022 annual intercompany interest of $711,969 and Audit noted the variance of $64,725 between the filed amount and the FERC Form 1. The Company explained that the variance *"[...] is due to the timing of when the interest payments are typically paid, which is in January and July. This results in a one-month variance between the accrual in the payable account compared to the expense account."* The reported intercompany interest payment for each note was verified to supporting information provided by the Company and Audit confirmed the calculation for the monthly intercompany interest on each of the notes.

Other Long-Term Debt #224 $(15,000,000)

Filed schedule RR-5.1 reported that, as of 12/31/2022, the Company had totaled $15,000,000 in unsecured long-term notes. The following depicts the details for each of the outstanding notes:

Date Issued	Maturity	Lender	Rate	Principal	Annual Interest
11/01/93	11/01/23	First Colony Life-1	7.37%	$ 5,000,000	$ 368,500
07/13/95	07/01/25	First Colony Life-2	7.94%	$ 5,000,000	$ 397,000
05/15/98	06/15/28	Paul Revere Life	7.30%	$ 5,000,000	$ 365,000
				$ **15,000,000**	$ 1,130,500

Audit verified the 12/31/2022 balance of $(15,000,000) to SAP general ledger account 10224000, Other Long Term Debt. Audit noted that the balance on the general ledger—mapped from GP account 8830-2-0000-20-2910-2240—has remained the same since the prior rate case for the test-year 2018. The interest paid on the long-term debt for the test-year 2022 totaled $1,130,500. Audit recalculated the annual interest rate for each note and confirmed that the $1,130,500 was booked to SAP account 10427000, Interest on Long-Term Debt, with the offsetting entry booked to SAP account 10237000, Interest Accrued Long-Term Debt. Refer to the *Interest on Long-Term Debt* section of the report for further details on the monthly interest expense.

Obligations Under Capital Leases – Non-Current #227 $0

The FERC Form 1 and filed schedule 1604.01 reported no balance for the Obligations Under Capital Leases – Non- Current. The account had previously represented the long-term portion of the lease agreement for printers located in the Londonderry, NH facility; however, Audit noted that there was no account listed on the 2022 GL for the long term lease liability and the Company confirmed that the lease had ended. Audit reviewed the 2021 general ledger for GP account 8830-2-0000-20-2960-2271, Lease Liability Long Term and verified that the final quarterly lease payment was made in March, in the amount of $583, and cleared the January beginning balance on the account. The offsetting entry was confirmed to Plant account 8830-2-0000-10-1616-1012, Right-of-Use Asset. Consequently, there was no balance left on the account for 2021 and 2022. Audit also reviewed the 2019 and 2020 general ledgers for the long term lease liability and noted quarterly journal entries recorded lease payments for the printers in Londonderry. The short-term portion of the lease obligation posted to GP account 8830-2-0000-20-2750-2431, Lease Liability Short Term. Audit confirmed that the combined accounts were offset to Plant account 8830-2-0000-10-1616-1012, Right-of-Use Asset. Refer to the *Obligations Under Capital Leased – Current* for details regarding the current obligation for the leased printers.

Current and Accrued Liabilities

Accounts Payable $(4,513,650)

The filing schedule RR-4 line 41 indicates the total accounts payable figure at $4,513,650. The total was verified to the FERC From 1 and the following SAP general ledger accounts:

20003510232000	AR-Unapplied Payments	$(1,453,915)
20301010232000	Interim Liability	$(3,059,737)
		$(4,513,652)

The review of the FERC 232 general ledger revealed that there was no activity in the account for January through September. Audi questioned why there was no activity and the Company noted that *"The converted balance for unapplied from January – September were loaded to regulatory account 242 instead of 232".* Audit notes that the AR-Unapplied Payments should be accounted for in FERC 242 and not FERC 232.

Documentation provided shows that the September balance that was erroneously loaded to account 242 was in the amount of $(854,868**). Audit Issue #1**

Two journal entries comprise the AR-Unapplied Payments balance of $(1,453,915). The Company noted that *"the first entry in the amount of $(609,186) represents the accrual for unapplied payments (credits on customer accounts, not yet applied to invoices) in December 2022. The second entry in the amount of $(844,729) represents the accrual for unapplied payments not yet processed on the customer accounts (cash received, but not yet applied) for December 2022."*

<u>Accounts Payable to Associated Companies $(1,039,197,481.56)</u>

The filed schedule 1604.01 reported the balance of $(1,039,197,481.56). The balance was verified to the SAP general ledger 10234000, as depicted by the following accounts:

Account	Description		Balance a/o 12/31/2022
201010-10234000	Interco AP	$	(544,878,284.23)
201020-10234000	Interco AP - Legacy	$	(493,607,228.14)
211610-10234000	Interco Interst P-L	$	(711,969.19)
	Total A/P to Associated Companies	$	(1,039,197,481.56)

Audit understands that the GP general ledger—as used prior to October 2022—recorded the settlement of intercompany activity. This activity is represented by the following GP accounts, which are now settled to the appropriate SAP general ledger account 11102010146000, Intercompany Accounts Receivable and account 10234000, Intercompany Accounts Payable:

8830-2-0000-20-2810-2079 Due from Liberty Utilities Canada
8830-2-0000-20-2810-2596 Due to APUC
8830-2-0000-20-2810-2603 Due to LU Co.
8830-2-0000-20-2810-2606 Due to Liberty Energy New Hampshire
8830-2-0000-20-2810-2626 Due to Liberty Utilities America Co.
8830-2-0000-20-2810-2635 Due to COGSDALE
8830-2-0000-20-2810-2639 Due from Liberty Utilities (Central) Services Corp.

The Company confirmed that the aforementioned GP accounts are now the "Legacy" SAP general ledger accounts, as of October 2022. Audit reviewed the GP and SAP balances and confirmed that the GP account balances, as of 9/30/2022, rolled into the SAP balances for the Legacy accounts: 11102010146000, Intercompany Accounts Receivable and 20102010234000, Intercompany Accounts Payable.

The FERC Form 1 reported a balance of $(75,125,573) for the Accounts Payable to Associated Companies. The Company confirmed that the balance was the calculated net from the Accounts Receivable from Associated Companies balance and the Accounts Payable from Associated Companies balance. Refer to the *<u>Accounts Receivable from Associated Companies</u>* section of the report for details regarding the FERC Form 1 reporting and calculation.

Audit reviewed the general ledger for the Intercompany Accounts Payable and noted monthly entries for the allocation of professional fees, as well as for the money pool interest and payments to vendors. Supporting information for the APUC allocation percentage calculation that was applied to the types of indirect costs for the indirect billing was provided, along with the money pool interest calculation information. Audit confirmed that the Due to APUC entries for the allocated indirect costs flowed through the intercompany account and were offset to the Outside Services APUC HO Allocations account. The intercompany corresponding GP and SAP account numbers are referenced in the previous paragraphs of this section. Refer to the *Outside Services Employed* and *Algonquin Power & Utilities Corp (APUC)* sections for details regarding the allocation methodology of APUC indirect costs.

Audit recalculated a sample entry for the monthly money pool interest and verified that the Due to LU entries flowed through the intercompany account 201020-10234000, Due to LU and were offset to account 450400-10430000, Interest on Debt to Associated Companies. Refer to the *Affiliate Service Agreements* and *Interest on Debt to Associated Companies* sections for further details regarding the money pool agreement.

An invoice from Asplundh Tree was verified to the general ledger for vegetation work in the maintenance of overhead lines. Audit confirmed that the sampled vendor payments flowed through the Due to Liberty Energy New Hampshire account, with the offset to Maintenance of Overhead Lines-Trouble. Audit understands that prior to October 2022, vendor payments flowed through the appropriate “Due to” account—such as Due to Liberty New Hampshire—as they were processed by the service Company. Refer to the *Maintenance of Overhead Lines* section of the report for further details regarding vegetation management jobs. Refer to the *Cost Allocation Manual (CAM)* section of the report for details regarding the allocation of shared costs.

Customer Deposits $(1,333,411.59)

The filing schedule RR-4 , line 11 total for Customer Deposits was verified to the general ledger accounts below. The total also agrees with the FERC Form 1.

Cor	Company Code2	G/L Account	GL	G/L Account2	Regulatory	GL - REG	DEC Balance	
3071	LU Granite State Electric	OCOA/246400	246400	Curr Cst Dpst Hld	2350	24640010235000	$	(1,238,402.89)
3071	LU Granite State Electric	OCOA/290400	290400	LT Cst Dpst Hld-Ctrl	2350	29040010235000	$	(1,057,963.22)
3071	LU Granite State Electric	OCOA/290410	290410	LT Cst Dpst Hld-Leg	2350	29041010235000	$	962,954.52
							$	(1,333,411.59)

Audit noted that the balances relating to Customer Deposits, account 235, have been as follows, since the prior test year of 2018, docketed as DE 19-064 $(1,278,349):

2019 $(1,249,583) a decrease of 2% over the prior rate case test year balance
2020 $(1,175,621) a decrease of 6% over the 2019 year-end balance
2021 $(1,206,777) an increase of 3% over the 2020 year-end balance
2022 $(1,333,412) an increase of 10% over the 2021 year-end balance.

Within RR-4 is a proformed debit of $101,109, adjusting the proposed test year balance to $(1,232,303). The adjusted figure would represent an increase over the 2021 year-end balance of 2%. Audit requested:

1. the process Liberty follows in determining if a deposit is required,
2.what caused the fluctuation in the balances,
3. on what basis the proforma was calculated.

In reply, 1. The Company restated Puc 1203.03 regarding the circumstances under which a customer may be required to provide a deposit. The internal procedure was not communicated.

2. The fluctuation in the balance from 2021 to 2022 was reportedly due to the price of energy being significantly higher. 3.The proforma was reported to have been based on the test year 13-month average of customer deposits.

Activity within the GP account 8830-2-0000-20-2113-2350 Customer Deposits account included 4,242 journal entries, with a 9/30/2022 balance of $(1,238,402.89). That figure, as noted in the grid above, was rolled into the SAP account, and no further activity was noted.

Interest Accrued from Customer Deposits posted in the Great Plains ledger to account 8830-2-000020-2116-2370. The September 30, 2022 balance was zero. Activity in the account showed 1,067 journal entries of primarily less than $5. One entry in the amount of $259.59, on 9/27/2022, was identified and clarification of it was requested. Liberty noted that the figure represented monthly interest posting for 241 customers' deposits. The Company noted a miscoding between Granite State Electric and EnergyNorth, which was identified and corrected during the test year. Liberty also noted that they "*discovered a coding error for 57 of the 3,219 GSE accounts with security deposits, which has prevented these customers from receiving their interest. The Company will make the correction and post the missing interest to the customers' accounts. The total amount of security deposits held for these 57 accounts as of December 2022 is $10,530. The estimated deposit interest owed based on the 5.5% rate in effect for that period is $145.*" **Audit Issue #10**

Deferred Assets-Pension/OPEB #228

$(7,293,207) per the filing 1604.01(a)(1)(a) BS was verified to the FERC Form 1 and to general ledger accounts:

Great Plains		SAP		Total	
8830-2-0000-20-2930-2283	OPEB/FAS 106 Benefit Reserve	28012010228300	PBO Opeb Pen/FAS106	$	(5,577,094)
8830-2-0000-20-2930-2285	Long Term Pension Obligation	28003010228300	LT Pension Ob	$	(1,716,113)
				$	(7,293,207)

Audit reviewed, in the *Payroll* section of this report the quarterly pension contributions booked to FERC account 228 without exception.

Additional entries in the accounts include accruals, payments to Benestar, Excellus retirement billings and other. No exceptions were noted.

Interest Accrued #237 $(325,292)

The 12/31/2022 balance for the accrued interest was reported as $(325,292) on the filed schedule 1604.01(a)(1)(a) BS, as well as the FERC Form 1. The amount was confirmed to the SAP general ledger account 211010-10237000, Accrued Interest. The corresponding GP account 8830-2-0000-20-2116-2371 was comprised of 21 journal entries that totaled $(425,416.57), as of 9/30/2022; Audit confirmed that the September 2022 GP account balance rolled into the SAP year-end account balance.

Since the prior rate case for the test-year 2018, the interest accrued balance was reported at $(142,792) for each year, excluding the years 2020 and 2022, when the year-end balance was $(325,292). The supporting documentation was reviewed and Audit confirmed that the reported increase of $(182,500) from the previous year-end balance of $(142,792)—for the years 2020 and

2022—was due to the semi-annual interest for the Paul Revere note that was typically recorded in December, being recorded in January of the following year. The 2021 general ledger was reviewed and Audit confirmed that the 2020 Paul Revere semi-annual interest payment of $182,500 was recorded the following month, on 1/22/2021.

Audit reviewed supporting detail and verified credit entries on the account, in the amount of $63,791.66 and $30,416.67, for the monthly interest accrual on the long term notes from First Colony and Paul Revere, respectively. The offsetting debits were confirmed to GP account 8830-2-0000-80-8546-4270, Fixed Rate Interest Cost, and the equivalent SAP account 56030010427000, Interest Expense-Fixed Rate. Audit verified the journal entry for the reversing debits, recorded semi-annually on 6/16/2022, for the First Colony and Paul Revere notes and on 10/31/2022 for First Colony, with Paul Revere to be recorded in January 2023. Refer to the *Interest on Long-Term Debt* section of the report for details regarding the verification of the interest expense.

Obligations Under Capital Leases–Current #243 $(101,750)

Filed schedule 1604.01(a)(1)(b) BS and the FERC Form 1 each reported the Obligations Under Capital Leases-Current with a balance of $(101,750). The following represents the general ledger account balances, as of 12/31/2022:

210300-10243000	Miscellaneous Accrued Liab	$ (101,750)
246610-10243000	Current Operating Lease Obligation	$ -
	Total Obligations Under Capital Leases-Current	$ (101,750)

The short-term lease obligations were originally charged to GP accounts 8830-2-0000-20-2141-2431, Battery Storage Offset, and 8830-2-0000-20-2750-2431, Lease Liability Short Term. Audit confirmed that the September 2022 balances for both GP accounts rolled into the SAP year-end total of $(101,750).

The prior rate case for the test-year 2018 reported a balance of $0 for the total Obligations Under Capital Leases-Current. Audit noted that the 12/31/2022 credit balance of $(101,750) related to the Battery Storage Pilot Program, which was approved on January 17, 2019 in docket DE 17-189, Order No. 26,209. Specifically, the Order approved "*the costs of the program to participating customers [...as] either an upfront payment of $4,866, or payments of $50 each month for 10 years.*" As of 9/30/2022, Audit confirmed that there were 16 credit entries of approximately $6,000 each on GP account 8830-2-0000-20-2141-2431, Battery Storage Offset and mapped to SAP account 210300-10243000. The entries were for the individual loan billing of customers participating in the Battery Storage Pilot Program and who chose the $50 per month payment option. The Company confirmed that as part of the program, *"[...]customers are charged either $50 per month for ten years, $6,000.00 in total, or they would have paid $4,866.00 upfront for utilization of the batteries in the pilot[...]In 2021 and 2022, the Company collected the upfront payments from customers who chose that option and created the 'loan' for those customers who chose to pay $50 per month over ten years. Those entries were completed periodically, depending on when the customer's final signed contract was received."* Audit verified that the offsetting debit entry was made to GP account 8830-2-0000-10-1160-1439, Other AR-Special Contracts Battery Storage. Audit reviewed the Cogsdale system information for a sample of one of the loans—including the principal amount of $6,000, the corresponding customer ID and loan ID, as well as the monthly customer payment of $50 with the total number of payments identified as 120.

The beginning balance of $(583.33) on account 246610-10243000 represented the current obligation for leased printers that are at the facility located in Londonderry, NH. The Company stated that the operating lease ended in March of 2022. The only transaction recorded on GP account 8830-2-0000-20-2750-2431, Lease Liability Short Term—corresponding SAP account 24661010243000, Current Operating Lease Obligation—cleared out the account for the final quarterly payment of $583.33, recorded on 3/31/2022. Audit confirmed the lease retirement of $583 was reported as offset to Plant account 8830-2-0000-10-1616-1012, Right-of-Use Asset. Refer to the *Obligations Under Capital Leased–Non-Current* for details regarding the long-term portion of the obligation for the leased printers.

Interest Income $(281,962)

The filed schedule 1604.01(a)(1)(a) PL reflected an Interest Income balance of $(281,962). Interest Income is not included within the revenue requirement schedules, as it is a below the line account.

The amount was verified to the FERC Form 1 and the general ledger account balances, as of 12/31/2022:

Account	Description	Balance
47030010419000	Interest Income	$ (259,745.02)
47050010419000	Rental Income	$ (22,217.35)
	Total Interest Income	$ (281,962.37)

The Rental Income recorded on account 470500-10419000 was included in the total Interest Income balance of $(281,962.37). The Company explained that the Interest Income total "[…]*also includes income from two tower rental agreements which were recorded as interest income in error and should have been recorded as rental income."* Audit confirmed the credit entries on SAP rental income account 470500-10419000, in the total amount of $(22,217.35), for the October – December 2022 monthly tower rentals on the AT&T and Sprint towers. Audit noted that the total $(22,217.35) in tower rental income was erroneously recorded to the interest income account. As a result, the Revenue Requirement schedule RR-2.3, account 10454000 is understated. **Audit Issue #11**

The interest income was originally charged to GP account 8830-2-0000-40-4420-4190, Interest Income. Audit confirmed that the September 2022 balance on the account settled into the SAP account 470300-10419000 year-end total of $(259,745.02). The following represents the FERC Form 1 balances for the Company's interest income, as reported since the prior rate case for the test-year 2018:

Account Description	12/31/2019	12/31/2020	12/31/2021	12/31/2022
Interest and Dividend Income	$ (467,804)	$ (262,376)	$ (482,430)	$ (281,962)

The Company explained that *"Most of the interest income is manually calculated on regulatory deferral balances, using the monthly prime interest rate or the interest rate on customer deposits, and recorded to the general ledger."* As such, entries booked on the account included the interest on the deferral balance for the LRAM, stranded costs, and storm costs. Refer to the *Accrued Expenses* section of the report for further details.

Audit also noted credits on the account for the monthly interest on the two Blackrock mutual funds. The Company provided the supporting monthly BlackRock statements, as well as the monthly interest calculation, and clarified that Blackrock is an external investment account that earns interest. The interest is reinvested and recorded to account 470300-10419000, Interest Income and offset to account 188010-10134000, Restricted Cash. Audit verified the monthly journal entries on the general ledger Interest Income account and confirmed the interest calculation to the monthly ending balance for the two funds—as used in the interest calculation—to the bank statements. Refer to the *Cash* section of the report for further details regarding the BlackRock investment.

A 10/1/2022 debit entry of $1,105,060 posted on the Interest Income account and was described as “GSE Parking Lot Entry” for the 4th quarter. The Company clarified that the entry was for the transfer of Q1-Q4 Money Pool interest and provided the calculation, based on the daily interest (earned)/charged. Audit sampled the Q1 pool interest and confirmed the calculation to the general ledger, with the offset entry to 450400-10430000, IC Interest Rev. Refer to the *Interest on Debt to Associated Companies* section of the report for details regarding how the money pool interest is booked.

Interest Expense $(2,503,459)

The 2022 total Interest Expense of $(2,503,459) was reported on the filed schedule 1604.01(a)(1)(1) PL and verified to the FERC Form 1. The following general ledger accounts represent the total Interest Expense for the test-year 2022:

SAP Account	Description		Balance a/o 12/31/2022
10427000	Interest on Long-Term Debt	$	1,130,500
10428000	Amortization of Debt Discount and Expense		2,183
10237000	Interest on Debt to Associated Companies		(4,075,337)
10431000	Other Interest Expense		518,505
10432000	AFUDC-Borrowed Funds (see *Utility Plant* section)		(79,309)
	Total Interest Expense (rounded)	$	(2,503,458)

Interest on Long-Term Debt #427 $1,130,500

The 12/31/2022 balance for the interest on long-term debt was reported as $1,130,500 on the filed schedule 1604.01, as well as the FERC Form 1. Audit noted that the balance has remained the same since the prior rate case for the test-year 2018. As of 9/30/2022, the balance on GP account 8830-2-0000-80-8546-4270, Fixed Rate Interest Cost totaled $847,874.97. Audit verified that the September balance on the former GP account rolled into SAP account 560300-10427000, Interest on Long-Term Debt.

The Company provided copies of the statements from JPMorgan Chase Bank for the debt service, detailing the interest payments for the First Colony and Paul Revere issues, which totaled $15,000,000. The following represents details for the monthly interest calculation applied to the long-term debt:

Date Issued	Maturity	Lender	Rate	Principal		Annual Interest		Monthly Interest
11/01/93	11/01/23	First Colony Life-1	7.37%	$ 5,000,000	$	368,500	$	30,708.33
07/13/95	07/01/25	First Colony Life-2	7.94%	$ 5,000,000	$	397,000	$	33,083.33
								63,791.66
05/15/98	06/15/28	Paul Revere Life	7.30%	$ 5,000,000	$	365,000	$	30,416.67
		Total		**$ 15,000,000**	$	1,130,500	$	94,208.33

Audit confirmed the interest amounts on the Chase bank statements to monthly debits on the account. The interest expense was booked monthly in the aggregate amount of $63,791.66 for both of the First Colony issues and in the amount of $30,416.67 associated with the Paul Revere issue. The offsetting credit entries were confirmed to GP account 8830-2-0000-20-2116-2371, Interest Accrued-LTD and mapped to SAP account 211010-10237000. Audit verified the bi-annual payment accrual debit entries made on 6/1/2022 and 10/31/2022; no true-ups or adjustments were recorded. Refer to the *Other Long-Term Debt* section of the report for further details regarding the monthly interest expense accrual.

Amortization of Debt Discount and Expense #428 $2,183

The filed schedule 1604.01(a)(1)(a) PL reflected an Amortization of Debt Discount Expense that totaled $2,183 for the test-year 2022. The amount was verified to the FERC Form 1 and the SAP general ledger account 561040-10428000, Amortization of Debt Discount and Expense. The prior rate case balance of $2,619 had remained unchanged until 2022, where there was a decrease of $436 in the $2,183 balance reported. The test year 2022 total expense of $2,183 was confirmed to ten debit entries for the monthly amortization expense of $218.26 each, during the months of January through October. Offsetting credit entries were verified as booked to account 189140-10181000, Unamortized Debt Expense. Audit inquired as to why there were no monthly amortization entries for November and December. The Company explained that *"The November and December 2022 entries to record the monthly amortization expense of $218.26 were charged to SAP[...]regulatory account 10920000 in error, instead of 10428000. As a result, $436.52 was reported in the incorrect regulatory account."* Audit noted the November and December amortization expense entries on SAP account 561040-10920000, Amrt Fn Cst-Debt Discount, totaled $436.52 for the two months; thus, the decrease in the expense balance that was reported from 2021 to 2022.

As of 9/30/2022, the balance on GP account 8830-2-0000-80-8541-4280, Amortize Debt Discount and Expense, totaled $1,964.34 and consisted of nine debit entries for the monthly amortization of the debt expense. Audit verified that the September balance on the former GP account rolled into SAP account 561040-10428000.

Audit confirmed the debit transactions on the general ledger to the debt expense amortization information that was provided by the Company. The straight-line method used in the calculation of the amortization was based on the unamortized debt discount balance of $30,694.43 from the Granite State Electric Acquisition Date of July, 2012. Refer to the *Long-Term Debt* section of the report for details regarding the debt.

Interest on Debt to Associated Companies #430 $(4,075,337)

Filed schedule 1604.01(a)(1)(a) PL and the FERC Form 1 each reported a balance of $(4,075,337) for the Interest on Debt to Associated Companies. The following represents the net of four SAP general ledger account balances that comprise the total, as of 12/31/2022:

Account	Description	Balance
50500010440000	Other Operating Exp	$ (1,077,479.83)
45040010430000	IC Interest Rev	$ (3,775,696.14)
56051010430000	Int Exp-IC Leg	$ 713,018.79
56052010430000	Int Exp-IC	$ 64,819.89
	Total Interest on Debt to Associated Companies	$ (4,075,337.29)

Corresponding to the SAP accounts, the GP account 8830-2-0000-80-8543-2603 Intercompany Interest Expense LU Co. and GP account 8830-2-0400-40-4434-2603 Intercompany Interest Income had a 9/30/2022 balance of $583,379.01 and $(1,077,479.83) respectively. The two intercompany interest GP accounts are currently settled to the aforementioned SAP accounts 10430000, Interest on Debt to Associated Companies, as of 10/01/2022. Audit confirmed that the September 2022 GP ending balances were rolled into the SAP year-end account balance of $(4,075,337.29).

Entries on the accounts included interest for the money pool and intercompany debt. The Company described the booking of the money pool interest by stating that, "*Corporate Treasury calculates the Money Pool interest daily, applying the prevailing commercial paper issuance and LIBOR rates, and posts the journal entries on a monthly basis.*" Audit sampled entries on each of the accounts and confirmed that the monthly pool interest on account 450400-10430000 IC Interest Rev., was offset to account 201020-10234000, Interco AP Legacy. Audit noted that the only entry on account 505000-1044000, Other Operating Exp, was in the amount of $(1,077,479.83) for a 12/31/2022 credit—offset to account 450400-10430000, IC Interest Rev—as a reclass entry "to correct Reg Acct" for the August and September 2022 money pool interest. Refer to the *Affiliate Service Agreements* section of the report for details regarding the money pool.

Monthly entries on account 560510-10430000, Int Exp-IC Leg, were for the interest paid on the $17,000,000 in long-term debt. Offsetting entries were confirmed to account 211610-10234000, Interco Interest P-L. An additional $1,145 in interest—posted monthly as $95.40—was booked for the intercompany deferred financing. Audit confirmed the offsetting entries as credits to GP account 8830-2-0000-10-1936-1000, Deferred Financing-Intercompany, which mapped to SAP account 10181000. Refer to the *Advances from Associated Companies* for further details regarding the interest rate for each note of the long-term debt.

Other Interest Expense Account #431 $518,505

The 2022 Other Interest Expense was listed as $518,505 (rounded), per filed schedule 1604.01(a)(1)(1) PL. The FERC Form 1 reported a balance of $518,502 for the account; Audit noted the three dollar variance and deemed it immaterial. The filed amount of $518,505 was confirmed to the SAP general ledger balance on account 56300010431000, Other Interest Expense, as of 12/31/2022. The corresponding GP account 8830-2-0000-80-8550-4310 totaled

$297,319.75, as of 9/30/2022 and Audit confirmed that the September 2022 GP account balance rolled into the SAP year-end account balance.

Transactions on the account included the interest expense that is associated with customer deposits, fees for letter of credit, and the carrying costs calculated on the regulatory deferral balances—such as the storm fund, the RGGI refund, Energy Efficiency, and default energy service. Audit sampled monthly interest expense entries on the regulatory deferral balances and confirmed the offset for the interest to the appropriate current regulatory liabilities account. Refer to the respective program audits—reviewed annually—for further details regarding the interest expenses related to the storm fund, RGGI refund, default service, and energy efficiency program.

Allowance for Funds Used During Construction (AFUDC) $(79,309)

The 2022 AFUDC was listed as $(79,309) per the filed schedule 1604.01(a)(1)(1) PL, as well as the FERC Form 1. Audit verified the total reported to SAP general ledger account 56201010432000, AFUDC Borrowed. The corresponding GP account 8830-2-0000-80-8550-4320 was comprised of 45 journal entries that totaled $(54,633.12), as of 9/30/2022; Audit confirmed that the September 2022 GP account balance had been rolled into the SAP year-end account balance. The AFUDC Equity component was booked to GP general ledger account 8830-2-0000-40-4700-4191, Allowance for Other Funds Used During Construction and mapped to SAP account 47040010419100 AFUDC Equity $(130,600). The general ledger balance for the AFUDC equity was tied to the filed schedule 1604.01(a)(1)(b) PL, as well as to the FERC Form 1. The GP account balance totaled $(90,238.05) as of 9/30/2022 and Audit confirmed that the amount had been rolled into the SAP account balance for the year-end.

The filed schedule RR-5 reported the weighted cost at the annual rate of 4.73% for the Equity component and at the annual rate of 2.87% for the Borrowed component. Audit reviewed information provided by the Company, including the AFUDC calculation and confirmed the weighted cost for the test year 2022. Sampled journal entries for the borrowed and equity portions were tied to the AFUDC calculation. Audit verified that monthly credit transactions posted on each account and were offset to the CWIP 10107000. Refer to the *Plant* section of the report for details regarding the AFUDC detail per work order.

REVENUE $(141,545,195)

The filing schedule RR-2 reflects the test-year revenue as:

Residential Sales	$ (77,521,597)
Commercial and Industrial Sales	$ (61,123,082)
Public Street and Highway Lighting Sales	$ (1,168,888)
Sales for Resale	$ (169,677)
Other Sales	$ 1,018,212
Total Revenue to Ultimate Customers	$(138,965,031) rounded
Miscellaneous Service Revenue	$ (536,454)
Electricity Revenue Rate Increment	$ -0-
Rent from Electric Property	$ (361,375)
Other Electric Revenues	$ (1,682,335)
Decoupling Revenue	$ -0-
Total Other Revenue	$ (2,580,163)
TOTAL REVENUE	**$(141,545,195)**

Audit verified the filing reported test-year ended 12/31/2022 Operating Revenue figure of **$(141,928,329),** to the 2022 FERC Form 1 as follows:

FERC Account per FORM 1	12/31/2021 FERC Form 1	12/31/2022 FERC Form 1	% change 2022 v 2021	12/31/2022 SAP Yr End	FERC vs SAP variance
440	$ (55,533,670)	$ (77,521,597)	**40%**	$ (77,521,596.72)	$ (0.28)
442 small	$ (42,425,000)	$ (54,543,141)	**29%**	$ (54,543,141.33)	$ 0.33
442 lg / ind	$ (7,515,140)	$ (6,579,941)	**-12%**	$ (6,579,941.13)	$ 0.13
444	$ (1,098,244)	$ (1,168,888)	**6%**	$ (1,168,887.52)	$ (0.48)
subtotal	$ (106,572,054)	$ (139,813,567)	**31%**	$ (139,813,566.70)	$ (0)
447	$ (155,523)	$ (169,677)	**9%**	$ (169,677.17)	$ 0.17
449.1	$ 708,219	$ 1,018,212	**44%**	$ 1,018,212.45	$ (0.45)
451	$ (505,695)	$ (536,454)	**6%**	$ (536,453.64)	$ (0.36)
454	$ (341,515)	$ (361,375)	**6%**	$ (361,374.93)	$ (0.07)
456	$ (1,032,561)	$ 355,575	**-134%**	$ 355,574.56	$ 0.44
456.1	$ -	$ (2,421,044)	**#DIV/0!**	$ (2,421,043.73)	$ (0.27)
TOTAL REV	**$ (107,899,129)**	**$ (141,928,330)**	**32%**	**$ (141,928,329)**	**$ (1)**

Audit verified the ending September 2022 Great Plains account balances were rolled into the SAP system accounts (identified below). Those balances were then verified to the FERC Form 1, and to the Revenue Requirement schedules noted.

Great Plains account number, name, balance as of 9/30/2022		SAP verification of 9/30 rollforward			SAP 12/31/2022	FERC Form 1	Filing
8830-2-0000-40-4290-4401	Residential Sales - Fixed Portion	$ (5,038,577.00)	40001010440000	Elec Rev Fx Mtr Res	$ (6,867,775.36)		RR-2.2
8830-2-0000-40-4290-4402	Residential Sales - Variable Portion	$ (23,299,564.76)	40010010440000	Elec Rev Us Mtr Res	$ (29,611,814.51)		RR-2.2
8830-2-0000-40-4290-4403	Residential Sales - Energy Cost	$ (28,384,763.45)	40020010440000	Elec Rev Pt Mtr Res	$ (41,042,006.85)	$ (77,521,596.72)	RR-2.2
8830-2-0000-40-4290-4423	Commercial Sales - Fixed Portion	$ (1,958,442.46)	40002010442000	Elec Rev Fx Mtr ComL	$ (2,680,242.39)		RR-2.2
8830-2-0000-40-4290-4424	Commercial Sales - Variable Portion	$ (23,317,596.94)	40011010442000	Elec Rev Us Mtr Com	$ (30,729,089.74)		RR-2.2
8830-2-0000-40-4290-4425	Commercial Sales - Energy Cost	$ (15,027,548.45)	40021010442000	Elec Rev Pt Mtr Com	$ (21,133,809.20)	$ (54,543,141.33)	RR-2.2
8830-2-0000-40-4290-4426	Industrial Sales - Fixed Portion	$ (181,267.40)	40005010442000	Elec Rev Fx Mtr Ind	$ (191,266.31)		RR-2.2
8830-2-0000-40-4290-4427	Industrial Sales - Variable Portion	$ (4,978,427.18)	40012010442000	Elec Rev Us Mtr Ind	$ (5,390,375.49)		RR-2.2
8830-2-0000-40-4290-4428	Industrial Sales - Energy Cost	$ (920,212.09)	40022010442000	Elec Rev Pt Mtr Ind	$ (998,299.33)	$ (6,579,941.13)	RR-2.2
8830-2-0000-40-4290-4441	Public Street&Highway Lighting - Fixed	$ (643,254.65)	40006010444000	Elec Rev Fx Mtr Pub	$ (806,159.04)		RR-2.2
8830-2-0000-40-4290-4442	Public Street&Highway Lighting-Variable	$ (137,164.82)	40013010444000	Elec Rev Us Mtr Pub	$ (177,278.13)		RR-2.2
8830-2-0000-40-4290-4443	Public Street&Highway Lighting - Energy	$ (130,279.15)	40023010444000	Elec Rev Pt Mtr Pub	$ (185,450.35)	$ (1,168,887.52)	RR-2.2
8830-2-0000-40-4290-4473	Sale for Resale - Fixed Portion	$ (285.52)		Elec Rev for Resale			
8830-2-0000-40-4290-4474	Sale for Resale - Variable Portion	$ (71,895.35)	40032010447000	all 3 accounts rolled to			
8830-2-0000-40-4290-4475	Sale for Resale - Energy Cost	$ (97,496.30)		1 SAP $(169,677.17)	$ (169,677.00)	$ (169,677.00)	RR-2.2
8830-2-0000-40-4290-4491	Prov for rate refunds	$ 2,358,017.56	40033010449100	Elec Rev Other	$ 1,018,212.45	$ 1,018,212.45	RR-2.2
8830-2-0000-40-4210-4510	Misc Service Revenues	$ (189,977.64)	40033010451000	Elec Rev Other	$ (478,838.64)		RR-2.3
8830-2-0000-40-4210-4511	Misc Ser Rev-Open Access DSM	$ (288,841.00)		combined into SAP	$ (57,615.00)	$ (536,453.64)	RR-2.3
8830-2-0000-40-4210-4561	Other Electric Revenue - Decoupling	$ (1,760,924.00)	400300104561000	Elec Rev Dis Cap Ch	$ (2,420,829.00)		RR-2.3
8830-2-0000-40-4460-4951	Decoupling Revenue	$ -					
			40039010456100	Ener Rev Other Res	$ (214.73)	$ (2,421,043.73)	RR-2.3
			40033010407300	Elec Rev Other	$ (383,134.66)	**Audit Issue**	**RR-2.13**
8830-2-0000-40-4210-4563	Other Elec Rev-Open Access Rev-Dstrbtn	$ 348,364.96	40030010456000	Elec Rev Dis Cap Ch	$ 653,316.84		RR-2.3
			40033010456001	Elec Rev Other	$ (228,257.62)		
8830-2-0000-40-4210-4520	Electricity Rev - Rate Increment	$ 319,010.00	40033010456000	Elec Rev Other to SAP	$ 313,650.00		RR-2.3
8830-2-0000-40-4210-4560	Other Electric Revenue	$ (5,360.00)		$313,650.00		$ 355,574.56	
8830-2-0000-40-4210-4540	Rental Income	$ (285,213.40)	40033010454000	Elec Rev Other	$ (361,374.93)	$ (361,374.93)	RR-2.3
						$ (141,928,328.99)	

Based on a review of the FERC Form 1, and the general ledger accounts that support that figure, the revenue in the filing is understated by $(383,135). Audit noted account OCOA/400330 Electric Revenue-Other, 10407300 $(383,135) on the Depreciation and Amortization Revenue Requirement schedule RR-2.12, line 8. The Company did proform it out of the Depreciation and Amortization schedule, but did not proform it into RR-2, RR-2.2, or RR-2.3. **Audit Issue #12**

Account 440 on the FERC Form 1, Residential Sales was verified to SAP year-end balances in:

40001010440000 $ (6,867,775.36) Fixed Portion
40010010440000 $(29,611,814.51) Variable Portion
40020010440000 $(41,042,006.85) Energy Cost
Residential $(77,521,596.72) represents a 40% increase in sales over the 2021 year-end balance.

Account 442 on the FERC Form 1, Small Commercial Sales was verified to SAP year-end balances in:

40002010442000 $ (2,680,242.39) Fixed Portion
40011010442000 $(30,729,089.74) Variable Portion
40021010442000 $(21,133,809.20) Energy Cost
Small Commercial $(54,543,141.33) represents a 29% increase in sales over the 2021 year-end balance.

Account 442 on the FERC Form 1, Large Commercial and Industrial Sales was verified to SAP year-end balances in:

40012010442000	$ (5,390,375.49)	Fixed Portion
40005010442000	$ (191,266.31)	Variable Portion
40022010442000	$ (998,299.33)	Energy Cost
Small Commercial	$ (6,579,941.13)	represents a 12% decrease in sales over the 2021 year-end balance.

Account 444 on the FERC Form 1, Public Street and Highway Lighting Sales was verified to SAP year-end balances in:

40006010444000	$ (806,159.04)	Fixed Portion
40013010444000	$ (177,278.13)	Variable Portion
40023010444000	$ (185,450.35)	Energy Cost
Small Commercial	$ (1,168,887.52)	represents a 6% increase over the 2021 year-end balance.

Account 447 on the FERC Form 1, Sales for Resale $(169,677) was verified to one SAP account, 40032010447000, Elec Rev for Resale.

Account 449.1, Provision for Rate Refunds, $1,018,212.45 on the filing RR-2 as Other Sales, was verified to the SAP account 40033010449100.

Audit verified each of the reported Other Revenue amounts on the supporting schedule RR-2.3, and subsequently to the referenced regulatory SAP general ledger accounts included on that schedule.

Within the FERC Form 1 was the identification of Border Sales in the amount of 970 megawatt hours. The DoE, via data request 5-21, asked "… *Please provide a detailed explanation of the information contained in this schedule regarding energy sales "Massachusetts Electric – Border Sales including how sale costs for this energy are established.*" The Company responded "…*The energy sales identified as "Massachusetts Electric – Border Sales" represent borderline sales, or Sales for Resale, to certain residential and commercial customers of National Grid located in Massachusetts who receive electric service from Liberty due to their proximity to Liberty's service area. The customers are billed monthly in accordance with a FERC Electric Tariff based on the Retail Delivery Service tariffs that the Company would apply to the retail locations served under the tariff if those retail locations were within the Company's service territory.*"

Audit had requested clarification of how the Cogsdale and SAP billing systems differentiate the Border Sales customers, how many customers are included in the Border Sales, and what rate classes. The Company indicated that in Great Plains there are approximately 170 customers in rate 41-ERD05NG. The customers are included in D05 in SAP, reported as one Sales for Resale-Residential. There are 10 commercial accounts billed as rate G3, reported as on Sales for Resale-Commercial. FERC Form 1, page 311 indicates the total Massachusetts Electric border sales was $169,677. That figure agrees with the Electric Operating Revenues schedule account 447, Sales for Resale.

Other Revenues

The Miscellaneous Service Revenue $(536,454) per the FERC Form 1 and the filing schedule RR-2.3 was tied to two SAP line items:

40033010451000	$(478,838.64)	8830-2-0000-40-4210-4510 Misc Service Rev
40033010451002	$ (57,615.00)	not in mapping in Puc 1604 section of the filing
	$(536,453.64)	

Audit reviewed the Great Plains January through September activity, over 6,000 entries of primarily $20 service charges in account 8830-2-0000-40-4210-4510, Miscellaneous Service Revenues. For that period, revenue recorded summed to $(189,977.64). Audit also reviewed 8830-2-0000-40-4210-4511, Miscellaneous Service Revenue-Open Access DSM, which for the January through September period summed to $(288,841.00). That account represents the Energy Efficiency Incentive calculated. Combined, these two accounts sum to $(478,828.64).

Within the SAP 40033010451000, Misc Serv Revs-Sls of Electy-FERCE, are monthly entries from January through October, which agree with the sum of both accounts' Great Plains activity, $(478,818.64). One journal entry in October, in the amount of $(20.00) reflects the full revenue of $(478,838.64). Activity was then noted in October, November, and December in account 40033010451002, Energy Efficiency Incentive. Three equal entries of $(19,205) each summed to $(57,615). From January through September, estimates of the incentive were posted to Misc Ser Rev-Open Access DSM 8830-2-0000-40-4210-4511.

Rent $(361,374.93) per the FERC Form 1 was verified to SAP account 40033010454000. The figure was included within the Revenue Requirement filing schedule RR-2.3. The January through September Great Plains account was 8830-2-0000-40-4210-4540, Rental Income. Audit verified that the monthly entries from January through September 2022 were converted into SAP for those months. The October through December entries were also reviewed.

The rental income represents utility pole and/or cable attachments, total for the reported t27 specific rental agreements. Audit requested and was provided with each agreement, originally excluding the number and type of attachments. Subsequent agreements did reflect the actual attachment details. Refer to **Audit Issue #11** which discusses an error with posting $(22,217.35) of rental income from AT&T and Sprint to Interest Income SAP account 47050010419000.

Other Electric Revenues $(1,682,334.51) per the filing RR-2.3 was verified to five SAP accounts:

40030010456000 Elec Rev Dis Cap Chg	$ 653,316.84	RR-2.3
40033010456000 Elec Rev Other	$ 313,650.00	RR-2.3
40033010456001 Elect Rev Other SOE Rate Increment	$ (228,257.62)	RR-2.3
40030010456100 Revs fm Tnmsn of Elec of Others	$(2,420,829.00)	RR-2.3
40039010456100 Revs fm Tnmsn of Elec of Others	$ (214.73)	RR-2.3
	$(1,682,334.51)	

$653,316.84 was reviewed in both the Great Plains account 8830-2-0000-40-4210-4563, Other Elec Rev-Open Access Rev-Distribution and the SAP accounts noted above. The activity reclassified revenues out of account 456x, and into Great Plains 8830-2-0000-20-2141-2422, Current and Accrued REP/VMP Provision and 8830-2-0000-10-1168-1821, Current Regulatory Asset-Special Audit. Those -1821 entries related specifically to the Property Tax Adjustment Mechanism (PTAM).

Schedule RR-2, line 15, Decoupling Revenue shows zero for the test year relating to FERC account 495. As part of the RDAF audit conducted by the Department of Energy Enforcement division (DE 22-052), Audit noted that from July 2021 through March 2022, decoupling entries were booked to 8830-2-0000-10-1169-1828, Deferred Decoupling Asset, and offset to 8830-2-0000-40-4460-4951, Decoupling Revenue. Beginning in March 2022, the revenue account -4460-4951 was cleared to 8830-2-0000-40-4210-4561, and all subsequent monthly revenue entries posted to that account. Per Order 26,619 in docket DE 22-018, the revenue decoupling adjustment clause was to be included in the transmission charge annual rate filing for reconciliation. It appears that the account number change is the result of Liberty interpreting the Order in that way.

Audit specifically verified the $(2,420,829) revenue on line 9 of RR-2.3, Revs fm Tnmsn of Electy of Othrs-Sls of Electy represents the revenue side of monthly revenue decoupling entries calculated to account for the difference between "actual revenue per customer" vs. "target revenue per customer". The offsetting entry posts to balance sheet account 131100 CRA R8 Adj Mech 10**182**300. $(1,760,924) of the total represents the net decoupling revenue January through September 2022, which agreed with Great Plains as of 9/30/2023. The remaining $(659,905) revenue represents net decoupling revenue October through December 2022 per SAP.

$(214.73) was verified to SAP account 4003901045610 as well, with the journal entry type listed as "CS", which within SAP stands for FICA CIS Posting. The amount is the sum of four entries, posted 11/3/2022, 11/14/2022, 12/14/2022, and 12/15/2022. The entries and total overall are immaterial, and additional testing was not conducted.

Tariff Test

Docket DE 22-035, Liberty's request for a Third Step Adjustment, for rates effective August 1, 2022, was approved, based on capital investments made in 2021 (exclusive of growth related projects at Tuscan Village South, investment at Golden Rock Feeder 19L2, and LED Street Light Conversion); a rate decrease to reflect cessations of recovery of DE 19-064 rate case expenses and the recoupment of the difference between temporary and permanent rates in DE 19-064. See Order 26,661 issued July 29, 2022. A compliance filing of the revised tariff pages was submitted on 8/5/2022. A lengthy PUC and DoE review of ongoing tariff filings occurred throughout 2022 and 2023.

Order 26,780 issued March 1, 2023 in docket DE 22-035 approved a downward adjustment of $(575,083) in the Company's distribution revenue requirement, and Order 26,781 issued March 3, 2023 approved Liberty's proposed credit to distribution rates associated with investments placed in service in 2021 with said refund to be reflected as a credit to distribution rates from March 1, 2023 through July 31, 2023.

Order 26,836, also in docket DE 22-035, issued 5/31/2023 approved an increase to distribution rates resulting from an error uncovered by the Company and brought to the attention of the PUC. A technical statement from the Company was filed on 4/6/2023 demonstrating an incorrect method was used to reduce the revenue requirement relating to the cessation of collection of the rate case expense portion approved in Order 26,661. (See Exhibit 9 in DE 22-035.) As a result of the error, the revenues during the test year were understated by a revenue requirement amount of $1,294,385. The Order explicitly noted that the amount was to be recovered over the course of one year, terminating May 31, 2024, while acknowledging the current DE 23-039 rate case.

As a result of the various tariff filings, Audit requested and was provided with the tariffs in place during the test year.

1. Effective January 1, 2022, the Eighth Revised Page 126 and Ninth Revised Page 127 were authorized in docket DE 20-092 by Order 26,553 issued November 12, 2021.

2. The Summary of Rates, Ninth Revised Page 126 and Tenth Revised Page 127 were authorized in docket DE 21-087, Order 26,559 issued on December 27, 2021 effective February 1, 2022.

3. The Tenth Revised Page 126 and Eleventh Revised Page 127, effective March 1, 2022, were approved in docket DE 20-092 by Order 26,579 issued February 10, 2022.

4. The Eleventh Revised Page 126 and Twelfth Revised Page 127, effective May 1, 2022, were approved in dockets DE 22-018, DE 22-014, and DE 20-092 by Orders (respectively) 26,619 and 26,620 issued April 28, 2022 and Order 26,621 issued April 29, 2022.

5. The Twelfth Revised Page 126 and Thirteenth Revised Page 127 were approved by Order 26,643 in docket DE 22-024, issued June 20, 2022 with rates effective August 1, 2022.

6. The Thirteenth Revised Page 126 and Fourteenth Revised Page 127 were approved by Order 26,651 in docket DE 22-035, issued July 29, 2022 with rates effective August 1, 2022.

7. Lastly, changes to rates effective November 1, 2022 were noted on the Fifteenth Revised Page 127, the Second Revised Page 128 (Rate EV-L, Commercial Plug in Electric Vehicle Charging Station), and the Second Revised Page 133 (Rate EV-M, Commercial Plug in Electric Vehicle Charging Station). The revision to page 127 was approved by Order 26,376 in docket DE 19-064, issued June 30, 2020 and Order 26,604 in docket DE 20-170 issued April 7, 2022. The EV tariff pages were approved by Order 26,604.

However, the identification of the calculation error described above occurred after the test year. As a result, the tariff in place through 2022, while based on assumptions that were calculated incorrectly, were the approved rates in place. Audit randomly sampled a selection of year-end invoices, using the aged accounts receivable listing. The Residential rate class D was verified to the 13th revised page 126, for effect August 1, 2022. The rates for rate class D did not change thereafter. Rates for the G1-TOU customers were verified to the 14th revised page 127 and the 15th revised page 127. The M/LED-1/LED-2 rates were verified to the 15th revised page 127. Rates for the G2 customers were verified to the 13th revised page 126.

	D	G1 TOU Sep - Oct	G1 TOU Oct - Nov	G1 TOU Nov - Dec	M/LED-1/LED-2	G2-General Long Hour
Customer Charge	$ 14.74	$ 435.18	$ 435.18	$ 435.18	$ -	$ 72.52
Distribution Charge	$ 0.05857	n/a	n/a	n/a	0.04064	0.00234
Distribution Charge-Off peak	n/a	$ 0.00175	$ 0.00175	$ 0.00175	n/a	n/a
Distribution Charge-On peak	n/a	$ 0.00591	$ 0.00591	$ 0.00591	n/a	n/a
Stranded Cost Charge	$ (0.00051)	$ (0.00051)	$ (0.00051)	$ (0.00051)	$ (0.00052)	$ (0.00051)
System Benefits Charge	$ 0.00792	$ 0.00792	$ 0.00792	$ 0.00792	$ 0.00792	$ 0.00792
Transmission Charge	$ 0.03635	$ 0.02492	$ 0.02492	$ 0.02492	$ 0.01928	$ 0.02529
Energy Service Charge	$ 0.22228	n/a	n/a	n/a	$ 0.22228	$ 0.19864
Energy Service Charge-Off peak	n/a	$ 0.15134	$ 0.15134	$ 0.19864	n/a	n/a
Energy Service Charge-Off peak	n/a	n/a	n/a	$ 0.34354	n/a	n/a
Energy Service Charge-On peak	n/a	n/a	n/a	$ 0.19864	n/a	n/a
Energy Service Charge-On peak	n/a	$ 0.15134	$ 0.19864	$ 0.34354	n/a	$ 0.34354
Demand Charge	n/a	$ 9.22000	$ 9.22000	$ 9.22000	n/a	$ 9.27000
Miscellaneous Charge or Credit	various	various	various	various	various	various
High Voltage Metering	n/a	1%	1%	1%	n/a	n/a
High Voltage Delivery Credit	n/a	calculated	calculated	calculated	n/a	n/a

Audit verified December billings for customers in rate classes above. One of the G1 customers received an invoice that covered the periods 9/20/2022 through 10/19/2022, 10/20/2022 through 11/17/2022, and 11/18/2022 through 12/16/2022. It is unclear why this customer was invoiced for three months, although the Department of Energy Consumer Services division was informed by Liberty that at conversion to SAP, a significant number of both electric and gas customers had not received invoices. A quantification of the impact was requested through multiple meetings with the Company as well as through data requests in this docket, but specific quantification of customers and related revenues cannot be determined.

Overall, the tariff test determined each invoice reflected the appropriate charges for: Customer Charge, Distribution Charge, Distribution Charge-Off peak, Distribution Charge-On peak, Stranded Cost Charge, System Benefits Charge, Transmission Charge, Energy Service Charge, Energy Service Charge-Off peak, Energy Service Charge-On peak, Demand Charge, High Voltage Metering, calculated High Voltage Delivery Credit, customer reconnection fee, and a credit figure resulting from a group net metering host.

Unapplied Payments

Audit requested specific clarification regarding all unapplied payments as of the end of the test year. Monthly journal entries posted to Great Plains account 8830-2-0000-20-2111-2420 through September 2022, summing to $(854,868.49). Audit verified that that activity was rolled into SAP account 20003510242000. At year-end, the summary general ledger reflected a total of $(21,728.60). Audit was unable to verify the reported year-end figure to the detailed SAP activity, which at year-end, reflected a total of $(814,327.46. Audit communicated with Liberty several times attempting to understand what seemed to be a disconnect between the summary ledger and the detail, however, was inconclusive. The Unapplied Payments account was one of forty two #242 Miscellaneous Current and Accrued Liability accounts, that sum to $(35,849,681.42). FERC Form 1 shows a total for account 242 as $(32,120,029), a difference of $3,729,652. See A**udit Issue #1**

The difference between the SAP general ledger and the FERC Form 1 for all of account **242** was clarified by the Company to be accounts mapped incorrectly:

80111210408000 OH Payroll Tax	$ 4,620.26	exclude from #408, add to 242
24672010593000 Curr REC Obl Non-reg	$3,675,811.00	exclude from #593, add to 242
80117010921000 OH A&G n-Labor	$ 12,444.13	exclude from #921, add to 242
80111410924000 OH Property Insurance	$ 5,337.34	exclude from #924, add to 242
80111810925000 OH Injuries and Damages	$ 8,263.31	exclude from #925, add to 242
80111010926000 OH Benefits	$ 17,353.50	exclude from #926, add to 242
80111310926000 OH Pension/OPEB	$ 5,823.05	exclude from #926, add to 242
	$3,729,652.59	**Audit Issue #1**

Also noted on RR-2.2 was a flowthrough of $1,018,212 for the Provision for Refunds account 449, which Audit verified to the general ledger 40033010449100.

Liberty provided the monthly general ledger and Cogsdale then SAP revenue reconciliations, which were reviewed by Audit.

During the audit work related to DE 19-064, Audit questioned the reflection on the FERC Form 1 of the Forfeited Discounts 450 as Miscellaneous Service Revenues and another figure as Forfeited Discounts. In response, the Company provided details of how the GL data for both accounts was calculated because the figures were within the same general ledger account. The reflection within the 2022 FERC Form 1 correctly reflected Miscellaneous Service Revenue on the line for account 450 only.

Accrued Utility/Unbilled Revenue

Audit reviewed the general ledger activity and noted that the monthly unbilled credits auto-reverse on the first of the following month.

Audit requested the unbilled revenue calculations for December 2021, January 2022, December 2022 and January 2023, to review for significant changes between December year-end calculations and January monthly calculations:

12/2021 Unbilled Revenue Recognition		Debit	Credit	01/2022	
88302-0000-10-1162	Accrued Utility Revenue	$ 2,248,595.81		$ 2,356,516.99	
8830-2-0000-40-429	Residential Sales-Fixed		$ (257,027.47)		$ (258,840.44)
8830-2-0000-40-429	Residential Sales-Variable		$ (914,155.55)		$ (1,032,591.29)
8830-2-0000-40-429	Commercial Sales-Fixed		$ (100,387.08)		$ (98,972.94)
8830-2-0000-40-429	Commercial Sales-Variable		$ (757,378.48)		$ (765,112.26)
8830-2-0000-40-429	Industrial Sales-Fixed		$ (9,717.63)		$ (9,341.75)
8830-2-0000-40-429	Industrial sales-Variable		$ (177,476.99)		$ (156,383.29)
8830-2-0000-40-429	Street Lighting Fixed		$ (32,452.61)		$ (35,275.03)
		$ 2,248,595.81	$ (2,248,595.81)	$ 2,356,516.99	$ (2,356,517.00)

12/2021 Unbilled Commodity Cost					
8830-2-0000-10-110	A/R Under Collected	$ 2,139,308.62		$ 2,424,919.50	
8830-2-0000-40-429	Provision for Rate Refunds		$ (2,139,308.62)		$ (2,424,919.50)
		$ 2,139,308.62	$ (2,139,308.62)	$ 2,424,919.50	$ (2,424,919.50)

12/2022 Unbilled Revenue Recognition		Debit	Credit	01/2023	
110100-10173000	Accrued Utility Revenue	$ 2,818,874.71		$ 2,729,645.00	
400010-10440000	Residential Sales-Fixed		$ (312,834.54)		$ (310,662.59)
400100-10440000	Residential Sales-Variable		$ (977,677.21)		$ (1,107,475.31)
400020-10442000	Commercial Sales-Fixed		$ (126,857.10)		$ (130,944.24)
400110-10442000	Commercial Sales-Variable		$ (1,277,916.44)		$ (1,072,981.84)
400050-10442000	Industrial Sales-Fixed		$ (3,513.17)		$ (3,511.17)
400120-10442000	Industrial sales-Variable		$ (74,034.12)		$ (66,679.17)
400060-10444000	Street Lighting Fixed		$ (38,244.70)		$ (31,193.57)
400130-10444000	Street Lighting-Variable		$ (7,797.43)		$ (6,197.11)
		$ 2,818,874.71	$ (2,818,874.71)	$ 2,729,645.00	$ (2,729,645.00)

12/2022 Unbilled Commodity Cost					
130800-10142000	A/R Under Collected	$ 4,586,344.00		$ 4,541,895.24	
400330-10449100	Provision for Rate Refunds		$ (4,586,344.00)		$ (4,541,894.24)
		$ 4,586,344.00	$ (4,586,344.00)	$ 4,541,895.24	$ (4,541,894.24)

Supporting calculations were provided for each month. However, the details relating to the Base Energy Service Rate portion were redacted within the 12/2021 and 1/2022 unbilled calculation details, and simply eliminated in the 12/2022 and 1/2023 calculations. Audit requested the complete unredacted versions of the calculation, and was provided with the confidential pages in the DE 21-087 Energy Service Reconciliation Schedule HMT/AMH-1 Rates Page 1 of 1 and HMT/AMH-2 Rates Page 1 of 1, and DE 22-024 Attachment HMT/AMH-1 Page 1 of 1 and Attachment HMT/AMH-2, Page 1 of 1, rather

Payroll

During test year 2022, all GSE employees were employed by Liberty Utilities Service Corp.

Payroll is completed on a weekly and bi-weekly basis. Union employees, such as linemen, are paid on a weekly basis whereas non-union employees are paid bi-weekly.

The final 2022 pay period for weekly paid employees ended December 24, 2022 and was paid December 30, 2022. The final pay period for bi-weekly paid employees ended December 17, 2022 and paid December 23, 2022. Audit reviewed both detailed payroll registers for the final pay periods.

Audit requested the payroll journal entry for Liberty NH, 3070, final weekly and bi-weekly pay period of the year. GSE provided the payroll journal entry signoff, for both weekly and bi-weekly, which shows information such as the account and amount.

Audit additionally requested the journal entry booking the payroll from 3070 to GSE 3071 and ENG 3072. Liberty noted "*this is no longer done as a manual journal entry hence there is no actual document, instead it is an automated process in SAP. The payroll team received a "Success Report" from SAP when the entry goes through"*. Liberty provided am example of the "Success Report" which states "Document Posted Successfully:" with a numerical and alphabetical code.

Audit requested an explanation as to how the payroll is reconciled to the general ledger now that a previously used report is no longer available in SAP. Liberty's response was as follows:

"The process used to reconcile payroll is first to run a Timesheet report to gather all labor hours entered for a particular month. Then the total amount of labor per weekly/bi-weekly timesheet is compared to the Payroll Register report dollar amounts. Minor variances are expected due to the timing of transactions posting in the Timesheet system (WFS) vs Payroll Processing System (SAP)."

Liberty provided the reconciliation for the payroll paid in the month of December 2022. The timesheet report shows a total of $1,096,705 for bi-weekly while the payroll register shows $1,086,078, resulting in a variance of $10,627. For weekly payroll, the timesheet report shows $2,178,999 and the payroll register shows $2,180,340, resulting in a variance of ($1,341.04). Audit notes that the reconciliation provided did not include any general ledger detail as requested. Audit is unable to determine if the general ledger accurately reflects the payroll expense for 2022. **Audit Issue #13**

Payroll Test

Audit requested and received a listing of all Liberty employees in which a portion of their full payroll expense is charged to GSE. Audit randomly selected and seven weekly employees and eight bi-weekly employees for a review of timesheets, paystubs and W2s.

Bi-weekly timesheets for the period of December 4, 2022 through December 17, 2022 were reviewed in detail. Audit was able to tie seven of the eight bi-weekly paid employees' timesheets to the payroll register detail and W2s. The final timesheet reviewed was a four factor allocation and was therefore not on the payroll register. Four factor allocation is further discussed on page 4 of the report. Types of pay included regular hours, vacation pay, and jury duty pay.

Audit noted that when rest time is noted on the actual timesheet, it is when banked rest hours are being used. If the rest hours are earned during the pay period, it will show in the result tab of the payroll system as it is entered by the supervisors not the actual employee. Audit verified the rest hours that were paid and earned during the pay period were done without exception.

Audit reviewed the seven weekly paid employees' timesheets for the period of December 18, 2022 through December 24, 2022 in detail. Six of the electric employee's hourly rate, based on job title, was verified to the Union Contract without exception. The seventh employee's pay rate was higher than the hourly rate noted for their job title in the union handbook. Further review of the employee's timesheet noted they were acting in the roll of "troubleshooter" and was therefore paid the troubleshooter hourly rate. No exception was noted.

The types of pay employees received during the final pay period included regular, overtime, call back, storm duty, mutual aid storm duty and others.

All hours recorded on eight weekly employees' timesheets were verified to the payroll register detail without exception. All premium rates, such as overtime, storm duty and mutual aid, paid to the employees were verified to the union contract without issue. The premium rate paid for storm duty versus mutual aid storm duty is at different rates. Audit questioned how the rates are differentiated on the timesheet and it was noted that the WBS element - job code will be different for storm duty and mutual aid storm duty.

Schedule RR-3.4 in the filing stated the total O&M payroll for 2022 was $5,038,152 as shown below:

FERC Account	2022 Test Year Salaries and Wages OCOA/500000	2022 Test Year Vacation & Other TO OCOA/500100
563	148	-
580	995,037	6,173
581	129,067	2,331
582	137,514	-
583	705,708	3,649
584	(272)	-
585	30,738	-
586	302,977	(12,832)
587	45,670	-
588	290,215	3,589
590	13,469	175
591	105,704	41
592	131,559	-
593	568,816	7,374
594	22,178	-
595	3,701	-
596	27,115	31
597	26,823	-
598	29,806	-
901	36,259	-
902	260,785	-
903	503,920	(399)
905	16,000	-
909	24,257	-
912	12,609	3,370
916	167,170	-
920	725,045	(135,238)
922	(283,886)	-
923	8,440	-
935	1,579	-
Total in Test Year	**5,038,152**	**(121,737)**
Total Salaries and Wages in Test Year	**4,916,416**	

GSE provided a trial balance for the payroll, which summed to $6,071,380. The trial balance provided showed the total labor per month per FERC account. Of the thirty FERC accounts noted in the Schedule RR-3.4, nine of them did not tie to the payroll trial balance provided by GSE.

Audit compared the trial balance totals to the detailed general ledgers. For the months of January through September, while GP was in use, the O&M payroll trial balance matched the detailed general ledger.

During this comparison of the trial balance to the GL, Audit determined that the payroll trial balance for October through December, in SAP, included other labor expenses and not just salaries and wages. Audit reviewed the detail SAP GL and calculated only the salaries and wages to tie to Schedule RR-3.4.

No exception was noted with the comparison of Schedule RR-3.4 and the 2022 detail general ledger.

Audit notes that filing Schedule RR-2.1 shows total O&M payroll as $5,682,718. This figure includes Salaries & Wages, Vacation & Other TO and overtime paid. The $4,916,416 test year total in Schedule RR-3.4 only includes Salaries & Wages and Vacation & Other TO.

The Dayforce Payroll Register Reports, weekly and bi-weekly combined, shows a total payroll of $36,182,458 for the year. The payroll register reflects all payroll for NH, which includes GSE and ENG. Due to this, Audit was not able to directly tie the Schedule RR-3.4 to the Dayforce report. GSE previously noted during the rate case audit in Docket DE16-383 that the Dayforce report will not tie directly to Schedule RR-3.4 as Dayforce is only NH employees where Schedule RR-3.4 represents all payroll charged to NH.

GSE's payroll is processed through Ceridian. Audit reviewed the Ceridian contract in detail, which noted the contract terms and fees charged.

Union contracts and Payroll Policies and Procedures that were in place during the test year were obtained and reviewed.

Liberty Utilities and Algonquin Payroll

Audit requested and received the November 2022 direct and indirect LUC, LUSC, and LABS billings. Audit reviewed the detail in the billings for payroll and payroll taxes. Please refer to the *Allocation* section of this report for a detailed review.

Temporary Employees

Audit requested the total paid to temp agencies and to which general ledger the expenses were booked. In response, GSE provided documentation that totaled $456,528.50 paid to Balance Professionals. The response also noted the *"expenses were charged to GL account 500300"*, which is noted to be Outside Services.

Audit reviewed the Excel document sent in response to the request and attempted to verify it to the detail general ledger. Audit began with the GP detail for January through September which showed a total of $404,502 in expenses for Balance Professional. The response provided showed the vendor name, document date, document number, and document amounts. Additional information was also provided but no general ledger account was included. Audit attempted to verify the response to the GL based on the document date, document number and/or amount as noted in the response. Audit notes that the GP GL shows a total of $111,032.77 being expensed to GSE for Balance Professionals to the following accounts:

8830-2-0000-10-1618-1070	$	81,815.40
8830-2-0000-10-1655-1084	$	320.32
8830-2-9800-69-5200-9230	$	436.80
8830-2-9815-69-5200-9230	$	56.03
8830-2-9820-69-5130-9210	$	8,419.32
8830-2-9820-69-5200-9230	$	6,639.36
8830-2-9825-51-5435-5880	$	733.92
8830-2-9825-69-5130-9210	$	8,151.66
8830-2-9825-69-5200-9230	$	4,133.98
8830-2-9851-51-5430-5870	$	219.64
8830-2-9851-51-5435-5800	$	106.34
	$	111,032.77

Audit then attempted to verify the SAP October through December audit response to the detail general ledger. The audit request shows a total of $52,027 being booked to the general ledger for Balance Professional during the last three months of the year. The detail GL shows $30,393 as being booked to SAP account 50030010920000 in 2022.

Audit was unable to verify any of the information provided to the detail GP and SAP general ledger. **Audit Issue #14**

<u>End of Year Accruals</u>

Audit received the payroll accruals booked for weekly and bi-weekly payroll for the days worked in December 2022 but not paid until January 2023. As the final pay in 2022 for bi-weekly employees was for the period ending 12/17/22, the payroll accrual was for the period of 12/18/22 through 12/31/22. The final pay period for weekly employees ended 12/24/23, therefore accruals were for the period of 12/25/23 through 12/31/23.

Audit requested supporting documentation for the end of year payroll and vacation accruals. The documentation provided, shows it is for company code 3070, Liberty NH. Audit requested supporting documentation for the accrual calculations and only received the journal entries booking the accrual. Due to not receiving the payroll support, Audit was unable to verify the payroll accruals to the GSE general ledger. **Audit Issue #15**

<u>Employee Benefits</u>

Audit requested a listing of all payments made for employee benefits such as health, dental, retirement and others for the month of December. GSE provided a listing of all group benefits journal entries. Because all employees are employed by Liberty Utilities Service Group, the full amount of the benefits is expensed to company 8810/3070. A 30/70 allocation is done and 30% of the charges are allocated to 8830/3071.

Audit reviewed the Liberty Utilities, 3070, general ledger employee benefits entries from December 2022. Audit recalculated 30% of each entry and tied the amount to the following GSE general ledger account entries:

FERC Account	SAP GL Code	Natural Account	NAME	Amount
926	0L_3071_10167_1016725100_500170_10926000	500170	Group Benefits	119,079.55
408	0L_3071_10167_1016725100_500120_10408000	500120	Federal Unemployment taxes/Tx Oth Inc Tx-St Unempl Tax	142.51
926	0L_3071_10167_1016725100_500160_10926000	500160	401k Plan Expenses/Pension Plan Expenses/401K Match	99,897.10
926	0L_3071_10167_1016725100_500170_10926000	500170	Group Benefits	(159,261.80)

No exception was noted with the allocation of the employee benefits to GSE's general ledger. There was an exception with the account the Federal Unemployment taxes were booked to as noted in the *Payroll Taxes* section.

Per the IBEW union contract, pages 39 and 40, employees who do not meet a certain criteria (age plus years of service) were to be moved from the Liberty Energy Utilities Corp Retirement Plan for Union Employees to the Liberty Utilities Cash Balance Pension Plan. This was effective January 1, 2016. Employees who are under the age of 55 as of December 31, 2015 and were moved to the new pension plan were to have the Company make annual deposits to their 401K plan at the end of each calendar year for a total of 10 years. For employees who were over 55 and converted, the Company is to make annual deposits until the employee reached the age of 65.

Per the USW (United Steel Workers) union contract, pages 48 and 49, employees who do not meet that same criteria are also being moved from the Retirement Plan to the Pension Plan effective January 1, 2017. Annual deposits for the USW employees were to begin at the end of 2017.

Audit requested, from the Company, the total paid in transition deposits for 2022. Liberty noted that $38,183 was booked for IBEW and $194,891.10 was booked for USW to SAP account 500160. Audit reviewed the SAP GL detail for account 50016010926000 and was unable to verify the payment amounts.

Additional information was provided to Audit noting that the previously provided transition total of $233,074.10 was the NH total and not GSE. Support showed the $233,074.10 amount being allocated 70/30 with $99,987.10 being booked to GSE. Audit recalculated the amount without exception.

Audit verified the amount booked to the GSE (3071) GL to the following accounts on 12/31/2022:

Debit 50016010926000	$99,987.10	
Credit 11101010146000		$99,987.10

<u>Retirement Plan</u>

Audit requested a listing of payments that were made in 2022 to fund the retirement plan. GSE provided a summary of pension contributions, which shows by quarter, contribution amount for Pension Plan and Defined Benefit Pension Plan. The summary shows the GSE Pension contribution for Quarter One being $197,750 and the Quarter Two – Quarter Four contributions were $200,670 each. The total Pension contributions for the year were $799,760.

The summary of Defined Benefit Pension Plan contributions shows quarterly amounts for GSE as $100,000 for the first quarter and $99,000 for the second through fourth quarters totaling $397,000.

Audit reviewed in detail the general ledger account 8830-2-0000-20-2930-2285, Long Term Pension Obligations. Audit was able to verify the Quarter One, Quarter Two and Quarter Three, Pension Plan and Defined Pension Plan, contributions to the GP GL without exception. Audit verified the Fourth Quarter contribution booked to SAP account 28003010228300 without exception.

The quarterly contribution amounts were booked to the general ledger, for both the Pension Plan and Defined Benefit Pension Plan on the following dates; 4/12/2022; 7/12/2022; 7/14/2022 and 12/16/2022. On 10/31/2022 the amounts of $200,670 and $99,000 were credited to the account. The journal entry did not note the reason for the credit.

<u>Incentive Plan</u>

In the filing requirements, beginning on Bates page I-139, are the details of all officer and executive incentive plans. Additional incentive plan information was provided in response to DOE Data Request 4-25. Included in this information was the costs of each incentive program for 2022.

A total of $600,09.85 was expensed in 2022 for short term incentive bonuses. The data request response noted it was booked to FERC account 920. Audit verified the total for the year to SAP general ledger account 50022010920000 without exception.

A total of $48,550.53 was booked to FERC account 920 for the long term incentive plan. Audit was able to verify that amount to the detail SAP GL account 50021010920000 without exception.

The data request response also noted that $20,423.82 was booked to FERC 926 for employee stock purchase plan (ESPP). The response also notes that *"in preparing this response, the Company identified that $5,472.44 ($18,241.46 * 30%) of the ESPP was not allocated from LUNH (Company 3070) to Granite State Electric (Company 3071) in the test year. The Company will correct that amount in its next cost of service update in this proceeding."*

Audit was able to verify the $20,423.82 for ESPP to the general ledger detail without exception.

Severance Pay

Liberty provided a response to Department of Energy Data Request 4-38 noting $118,806.65 was paid for severance during 2022. The response to DOE 4-38 also noted that $36,424.81 was paid in 2021 and $15,775.91 paid in 2020 for severance. The amount of severance paid in 2022 was 226% higher than 2021 and 653 % higher than 2020.

Audit requested documentation showing the GL accounts to which the $118,806.65 in severance was booked. In GSE's response to the audit provided the following breakdown of the severance paid:

Pay Date	Year	GL Account	Amount
10/28/2022	2022	3070-500000-1016625300	$ 4,657.46
11/10/2022	2022	3070-500000-1016625300	$ 4,657.46
11/25/2022	2022	3070-500000-1016625300	$ 4,657.46
12/9/2022	2022	3070-500000-1016625300	$ 4,657.46
12/23/2022	2022	3070-500000-1016625300	$ 4,657.46
1/9/2023	2022	3070-500000-1016625300	$ 4,657.46
			$ 27,944.76
5/13/2022	2022	3060-500000-1014910100	**$ 83,278.84**
12/23/2022	2022	3070-500000-1016648100	**$ 7,583.04**
Total			**$ 118,806.64**

Audit was unable to verify the amounts to the GL detail as the severance is paid through payroll and not as a separate line item.

The bi-weekly payroll register for 2022 shows a total of $7,583.04 being paid through the NH payroll. The weekly payroll register does not show any severance being paid in 2022 to NH employees.

Payroll Taxes

The payroll taxes, as stated on Filing Schedule RR-2.11, were verified to the general ledger and FERC Form 1, account 408.

Great Plains Accounts		SAP Accounts		Year End Balance
8830-2-9810-69-5040-4080	Social Security Taxes	50011010408000	SS/CPP/Emp Pension	$ 457,572.75
8830-2-9810-69-5041-4080	Federal Unemployment Taxes	50012010408000	Unemp/Emp Insurance	$ 4,266.97
8830-2-9810-69-5041-4082	State Umemployment Taxes	50012010408200	Unemp/Emp Insurance	$ 26,441.45
8830-2-9810-69-5042-4080	Medicare	50015010408000	Medicare/Healthcare	$ 125,785.88
		50013010408000	FICA Taxes	$ 236.79
		85311210408000	As Prl Tx-Intrc	$ 28,631.62
				$ 642,935.46

Audit reviewed the payroll tax general ledger detail in both GP and SAP. Audit notes that there was no activity in the SAP Social Security Tax, Federal Unemployment Tax, State Unemployment Tax, and Medicare general ledger accounts in October, November or December 2022. Audit was unable to verify any of the payroll tax general ledger accounts to supporting documentation received during the audit process.

Audit requested clarification was to what the new SAP account 85311210408000 with an ending balance of $28,631.62 was used for. GSE responded with the following:

"As Prl Tx-Intrc, account 853112-10408000, records the settlement of the assess payroll tax component of overhead costs associated with *intercompany* (underlined for emphasis) *labor costs recorded to 10408000. There were no costs recorded prior to October due to following a different overhead process in GP in which overhead costs were recorded in total, not by component, and charged directly to the respective GL account."*

The SAP general ledger included a FERC 408 account that was not included on filing Schedule RR-2.11. This was account number 80111210408000, OH Payroll Tax, totaling $4,620.26. Audit also requested additional information on the use of this account and received the following from GSE:

"OH Payroll Tax, account 801112-10408000, records the settlement of the payroll tax component of overhead costs associated with labor costs recorded to 10408000. There were no costs recorded prior to October due to following a different overhead process in GP in which overhead costs were recorded in total, not by component, and charged directly to the respective GL account."

For the months of January through September, for each pay period the payroll taxes and benefits are booked to 8810 and cleared at the end of the month. The monthly 8810 tax amounts were then allocated to 8830 and 8840 using the 70/30 split. Following the conversion to SAP, the taxes and benefits are booked to Company 3070 and allocated to 3071 and 3072 using the 70/30 split.

Following the conversion to SAP, no tax entries were booked for the months of October, November and December to the 408 accounts. Audit requested a copy of the payroll tax clearing journal entry for December 31, 2022. There was only one amount, $142.51, for payroll taxes. Audit recalculated the payroll tax amount to be 30% of the amount booked to 3070 without exception. The journal entry shows the unemployment taxes were booked to FERC account 920. **Audit Issue #16**

Audit requested a payroll tax account reconciliation for the year of 2022. GSE provided an Excel spreadsheet showing the total State Unemployment, Federal Unemployment, Social Security and Medicare taxes. The Excel spreadsheet detailed the tax amount per pay period for both weekly and bi-weekly pay. GSE noted in their response to the request that the tax detail provided was for all LUSC employees and not specific to NH. Due to this, Audit was unable to tie the payroll tax amounts from the reconciliation back to the NH year end payroll registers.

Audit was able to tie the detail for all LUSC employees to their tax filing Form 940, Employer's Annual Federal Unemployment (FUTA) Tax Return, and to the New Hampshire Unemployment Summary of Deposits and Filings. Audit was unable to verify the Form 941, Employer's Quarterly Federal Tax Return to the payroll tax reconciliation provided of Social Security and Medicare expenses.

Operations and Maintenance Expenses $111,435,705

Great Plains general ledger software Account string information, reflects:

Company GSE	US Dollar	Site/Dept	Class	Natural Account	Sub-account
8830-	2-	XXXX-	XX-	XXXX-	XXXX

The first three digits of the final sub-account represent the FERC Uniform System of Accounts account number. Effective October 1, 2022, the Company converted from Great Plains to the SAP software system. The account string information relating to that new system (generally) is:

3071 is Granite State Electric

XXXXXX 6 Digit number is the corporate general ledger account number

XXXX 4 digit code is the regulatory identification number

XXXXXXXXXXXXX is a combination of the 6 digit corporate general ledger account number and the four digit regulatory identification, with 3 place holders for subaccounts.

The reported Operations and Maintenance expense total on the filing schedule RR 2.1 was $110,587,557. The FERC Form 1 was $111,435,705 and the 12/31/2022 SAP was $110,727,635 indicating the following variances:

Filing Schedule 2.1	FERC Form 1	SAP General Ledger as of 12/31/2022	VARIANCES Schedule 2.1 vs. FERC Form 1	VARIANCES FERC Form 1 vs. SAP GL as of 12/31/22
$ 110,587,557.00	$111,435,705.00	$ 110,727,635.00	**$848,148.00**	**$ 708,070.00**

The variances are addressed throughout this report in various Audit issues. For the test year, overall operations and maintenance expenses **increased by 49%** over the 2021 ending balances.

Below is the roll-forward of the Operations and Maintenance Expense accounts per the FERC Form 1, since the prior 2018 test year: Refer to **Audit Issue #1**

		12/31/2019	12/31/2020	12/31/2021	12/31/2022	% change 22 vs. 21
555	Purchased Power	$ 40,022,127	$ 32,977,041	$ 32,423,121	$ 72,139,166	122%
	Total Power Production Expense	$ 40,022,127	$ 32,977,041	$ 32,423,121	$ 72,139,166	122%
561.4	Scheduling, System Control and Dispatch Services	$ 533,940	$ 561,142	$ 617,507	$ 427,346	-31%
563	Overhead Line Expenses	$ 1,316	$ 3,012	$ 2,388	$ 4,498	88%
565	Transmission of Electricity by Others	$ 21,586,953	$ 24,841,129	$ 26,260,820	$ 19,502,455	-26%
570	Maintenance of Station Equipment	$ -	$ -	$ -	$ -	#DIV/0!
	Total Transmission Expenses	$ 22,122,209	$ 25,405,283	$ 26,880,715	$ 19,934,299	-26%
580	Operation Supervision and Engineering	$ 1,342,483	$ 1,427,462	$ 1,503,612	$ 1,224,031	-19%
581	Load Dispatching	$ 280,622	$ 247,677	$ 180,680	$ 126,630	-30%
582	Station Expenses	$ 141,228	$ 181,075	$ 264,595	$ 152,948	-42%
583	Overhead Line Expenses	$ 744,316	$ 588,943	$ 894,444	$ 1,170,626	31%
584	Underground Line Expenses	$ 56,320	$ 1,255	$ 3,397	$ 14,326	322%
585	Street Lighting and Signal System Expenses	$ 14,761	$ 28,326	$ 26,248	$ 39,132	49%
586	Meter Expenses	$ (73,724)	$ 7,337	$ 193,471	$ 315,949	63%
587	Customer Installation Expenses	$ 70,898	$ 58,172	$ 54,261	$ 48,988	-10%
588	Miscellaneous Expenses	$ 1,309,496	$ 1,063,451	$ 1,233,172	$ 1,613,700	31%
	Total Distribution Operation Expenses	$ 3,886,400	$ 3,603,698	$ 4,353,880	$ 4,706,330	8%
590	Maintenance Supervision and Engineering	$ 19,071	$ 16,490	$ 14,742	$ 13,943	-5%
591	Maintenance of Structures	$ 128,959	$ 107,071	$ 137,304	$ 129,865	-5%
592	Maintenance of Station Equipment	$ 117,218	$ 217,753	$ 298,547	$ 238,334	-20%
593	Maintenance of Overhead Lines	$ 3,023,162	$ 2,948,878	$ 4,619,392	$ 5,452,702	18%
594	Maintenance of Underground Lines	$ 44,932	$ 26,023	$ 21,887	$ 167,310	664%
595	Maintenance of Line Transformers	$ 16,596	$ 54,153	$ 38,087	$ 3,701	-90%
596	Maintenance of Street Lighting and Signal Systems	$ 100,966	$ 67,293	$ 42,695	$ 39,278	-8%
597	Maintenance of Meters	$ 62,838	$ 58,366	$ 45,165	$ 53,762	19%
598	Maintenance of Miscellaneous Distribution Plant	$ 59,960	$ 84,450	$ 47,590	$ 59,472	25%
	Total Distribution Maintenance Expenses	$ 3,573,702	$ 3,580,477	$ 5,265,409	$ 6,158,367	17%
	Total Distribution Expenses	$ 7,460,102	$ 7,184,175	$ 9,619,289	$ 10,864,697	13%
901	Supervision	$ 105,818	$ 59,119	$ 48,490	$ 45,592	-6%
902	Meter Reading Expenses	$ 356,325	$ 326,375	$ 345,953	$ 353,272	2%
903	Customer Records and Collection Expenses	$ 1,322,332	$ 1,067,091	$ 1,129,379	$ 1,049,339	-7%
904	Uncollectible Accounts	$ 152,841	$ 233,314	$ 281,647	$ 272,932	-3%
905	Miscellaneous Customer Accounts Expenses	$ 29,592	$ 36,479	$ 29,720	$ 20,000	-33%
	Total Customer Accounts Expenses	$ 1,966,908	$ 1,722,378	$ 1,835,189	$ 1,741,135	-5%
907	Supervision	$ -	$ -	$ -	$ -	#DIV/0!
909	Informational and Instructional Expenses	$ 50,723	$ 100,090	$ 72,065	$ 97,960	36%
910	Misc. Customer Service and Informational Expenses	$ 6,956	$ -	$ 1,482	$ -	-100%
	Total Customer Service and Informational Expenses	$ 57,679	$ 100,090	$ 73,547	$ 97,960	33%
912	Demonstrating and Selling Expenses	$ 10	$ -	$ 150	$ (10,827)	-7318%
913	Advertising Expense	$ 206	$ -	$ 252	$ -	-100%
916	Miscellaneous Sales Expenses	$ 171,261	$ 192,485	$ 208,419	$ 170,411	-18%
	Total Sales Expenses	$ 171,477	$ 192,485	$ 208,821	$ 159,584	-24%
920	Administrative and General Salaries	$ 2,759,425	$ 2,906,055	$ 2,883,082	$ 2,877,428	0%
921	Office Supplies and Expenses	$ 922,168	$ 1,226,518	$ 1,425,717	$ 2,287,231	60%
922	Administrative Expenses Transferred-Credit	$ (10,430,407)	$ (10,563,333)	$ (11,574,397)	$ (8,002,460)	-31%
923	Outside Services Employes	$ 3,374,761	$ 3,410,426	$ 3,048,900	$ 2,381,415	-22%
924	Property Insurance	$ 1,550,463	$ 1,500,862	$ 1,572,228	$ 1,589,317	1%
925	Injuries and Damages	$ 554,459	$ 589,428	$ 800,546	$ 927,599	16%
926	Employee Pensions and Benefits	$ 4,239,168	$ 4,251,696	$ 4,713,113	$ 3,697,502	-22%
928	Regulatory Commission Expenses	$ 521,240	$ 519,161	$ 547,366	$ 643,455	18%
930.2	Miscellaneous General Expenses	$ 2,639	$ 220,171	$ 61,330	$ (115,412)	-288%
931	Rents	$ 154,099	$ 168,379	$ 192,391	$ 205,469	7%
	Total Administrative and General Operation Expenses	$ 3,648,015	$ 4,229,363	$ 3,670,276	$ 6,491,544	77%
935	Maintenance of General Plant	$ -	$ -	$ -	$ 7,320	#DIV/0!
	Total Administrative and General Maintenance Expenses	$ -	$ -	$ -	$ 7,320	#DIV/0!
	Total Administrative and General Expenses	$ 3,648,015	$ 4,229,363	$ 3,670,276	$ 6,498,864	77%
	TOTAL Operation and Maintenance Expenses	**$ 75,448,517**	**$ 71,810,815**	**$ 74,710,958**	**$111,435,705**	49%

<u>FERC Form 1 reflects the following relating to Power Production and Transmission expenses</u>:

555 Purchased Power	$72,139,166
561.4 Scheduling, System Control and Dispatch Services	$ 427,346
563 Overhead Line Expenses	$ 4,498
565 Transmission of Electricity by Others	<u>$19,502,455</u>
	$92,073,465

Audit notes that all 4 accounts were proformed out per revenue requirement schedule RR-2.1. Audit verified the reported **flow-through expense accounts on the filing RR-2-1** to the 2022 detailed general ledger. Specifically:

<u>Purchased Power – Account 555 $72,139,166</u>

Audit verified that the Great Plains activity from January 2022 through September 2022 was incorporated into the SAP year-end balances:

8830-2-0000-52-5455-<u>555</u>1 Purchased Power-Variable	$ -0-
8830-2-0000-52-5455-<u>555</u>2 Purchased Power-Fixed & SO	$44,453,339.60
8830-2-0000-52-5455-<u>555</u>3 PP-NEP-Access Charge-Elim	<u>$ (452,573.97</u>)
Great Plains as of 9/30/2022	$44,000,765.63

The FERC Form 1 balance of $72,139,166 was verified to the SAP general ledger year-end balance. The Great Plains activity was rolled into the following SAP accounts:

52001010555000	Elec Pur Power Misc	$ 61,368,862.82
52001010555001	Elec Pur Power Misc	$ 10,860,546.00
52001010555002	Elec Pur Power Misc	$ (90,243.14)
		$ 72,139,165.68

The overall power production expenses increased by 122% over the 2021 ending balances. Entries among the 3 accounts included CTC, Stranded Cost Revenue, monthly purchase power accruals, and ISO remittances. Because the accounts above were identified as flow through items, Audit reviewed the account activity, but did not perform further test work. The accounts and balances were verified to the filing schedule RR-2.4.

<u>Transmission Expenses – Accounts 561.4, 563 and 565</u>

The FERC Form 1 balance of $427,346 balance for account <u>561.4</u>, Scheduling, System Control and Dispatch Services was verified to both the GP account, formerly account 8830-2-0000-51-5440-5614 and SAP account 52001010561400. The net GP activity was rolled into SAP through September 30, 2022 with no other transactions past this date. Overall expenses decreased 31% from 2021 and included 9 entries for ISO-NE invoices that were all posted mid-month. Audit did not perform further test work since the account is a flow though account and was proformed out on schedule RR-2.1 and RR-2.5.

Account 563, Overhead Line Expenses in 2021 consisted of 3 GP accounts which were the following:

8830-2-0000-51-5010-5630 Overhead Lines-Labor
8830-2-0000-51-5410-5630 Overhead Lines
8830-2-9851-51-5010-5630 Overhead Lines

The GP accounts were combined into one account in 2022 in account 8830-2-9851-51-5010-5630 which had an ending balance of $148.05 as of September 30, 2022. The GP account was rolled forward into the following 4 SAP accounts with the ending balance of $4,498 verified to FERC Form 1 and to filing schedules RR-2.1 and RR-2.5

50000010563000	Salaries and Wages	$ 148.05
50030010563000	Outside Svs	$ 2,474.86
50500010563000	Other Operating Exp	$ -0-
80000010563000	Lbr Alloc	$ 1,875.20
		$ 4,498.11

The overall expense were 88% more than the 2021 and consisted of 1 payroll entry totaling $148.05 for services from 1/9/2022 to 1/15/2022 and was offset to account 8830-2-0000-20-2810-2606, Due to Liberty Energy New Hampshire. The other entries in SAP were minimal debit and credit reversals summing to $4,350.06.

The FERC Form 1 Account 565, Transmission by Others amount of $19,502,455 was verified to the SAP general ledger account 52001010565000. Audit confirmed the GP activity from January through September 2022 former GP account 8830-2-0000-51-5441-5650, was rolled for to the one SAP account. The SAP ending balance amount was consistent with the filing amount listed on schedule RR-2-1. The 2022 expenses were 26% less than 2021. Expenses consisted of monthly payments to ISO New England, Inc (ISO). and New England Power, Co. (NEP). Both the ISO and NEP charges are for local and regional transmission service. Audit reviewed the activity however no further test work was completed, as previously mentioned, the account was proformed out on schedule RR-2.1 and RR-2.5.

<u>Account #580</u>, Operation Supervision and Engineering $1,224,031was verified from the following 22 SAP accounts, included in the filing schedule RR-2.6 to the FERC Form 1:

50000010580000	Salaries and Wages	$	995,037.23
50001010580000	Overtime	$	1,716.61
50005010580000	AllocCorp Lbr Leg	$	(97,201.36)
50010010580000	Vacation & Other TO	$	6,173.16
50121010580000	Fleet-Fuel	$	(13,458.82)
50500010580000	Other Operating Exp	$	250,933.86
50501010580000	Current Exchng Fees	$	5.33
50530010580000	Clr CIAC CWIP P&L	$	-0-
80000010580000	Lbr Alloc	$	5,954.64
80300010580000	Assess Lbr	$	(28,690.43)
80302010580000	Assess Material	$	155.00
80304010580000	Assess Other	$	819.10
80305010580000	Assess Fleet - Asses	$	15.32
80308010580000	Assess Meals	$	2,411.56
80308510580000	Assess Travel	$	2,860.81
80311010580000	Assess OH Benefit	$	97.46
85300010580000	Assess Lbr-Intrc	$	90,044.96
85304010580000	Assess Other-Intrc	$	1,720.70
85305010580000	As Fleet - Intrc	$	161.57
85308010580000	Assess Meals -Intrc	$	4,616.01
85308510580000	Assess Travel-Intrc	$	2,650.70
85311010580000	As OH BenIntrc	$	(1,992.58)
		$	1,224,030.83

Audit verified the Great Plains 9/30/2022 balances in eight individual accounts to the SAP 9/30/2022 starting balance. The overall expense total for 2022 represents a 19% decrease from the 2021 expense total.

The January through September 2022 GP entries in Account, 8830-2-9854-51-5435-5800 -Operation – Engineering included monthly fleet allocation with 1 reversal and 1 recalculated fleet charge occurring in February, there was also 1 reclassification entry in April 2022. The January through September 2022 net activity in the former GP account 9854-51-5435-5800 was rolled into SAP account 50500010580000. Audit could not trace any transactions past September in this account or any other 580 account related to the monthly fleet allocations. **Audit Issue #17**

Audit also reviewed a large credit entry/job dated 9/12/22 and totaled ($16,830). The entry was offset to GP account 8830-2-0000-10-1020-1310 (Cash) and was payment from Kearsarge Solar, LLC related to an impact study. The Company clarified it was a "*customer payment for a solar project application*"

Account #581, Load Dispatching. The FERC Form 1 amount of $126,630 was verified to the following GP Accounts January through September 2022:

8830-2-9851-51-5010-5810	Load Dispatching	$ 1,189.24
8830-2-9851-51-5400-5810	Load Dispatching	$ 99,359.13
8830-2-9853-51-5010-5810	Load Dispatching	$ 8,014.13
		$108,562.50

The 3 GP amounts were rolled into the following 10 SAP accounts:

50000010581000	Salaries and Wages	$ 129,066.73
50001010581000	Overtime	$ (592.31)
50005010581000	AllocCorp Lbr Leg	$ 1,149.05
50010010581000	Vacation & Other TO	$ 2,331.11
50500010581000	Other Operating Exp	$ (8,201.83)
50510010581000	Cost Alloc to Cap	$ (9,891.41)
70200010581000	BS Lbr Offset	$ 5,113.65
80300010581000	Assess Lbr	$ 8,597.41
80311010581000	Assess OH Benefit	$ 206.97
85300010581000	Assess Lbr-Intrc	$ (1,149.05)
		$ 126,630.32

Audit verified that the starting September balance in SAP agrees with the GP ending September balance.

The total overall SAP amount of $126,630 agrees with FERC Form 1 and filing schedule RR-2.1 and RR-2.6. This account reflected a 30% decrease from calendar year 2021.

All the net activity from January 2022 to September 2022 in the former GP accounts 9851-51-5010-581 and 9853-51-5010-5810 were rolled into SAP account <u>50000010581000.</u> The 2 former GP accounts reflected 9 weeks of payroll and 3 bonus accruals and 2 accrual reversals from 1/1/22 to 9/30/22. Audit notes that the net activity former GP account 9851-51-5400-5810 was also rolled into SAP account 50000010581000 and included amortization of prepaid expenses and 1 P-Card expense totaling $45.34.

The SAP account 50000010581000 reflected maintenance costs, an interest charge with an interest corrective entry, and 2 charges for Schneider Electric totaling $7,164.89 and $3,615.95. The Company advised the transactions were amortization expenses both noted to be amortized from "1/2022 – 12/2022". The Company further clarified they were "monthly amortization of maintenance agreement". SAP account 80300010581000 (Assess Lbr) had 1 November payroll entry for an unknown specified time period and in December there were 3 payroll entries and payroll reversals for unknown time periods. There were also 7 allocation burden entries, each entry totaling $5,113.65 with an accompanying reversal entry. Audit reviewed 2 credit entries entitled "GSE Missed A&G Assessment Correction 12.2022". The Company advised the credits were part of settlement agreement and was part of a larger year end journal entry. The Company noted that "*these entries do not relate to any settlement agreements or dockets approving missed assessments…The use of the term "settlement" by the Company in this context relates to the settlements process within SAP. That is consistent with the description of the process contained in the "Customer Information System and General Ledger" section of the audit report. In SAP, "settlement" is the process in which costs accumulated on one cost object is moved or "settled" to its settlement cost object. The most common example is WBS settlements. A WBS is configured with a settlement rule that determines where the costs initially incurred on the WBS settles after the settlement process is run. For an OpEx WBS, the settlement rule is usually the cost center where those costs would be budgeted. For a CapEx WBS, the settlement rule is the CWIP balance sheet GL account.*

Assessment is the process in which costs accumulated on one cost object (usually a cost center) are allocated to multiple cost objects (usually capital WBSs) based on the pre-configured rules. It's a process to spread indirect overhead charges to specific projects. The key components of an assessment cycle include: the sending cost object (usually a cost center), the receiving cost objects (usually capital WBS's) and a base (usually labor or total projects) that is used to determine what percentage of OH costs each receiving cost object would be allocated. An example of this is the A&G assessments process which allocates a portion of indirect labor costs associated with back office A&G employees to capital projects."

Account #582, Station Expenses $152,948 per FERC Form 1. The filing schedule RR-2.6 reflected the same accounts and total:

50000010582000	Salaries and Wages	$ 137,514.41
50030010582000	Outside Svs	$ 1,986.48
50500010582000	Other Operating Exp	$ 815.82
80000010582000	Lbr Alloc	$ 12,631.19
		$ 152,947.90

Audit notes that the former GP account 8830-2-9851-51-5010-5820 included all payroll transactions and reconciliation entries while GP account 8830-2-9851-51-5405-5820 included monthly fleet spread charges and payments to outside vendors. As with many GP accounts the net activity was initially rolled into 1 SAP account 50000010582000 with corrective entries made in December 2022.

In GP 8830-2-9851-51-5405-5820 Audit reviewed the activity and noted the following:

4 invoices for Chippers	$ 16,105.00
2 invoices for Asplundh Tree Expert Co.	$ 3,045.15
6 invoices for Avedisian Landscape & Irrigation	$ 3,575.00
6 invoices for Joe Gauci Landscaping LLLC	$ 4,615.00
3 invoices for JP Pest Services	$ 817.00
3 invoices for Kevin Dube - Dube Property Maintenance	$ 2,250.00
3 invoices Landmark Property Maintenance	$ 2,165.00
1 invoice for United Power Group, Inc.	$ 900.00
P-Card Expenses	$ 177.43
Fleet Spread	$ 631.14
Net accruals and reversals	$ 0.03
TOTAL EXPENSES THROUGH 9/30/22	**$ 34,280.75**

Overall, account 582 reflects a 42% decrease in expenses for year-end 2022 compared to year-end 2021.

Account #583, Overhead Line Expenses $ 1,170,626 per the FERC Form 1 and the filing schedule RR-2.6 was verified to the following SAP accounts:

50000010583000	Salaries and Wages	$	705,708.23
50001010583000	Overtime	$	5,964.61
50005010583000	AllocCorp Lbr Leg	$	(14,727.09)
50010010583000	Vacation & Other TO	$	3,648.98
50030010583000	Outside Svs	$	135,551.62
50500010583000	Other Operating Exp	$	137,355.32
50530010583000	Clr CIAC CWIP P&L	$	-0-
80000010583000	Lbr Alloc	$	189,247.00
80300010583000	Assess Lbr	$	(6,849.70)
85300010583000	Assess Lbr-Intrc	$	14,727.09
		$	1,170,626.06

Total Account #583 agrees with the filing schedule RR-2.1 and RR-2.6. Overall, account 583 reflects a 31% increase in expenses for year-end 2022 compared to year-end 2021.

Audit requested supporting documentation for the following four clearing entries in Account 583, which was provided by the Company on 9/16/23. All offset entries were made to Stores Expense Undistributed #8830-2-0000-10-1380-1630 and CWIP 8830-2-0000-10-1618-1070:

1. Clearing Entry: 8830 Clear GL#1380-1630 SEP22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ 304,886.97	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ -	$ (194,365.44)
8830-2-0000-10-1618-	Construction Work In Progress	$ -	$ (64,788.48)
8830-2-9851-51-5410-	Overhead Line Expenses	$ -	$ (45,733.05)
		$ 304,886.97	$ (304,886.97)

2. Clearing Entry: 8830 CLear GL#1380-1630 AUG22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ -	$ (114,620.83)
8830-2-0000-10-1618-	Construction Work In Progress	$ 73,070.78	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ 24,356.93	$ -
8830-2-9851-51-5410-	Overhead Line Expenses	$ 17,193.12	$ -
		$ 114,620.83	$ (114,620.83)

3. Clearing Entry: 8830 CLear GL# 1380-1630 MAR22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ -	$ (69,906.28)
8830-2-0000-10-1618-	Construction Work In Progress	$ 44,565.25	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ 14,855.09	$ -
8830-2-9851-51-5410-	Overhead Line Expenses	$ 10,485.94	$ -
		$ 69,906.28	$ (69,906.28)

4. Clearing Entry: 8830 Clear GL# 1380-1630 FEB22

Account Number	Account Description	Debit Amount	Credit Amount
8830-2-0000-10-1380-	Stores Expense Undistributed	$ -	$ (67,793.29)
8830-2-0000-10-1618-	Construction Work In Progress	$ 43,218.22	$ -
8830-2-0000-10-1618-	Construction Work In Progress	$ 14,406.08	$ -
8830-2-9851-51-5410-	Overhead Line Expenses	$ 10,168.99	$ -
		$ 67,793.29	$ (67,793.29)

Audit also reviewed the following 9 invoices:

	VENDOR	DATE	AMOUNT
1	Richard Paradie	9/20/2022	$ 12,134.72
2	Town Of Salem NH/Orig. Doc. #15866	9/21/2022	$ 11,411.50
3	Stella-Jones Corporation/Orig. Doc. #Rct00061596	6/29/2022	$ 11,297.00
4	Stella-Jones Corporation/Orig. Doc. #Rct00061427	6/14/2022	$ 11,839.24
5	JCR Construction Co. Inc.	6/7/2022	$ 11,648.06
6	Stuart C. Irby Co./Orig. Doc. #Rct00061055	5/16/2022	$ 21,138.90
7	Northeast Public Power Association/Orig. Doc. #70660	3/31/2022	$ 10,095.00
8	Arthur J. Hurley Co., Inc./Orig. Doc. #Rct00060522	3/29/2022	$ 10,470.00
9	Itron Inc/Orig. Doc. #609119	2/25/2022	$ 17,353.92

Invoices consisted of employee reimbursement for conference attendance, Town charges for police details, utility poles, construction charges for foreman and linemen, material charges such as clamps and arm bolts, Apprentice Line Work Program charges for 3 employees, 750 foot reels, and single contact connectors.

Account #584 Underground Lines $14,326 per Schedules RR-2 was verified to the following SAP general ledger accounts and to the total shown on line 138, page 320-323 of the FERC Form

50000010584000	Salaries and Wages	$ (271.66)
50001010584000	Overtime	$ 378.42
50030010584000	Outside Svs	$ 13,763.66
50500010584000	Other Operating Exp	$ -0-
80000010584000	Lbr Alloc	$ 455.46
		$ 14,325.88

Audit tested the largest invoice totaling $10,912.50 in the SAP GL. The invoice was provided on 9/23/23 and was from USIC Locating Services, LLC. Charges were a flat fee for location services, after hours charges, additional footage charges, and 272 “footage site visits”. 2 GP GL accounts reflected 3 weeks of payroll for 6/26/22 – 7/9/22 along with 1 payroll accrual entry and one job/work order entry.

Total Account #584 reflects a 322% increase in expenses for year-end 2022 compared to year-end 2021.

Account #585 Street Lighting and Signal Expenses $39,132 per the FERC Form 1 and the filing schedules RR-2 and RR-2.6 was verified to the following accounts:

GP account as of 9/30/22:

8830-2-9851-51-5010-5850	Street Lighting & Signal Systems	$32,066.53

SAP accounts through 12/31/22:

50000010585000	Salaries and Wages	$ 30,738.43
50500010585000	Other Operating Exp	$ -
80000010585000	Lbr Alloc	$ 8,393.32
		$ 39,131.75

Account 585 had a total overall increase of 49% in 2022 expenses compared to 2021. Audit reviewed the account activity and noted weekly payroll, bonus accruals, and 2 reclassification entries. No further testing was performed.

Account #586 Meter Expenses $ 315,949 per the FERC Form 1 and the filing schedules RR-2 and RR-2.6 was verified to the following GP accounts through 9/30/22:

8830-2-9851-51-5010-5860	Meter Expenses	$ 180,873.97	Labor
8830-2-9851-51-5425-5860	Meter Expenses	$ 60,641.38	Expenses
		$ 241,515.35	

The GP activity through 9/30/2022 was rolled into the following SAP accounts, with year-end balances of::

50000010586000	Salaries and Wages	$ 302,977.30
50001010586000	Overtime	$ 84,758.44
50005010586000	AllocCorp Lbr Leg	$ (124,878.77)
50010010586000	Vacation & Other TO	$ (12,832.41)
50050010586000	Equip & Machin Rents	$ 1,034.13
50330010586000	Misc Other Deduction	$ 2,214.01
50500010586000	Other Operating Exp	$ -
80000010586000	Lbr Alloc	$ 22,156.38
80300010586000	Assess Lbr	$ (96,504.81)
80302010586000	Assess Material	$ 2,315.04
80304010586000	Assess Other	$ 363.22
80305010586000	Assess Fleet - Asses	$ 118.32
80308010586000	Assess Meals	$ 3,987.09
80308510586000	Assess Travel	$ 4,846.25
80311010586000	Assess OH Benefit	$ 516.09
85300010586000	Assess Lbr-Intrc	$ 145,344.55
85308010586000	Assess Meals -Intrc	$ 636.96
85308510586000	Assess Travel-Intrc	$ 5,773.62
85311010586000	As OH BenIntrc	$ (26,876.36)
		$ 315,949.05

Account 586 overall had a 63% increase in expenses in 2022 over calendar year 2021.

Expenses consisted of weekly payroll entries, reimbursements to employees, payments for p-card purchases, payments to vendors, fleet spreads, reclassifications, and accruals and reversals. Audit requested the detailed journal entry information regarding the following 4 general ledger transactions in the SAP GL 50500010586000 that were all dated 12/31/22. 3 entries part of the same year-end journal entry (Entry #100085265):

1. Journal Entry #100086917

Account Number	Account Description	Debit Amount	Credit Amount
50500010920000	Maint. of Station Equip - Other Operating Exp.	$ 622,881.48	
UNKNOWN	**UNKNOWN**	**$ 626,192.38**	
50500010586000	Meter Expenses - Other Operating Exp		$ (1,249,073.86)
		$ 1,249,073.86	$ (1,249,073.86)

2. Journal Entry #100085265

Account Number	Account Description	Debit Amount	Credit Amount
50500010586000	Meter Expenses - Other Operating Exp	$ 646,148.89	
50500010586000	Meter Expenses - Other Operating Exp	$ 385,721.64	
50500010586000	Meter Expenses - Other Operating Exp	$ 195,852.29	
50500010999999	Default - Other Operating Exp	$ 1,069,835.09	
UNKNOWN	**UNKNOWN**		**$ (2,297,557.91)**
		$ 2,297,557.91	$ (2,297,557.91)

The Company originally did not provide detailed information, just highlighted transactions to where the partial amounts were offset. In journal entry #10085265 the Company responded that all 3 debit transactions in account 586 were offset to account 999 or a "Default" account, however the transaction they provided was another debit entry and an offsetting credit entry could not be identified. Liberty subsequently provided the complete journal entry #100086917 which included 39 specific line items and the complete journal entry #100085265, which included 170 specific line items. Audit verified that the journal entries include some combination of offsetting accounts. However, due to the number of line items of each of the entries, the specific offsets to these portions of the entries listed as UNKNOWN could not be determined. Audit does confirm that the entries include the $622,881.48 and $(1,249,073.86) individually, as well as the four debits listed for journal entry #100085265.

Journal Entry #100086917 included:

66 debit entries to numerous accounts summing to	$5,315,910.38	
104 credit entries to numerous accounts summing to		$(5,315,910.38)

Journal Entry #100085265 included:

32 debit entries to numerous accounts summing to	$3,052,076.63	
7 credit entries to numerous accounts summing to		$(3,052,076.63)

Audit also reviewed the following 2 vendor invoices from the GP GL that showed charges for transformers and terminals.

- GEC Durham Industries, Inc. 4/13/2022 $12,583.20
- GEC Durham Industries, Inc. 2/14/2022 $13,049.40

Audit found 2 entries in the GP GL with a description of "Precap Meter Installation" totaling $125,747.35. These entries were credited to the meter expense account and debited to account 8830-2-0000-10-1618-1070. Audit could not trace any similar entries in the SAP GL. Refer to the Plant section of this report regarding the pre-capitalization policy.

<u>Account #587</u> Customer Installations Expenses $48,988 per the FERC Form 1 agrees with the filing schedule RR-2.1, RR-2.6 and the following SAP general ledger accounts:

50000010587000	Salaries and Wages	$ 45,670.48
50030010587000	Outside Svs	$ 1,050.00
50093010587000	Util Exp-Cust Instal	$ 219.64
50500010587000	Other Operating Exp	$ -0-
80000010587000	Lbr Alloc	$ 2,047.40
		$ 48,987.52

Customer Installation Expense $48,897.52 represents a 10% decrease from the 2021 year-end balance.

<u>Account #588</u> Miscellaneous Expenses $1,613,700 per the FERC Form 1 agrees with the filing schedule RR-2.1 and RR-2.6 which reflected the following SAP general ledger accounts:

50000010588000	Salaries and Wages	$ 290,214.80
50001010588000	Overtime	$ 8,732.64
50005010588000	AllocCorp Lbr Leg	$ (27,089.68)
50010010588000	Vacation & Other TO	$ 3,589.08
50030010588000	Outside Svs	$ 91,348.32
50070010588000	Land&Property Rents	$ 4,353.62
50121010588000	Fleet-Fuel	$ (28,298.54)
50230010588000	Facility Costs	$ 93,201.47
50231010588000	Facility Costs-Maint	$ 1,128.16
50232010588000	Facility Costs-Secur	$ 90.00
50500010588000	Other Operating Exp	$ 1,038,432.46
50510010588000	Cost Alloc to Cap	$ (3,314.56)
70200010588000	BS Lbr Offset	$ (5,092.63)
80000010588000	Lbr Alloc	$ 111,641.00
80300010588000	Assess Lbr	$ 264.70
80302010588000	Assess Material	$ 2,630.46
80304010588000	Assess Other	$ 865.28
80305010588000	Assess Fleet - Asses	$ 63.12
80308010588000	Assess Meals	$ 828.02
80308510588000	Assess Travel	$ 3,022.44
85300010588000	Assess Lbr-Intrc	$ 20,946.09
85303010588000	As Serv-Intrc	$ 7,960.00
85311010588000	As OH BenIntrc	$ (1,816.41)
		$ 1,613,699.84

Account 588 overall had a 31% increase in expenses in 2022 over calendar year 2021.

Audit reviewed the following 4 invoices:

	VENDOR	DATE		AMOUNT
1	Leighton A. White Complete Sitework Services	12/21/22	$	87,460.00
2	Wright Tree Service	12/27/22	$	11,793.80
3	USIC Locating Services LLC	7/31/2022	$	13,117.78
4	USIC Locating Services LLC	7/11/2022	$	12,746.24

The Leighton A. White Complete Sitework Service invoice showed that $87,460 worth of work out of a total contract of $252,460 was completed. The invoice specified what the project was for "West Lebanon future facility clean up" and that 12/14/2022 "work was completed App #2". The remaining invoices were for tree removal, flat fees for utility location and prevention services.

Audit reviewed 2 vegetation management accruals totaling $98,645.97. The vegetation management accruals are for vegetation management estimates based on previous invoices from 7 different vegetation management companies' and expenses incurred but not yet paid.

Account #590 Maintenance Supervision and Engineering $13,943 per the FERC Form 1, was verified to the general ledger account 8830-2-9854-56-5010-5990 from January 2022 through September 2022. That activity was rolled into SAP accounts, reflected on the filing schedule RR-2.6 as:

50000010590000	Salaries and Wages	$13,469
50010010590000	Vacation and Other TO	$ 175
50500010590000	Other Operating Exp	$ -0-
80000010590000	Lbr Alloc	$ 299
		$13,943

The account reflects a decrease of 5% over the year ending 12/31/2021.

In the Great Plains ledger, there were 65 entries reflecting weekly payroll entries, accruals and reversals. In the SAP general ledger there were 9 carry forward charges accurately reflecting the GP ending balance as of 9/30/23. There was also 2 payroll entries and 3 reclassification entries.

Account #591 Maintenance of Structures $129,865 per the FERC Form 1 represents a 5% decrease from 2022year end. The figure was verified to the filing schedule RR-2, and to the following general ledger accounts:

50000010591000	Salaries and Wages	$105,704.19
50010010591000	Vacation & Other TO	$ 41.18
50030010591000	Outside Svs	$ 790.00
50500010591000	Other Operating Exp	$ 20,630.32
80000010591000	Lbr Alloc	$ 2,698.90
		$129,864.59

The first account's activity reflected weekly payroll entries, accrual reversals, P-card entries and 2 vendor invoices.

Account #592 Maintenance of Station Equipment $238,334 per the FERC Form 1, was verified to the filing schedule RR-2 and to the following general ledger accounts:

50000010592000	Salaries and Wages	$ 131,558.74
50001010592000	Overtime	$ 1,410.85
50500010592000	Other Operating Exp	$ 77,510.98
80000010592000	Lbr Alloc	$ 27,853.81
		$ 238,334.38

Overall, the account decreased by 20% from the 2021 year-end balance. The SAP GL did not reflect any vendor invoices. In the former GP account 8830-2-0000-56-5210-5920 audit notes only 1 invoice for $731 was expensed. GP account 8830-2-9851-56-5010-5920 showed weekly payroll entries, accruals and reversals. Audit reviewed the activity in GP account 8830-2-9851-56-5210-5920 and noted the following:

Net accruals and reversals	$ 13,072.94
P-Card Expenses	$ 9,003.47
1 invoice AECOM Inc.	$ 7,900.00
1 invoice ARTHUR J. HURLEY CO., INC.	$ 582.50
1 invoice AVO MULTIAMP CORPORATION D/B/A MEGGER	$ 1,492.00
1 invoice COOPER POWER SYSTEMS	$ 1,132.44
1 invoice DENRON PLUMBING & HVAC DBA DENRON HALL	$ 595.00
2 invoices FIRST LINE ASSOCIATES INC	$ 1,110.51
3 invoices WW GRAINGER INC	$ 1,376.20
1 invoice GRANITE STATE PLUMBING & HEATING	$ 660.00
3 invoices HASTINGS FIBER GLASS PRODUCTS	$ 1,889.52
1 invoice KRISTEN LEHMAN	$ 80.00
1 invoice RAM PRINTING INC	$ 497.26
5 invoices TOWN OF SALEM NH	$ 7,433.50
7 invoices STAPLES BUSINESS ADVANTAGE	$ 5,805.78
16 invoices UNITED POWER GROUP, INC.	$ 34,855.00
4 invoices UNITED SITE SERVICES NORTHEAST INC	$ 1,561.86
2 invoices WEIDMANN ELECTRICAL TECHNOLOGY INC	$ 712.00
TOTAL EXPENSES THROUGH 9/30/22	**$ 89,759.98**

Account #593 Maintenance of Overhead Lines $5,452,702 per the FERC Form 1 represents an increase over the 2021 year-end balance of 18%. The 2022 was verified to filing schedule RR-2.6 associated with the following general ledger accounts. Audit verified the ending GP general ledger and the starting SAP balance.

24672010593000	Curr REC Obg Non-Reg	$ 3,675,811.00
50000010593000	Salaries and Wages	$ 568,816.34
50001010593000	Overtime	$ 4,281.72

50010010593000	Vacation & Other TO	$ 7,373.84
50030010593000	Outside Svs	$ 604,997.94
50123010593000	Fleet-Permit/Inspect	$ -0-
50330010593000	Misc Other Deduction	$ 2,423.97
50500010593000	Other Operating Exp	$ 3,510,153.97
80000010593000	Lbr Alloc	$ 754,654.22
		$ 9,128,513.00

As noted in **Audit Issue #1** and via response from the Company, $3,675,811.00 (shown above in GL REG account 24672010593000) should have been excluded from FERC account 593 and added to account 242. When this account is excluded, the remaining accounts shown in SAP account 593 match the filing amount of $ $5,452,702.00.

SAP account 50030010593000 included 585 charges and reversals or corrective entries for foresters/laborers, 4x4 vehicles, "laptops with software" and iPads. The 585 entries net total was $60,599.34. It is unclear why portions of these charges were reversed. There were also 145 various vendor invoices totaling $580,358.67.

Audit also found 3 credit entries related to storm costs entitled "Trans chrgs booked to Storm 2108 in error s/b 2208" and "Trans Stm 2209 Outside Services from exp to defer" that totaled ($37,379.46).

Furthermore, Audit found 2 debit entries in SAP Account 50030010593000 relating to disallowed storm costs. The first entry entitled "Per PUC Audit - Stm 2113 Costs Disallow – Transfer" totaled $1,200. Per the Audit Report issued on September 9, 2022 relating to Docket DE 22-019, the costs were related to 2 disallowed charges from Winter Storm Orlena in 2021, refer to Audit Issue #3. The second debit entry totaled $211.98 and was entitled "Per PUC Audit - Stm 2102 Costs Disallow – Transfer" was also related to Winter Storm Orlena, refer to Audit Issue #1 for further information on the disallowance of costs. Audit also found in GP general ledger account 8830-2-9851-56-5210-5932 an additional entry entitled "Trans Chrgs Storm 2102 to 2103" for $6,260.63. This disallowed storm cost was identified as Audit Issue #2 in the same Audit Report issued on September 9, 2022 for Docket DE 22-019. Audit recommends that all 3 debit entries be considered non-recurring. **Audit Issue #18**

Audit reviewed the activity in the GP general ledger and noted the following in regard to vendor transactions:

1 invoice AIDASH INC	$	42,000.00
3 invoices AIRGAS	$	750.46
1 invoice AMERICAN CRANE COMPANY	$	2,930.00
1 credit ARTHUR J. HURLEY CO., INC.	$	(25.00)
313 invoices ASPLUNDH TREE EXPERT CO	$	2,022,293.01
2 invoices BENCHMARK GRAPHICS	$	443.18
1 invoice SPENCER BROUILLETTE	$	12.99

50 invoices CHIPPERS	$	167,158.75
1 voided invoice CLEARWAY INDUSTRIES LLC	$	(3,338.75)
7 invoices CONTROLPOINT TECHNOLOGIES INC	$	4,792.05
1 invoice EG CAPITAL LLC	$	2,779.31
1 invoice ELLIS WILLIAM C	$	8.49
28 invoices THOMAS KEOUGH JR. DBA ENVIRO ARBOR SOLUTIONS, LLC	$	430,394.22
5 invoices FIRESIDE HOTEL	$	10,201.88
1 invoice ADAM FORTUNATI	$	16.26
1 invoice SHAWN FUREY	$	398.36
1 invoice WW GRAINGER INC	$	352.92
1 invoice HEATHER GREEN	$	264.00
3 invoices TOWN OF HUDSON NH	$	3,097.50
48 invoices HUNTER NORTH ASSOCIATES LLC	$	23,475.00
1 invoice I.C. REED & SONS, INC.	$	18,995.47
7 invoices JCR CONSTRUCTION CO INC	$	88,835.97
1 invoice KAMCO SUPPLY CORP OF BOSTON	$	980.00
121 invoices LAKESIDE ENVIRONMENTAL CONSULTANTS INC	$	204,402.97
3 invoices MALLORY SAFETY & SUPPLY	$	605.00
32 charges for 99 RESTAURANT & PUB and 4 voided entries	$	3,341.65
6 invoices NORTHEASTERN LAND SERVICES DBA THE NLS GROUP	$	1,248.48
14 invoices NORTHERN TREE	$	92,212.45
1 invoice ORR & RENO, P.A.	$	1,447.00
1 invoice RICHARD PARADIE	$	149.17
2 invoices PARKER FENCE	$	25,800.00
2 invoices CALE PERRY	$	236.45
1 invoice TREVOR REYNOLDS	$	16.58
7 invoices TOWN OF SALEM NH	$	13,704.00
4 invoices STUART C IRBY CO	$	3,965.64
1 invoice TERRA SPECTRUM TECHNOLOGIES	$	22,667.00
1 invoice TOWN OF HAMPSTEAD	$	316.00
22 invoices TYNDALE COMPANY INC	$	6,306.65
2 invoices UNITED PARCEL SERVICE	$	62.93
8 invoices UTILITY SERVICE & ASSISTANCE INC	$	142,251.29
4 invoices VANASSE HANGEN BRUSTLIN INC	$	13,898.34
19 invoices WRIGHT TREE SERVICE, INC	$	287,369.91
1 invoice HART HALSEY LLC DBA EXTRA DUTY SOLUTIONS	$	584.34
TOTAL VENDOR INVOICES THROUGH 9/30/22	**$**	**3,637,401.92**

Audit requested supporting documentation for the largest invoice from Asplundh Tree Expert, Co. which totaled $333,319.96. The invoice was part of a 2021 contact totaling $551,986.77. $218,666.81 was paid in 2021 for mileage reimbursement for May – August 2021.

A note on the invoice indicated an incorrect invoice was received in November 2021 and adjustments were needed. The note further indicated that a corrected invoice was received 2/16/2022 and "entered 2/21/2022". The adjustment included a credit in the amount of $7,445.21 on the mileage already paid for in 2021. Audit confirmed a debit accrual in the amount of $281,017.96 was recorded in 2021 related to this contract. The credit entry was posted in 2022 leaving the balance of $52,302 of expenses paid in 2022 for 2021 costs. **Audit Issue #19**

Account #594 Maintenance of Underground Lines $167,310 per the FERC Form 1 represents an increase of 664% over the 2021 year-end figure. The total was verified to filing schedule RR-2, which reflects following general ledger accounts:

50000010594000	Salaries and Wages	$ 22,177.85
50030010594000	Outside Svs	$ 124,713.40
50500010594000	Other Operating Exp	$ 7,249.96
80000010594000	Lbr Alloc	$ 13,168.88
		$ 167,310.09

The GP general ledger reflected 75 payroll entries and 18 accruals and reversals. There were 5 invoices from 4 different vendors totaling $8,050.24 and 4 credit entries for various work orders that totaled ($6,701.08).

In SAP account 50030010594000 Audit tested the 3 largest invoices which were from the same vendor, Granite State Cable Splicing & Testing, LLC and together totaled $116,162.00. Work was performed between 10/1/22 – 12/19/22 and included excavation, underground cable replacement, hydroseed and loam, concrete repair or maintenance, PVC conduit, and the use of dump trucks or pull trucks, in addition to labor charges. The work appeared appropriate for the charges incurred.

Account #595 Maintenance of Line Transformers $3,701 per the FERC Form 1 represents an overall decrease of 90% from 2021. The 2022 total was verified to the filing schedule RR-2 and to SAP general ledger account 50000010595000.

The only transactions in the SAP general ledger were carry forward charges from the GP general ledger with no new transactions after 9/30/22. The GP general ledger consisted of 29 payroll entries summing to $4,095.43 and 5 accrual entries totaling ($394.80).

Account #596 Maintenance of Street Lighting and Signal Systems $39,278 per the FERC Form 1 is a decrease of 8% from calendar year 2021. The total agrees with the filing schedule RR-2 and was verified to the following SAP general ledger accounts:

50000010596000	Salaries and Wages	$ 27,114.73
50010010596000	Vacation & Other TO	$ 30.96
50500010596000	Other Operating Exp	$ 1,992.00
80000010596000	Lbr Alloc	$ 10,140.74
		$ 39,278.43

Transactions consisted of weekly payroll entries, payroll accruals and 1 vendor invoice for Hunter North Associates, LLC summing to $380.00.

Account #597 Maintenance of Meters $53,762 per FERC Form 1 and the filing schedule RR-2 was verified to the following general ledger accounts:

50000010597000	Salaries and Wages	$ 26,822.80
50001010597000	Overtime	$ 77.68
50500010597000	Other Operating Exp	$ 11,202.33
80000010597000	Lbr Alloc	$ 15,658.98
		$ 53,761.79

The 12/31/2022 total represents an increase from the 12/31/2021 balance by 19%. The GP general ledger reflected 80 payroll entries, 16 payroll accrual entries, 10 vendor invoices and 1 P-card entry. The Salaries and Wages account 50000010597000 reflects 10 carry forward charges from the GP general ledger however 1 entry is dated 10/31/22. There was also 1 transaction coded only as “SA” with a description of “Timesheet Conversion”. According to the Company. The code SA translates to a ”G/L Account Document”. In account 80000010597000 Labor Allocation account, all 80 entries in the account were coded as “WF” which translates to “WFS Integration”.

Account #598 Maintenance of Miscellaneous Distribution Plant $59,472 per the FERC Form 1 represents an increase of 25% from the prior year. The amount was verified to the filing schedule RR-2.6 and to the following SAP general ledger accounts:

50000010598000	Salaries and Wages	$29,806.32
50030010598000	Outside Svs	$ 4,544.74
50330010598000	Misc Other Deduction	$ 340.96
50500010598000	Other Operating Exp	$24,780.36
		$59,472.38

The SAP general ledger reflected 3 reclassification entries and 3 vendor invoices totaling $4,885.70 and 18 carry forward entries from the GP general. The GP general ledger reflected 112 weekly payroll entries, 11 vendor invoices summing to $14,085.38, 8 P-Card expenses, and 1 reclassification entry. Audit requested supporting information for the largest invoice from Bashlin Industries, Inc. totaling $11,779.30. The charge was an accrual of a total of 10 invoices for materials and freight. Invoices included costs for materials such as linemen body harnesses, linemen belts, climber pads and aluminum pole climbers. 1 invoice totaling $465.10 (invoice number 323443) has a “shipped date” of 3/28/2023 which would be outside of the test year of 2022 The invoice does not reflect when the order was placed. **Audit Issue #19**.

Customer Account Expenses, per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Customer Account Expenses decreased 5%.

	12/31/2021	12/31/2022	% change
901 Supervision	$ 48,490.00	$ 45,592.00	-6%
902 Meter Reading Expenses	$ 345,953.00	$ 353,272.00	2%
903 Customer Record and Collection Expenses	$1,129,379.00	$1,049,339.00	-7%
904 Uncollectible Accounts	$ 281,647.00	$ 272,932.00	-3%
905 Miscellaneous Customer Accounts Expenses	$ 29,720.00	$ 20,000.00	-33%
Total Customer Accounts Expenses	**$1,835,189.00**	**$1,741,135.00**	**-5%**

Each of the 90x accounts was verified to the filing schedule RR-2 and to the general ledger.

Account #901 Supervision $45,592 per the FERC Form 1 represents a decrease over the 2021 balance of 6%. The total was verified to the RR-2 schedule in the filing, and was tied to the general ledger accounts:

50000010901000	Salaries and Wages	$ 36,295.35
50001010901000	Overtime	$ (169.68)
50500010901000	Other Operating Exp	$ 0
80000010901000	Lbr Alloc	$ 9,502.08
		$ 45,591.75

Activity in the account was noted to be bi-weekly payrolls. Please see the *Payroll* section above for additional payroll information.

Account #902 Meter Reading Expenses $353,272 per the FERC Form 1 represents a decrease of 2% over the prior year. The total was verified to the RR-2 schedule in the filing, and was tied to the general ledger accounts:

50000010902000	Salaries and Wages	$ 260,785.24
50001010902000	Overtime	$ 83.03
50030010902000	Outside Svs	$ 47,148.93
50500010902000	Other Operating Exp	$ 1,739.87
80000010902000	Lbr Alloc	$ 43,514.76
		$ 353,271.83

The GP ledger reflected weekly payroll entries, payroll accruals and reversals, 12 invoices from CGI Technologies & Solutions totaling $94,635.60, 1 invoice from Honeywell Mercury Instruments summing to $867.

The SAP GL reflected 5 invoices totaling $56,498.93, 250 payroll entries totaling $46,548.58 and 5 reclassification entries.

<u>Account 903 Customer Records and Expenses</u> $1,049,339 was verified to the filing schedule RR-2 and to the FERC Form 1. The expense represents a 7% decrease from the 2021 total. Audit verified the 2022 figure to the following general ledger accounts:

50000010903000	Salaries and Wages	$	503,919.70
50001010903000	Overtime	$	8,966.19
50005010903000	AllocCorp Lbr Leg	$	(17,824.27)
50006010903000	AllocReg Lbr Leg	$	7,604.30
50010010903000	Vacation & Other TO	$	(399.22)
50030010903000	Outside Svs	$	17,749.96
50150010903000	Advertising Expenses	$	1,976.55
50240010903000	Legal Expenses	$	40.82
50500010903000	Other Operating Exp	$	(1,590.23)
50507010903000	Cust Rec&Cltn Exp	$	421,546.05
50510010903000	Cost Alloc to Cap	$	(63,230.85)
70200010903000	BS Lbr Offset	$	(1,082.76)
80000010903000	Lbr Alloc	$	162,460.90
80300010903000	Assess Lbr	$	(10,375.58)
80304010903000	Assess Other	$	520.74
80308010903000	Assess Meals	$	345.79
80308510903000	Assess Travel	$	823.85
80311010903000	Assess OH Benefit	$	62.54
85300010903000	Assess Lbr-Intrc	$	20,176.13
85304010903000	Assess Other-Intrc	$	8.09
85308010903000	Assess Meals -Intrc	$	49.01
85311010903000	As OH BenIntrc	$	(2,408.96)
			$1,049,338.75

The GP general ledger reflected 1,872 weekly payroll entries totaling $414,777.15, payroll accruals and reversals. There were also 90 entries totaling $3,927.44 entitled IC: CS0NH, Journal:XXXXXXX CCSM-PYMT, that the Company has previously indicated were transactions that are "good faith" courtesy adjustments to customers' bills for the reversal or forgiveness of certain charges, including late payment charges, connection fees, minor balances, etc. Some of the higher dollar subtotals for vendor invoices were the following:

27 invoices FISERV	$237,606.26
18 invoices PITNEY BOWES	$ 9,546.94
8 invoices LANGUAGE LINE SERVICES, INC.	$ 8,633.51
14 invoices EQUIFAX INFORMATION SVCS LLC	$ 5,112.10
	$260,898.81

The SAP General ledger reflected 35 vendor invoices totaling $19,092, 53 payroll entries totaling $9,201.61, payroll accrual and reversals, reclassifications and 6 entries related to customer surveys that totaled $8,381.75.

Account 904 Uncollectible Accounts $272,931.99 (rounded per the FERC Form 1) was verified to the filing as part of the overall schedule RR-2.7. RR-3.10, the Uncollectible Expense Factor Workpaper reflects the 2022 Uncollectible Expense as $486,165. It is unclear from where that figure was derived. Audit compared the changes in the account 904 since the prior 2018 rate case, and notes the following:

		12/31/2019		12/31/2020		12/31/2021		12/31/2022	
904	Uncollectible Accounts	$ 152,841	123%	$ 233,314	53%	$ 281,647	21%	$ 272,932	-3%

2019 was the first year after the previous test year, and saw a 123% increase in the Uncollectible Accounts expense account 904. 2020 reflected a 53% increase over the 2019 expense figure, the 2021 reflected a 21% increase over 2020. The test year saw a modest 3% decrease over the 2021 figure.

Audit reviewed the 2022 Great Plains and SAP accounts and related activity:
Great Plains activity January through September 2022:

8830-2-9865-80-8660-9040	Uncollectible Accounts	$ 401,970.76
8830-2-0000-80-8660-9041	Bad Debt Expense – Commodity	$(159,548.61)
	Activity through September 30, 2022	$ 242,422.15

The net Great Plains activity was rolled into SAP account 502000904. At year-end, the Uncollectible Expense total of $272,931.99 was the sum of:

Bad Debt Write-off	10904000 Uncoll A/cs—FERCE 502000904	$ 188,737.33
Bad Debt IVA	10904000 Uncoll A/cs—FERCE 502010904	$ 1,391,495.49
Bad Debt Manual Adj	10904000 Uncoll A/cs—FERCE 502020904	$(1,307,300.83)
	FERC Form 1, account 904	$ 272,931.99

Audit requested clarification or Bad Debt IVA, and was told that the Individual Value Adjustments (IVA) account in SAP "*automatically calculates and processes journal entries for bad debt expense. This automatic calculation is reversed on a monthly basis, manually calculated, and a new journal entry is processed.*" Offsets to the Great Plains Uncollectible Accounts -8660-9040 $401,970.76 were credited to the Reserve for Bad Debt Accrual, account 8830-2-0000-10-1102-1443, which was rolled into SAP account 11020010144000, Provision for Uncollectible Accounts. At 9/30 2022 the Great Plains balance in the -1443 account was $(873,859.15). At 12/31/2022, that balance reflected $(2,361,544.29)

Activity in the Great Plains Bad Debt Expense-Commodity account 8830-2-0000-80-8660-9041, reflected monthly credits relating to Commodity over/under calculations. Offsets were booked to 8830-2-0000-10-1101-1423 A/R Under Collect-Default/LR Sv. The balance of the GP -1423 account at 9/30/2022 was $2,127,657.97. The roll forward into SAP was combined with account 8830-2-0000-10-1101-1429 A/R REC Obligation $3,675,811.00 for a total SAP beginning balance of account 13080010142000 of $5,803,468.97.

<u>Account 905 Miscellaneous Customer Accounts Expenses</u> $20,000 was verified to the filing schedule RR-2 and to the FERC Form 1. The expense represents a 33% decrease from the 2021 total. Audit verified the 2022 figure to the following SAP general ledger accounts:

50000010905000	Salaries and Wages	$16,000.00
50030010905000	Outside Svs	$ 4,000.00
50500010905000	Other Operating Exp	$ -0-
		$20,000.00

Between both GP and SAP general ledger the only transactions were 10 payments to Phoenix Electronic Business Solutions, LLC dba Systrends USA, each totaling $2,000 and 2 reclassification entries.

<u>Customer Service and Information Expenses</u> per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Customer Service and Information Expenses decreased 33%.

		12/31/2021	12/31/2022	% change
909	Informational and Instructional Expenses	$ 72,065.00	$ 97,960.00	36%
910	Miscellaneous Customer Service and Informational Expenses	$ 1,482.00	$ -	-100%
	Total Customer Service and Informational Expenses	**$ 73,547.00**	**$ 97,960.00**	**33%**

<u>Account 909 Informational and Instructional Expenses</u> $97,960 per the FERC Form 1 represents a decrease of 36% from the 2021 balance. Audit verified the $97,960 to the following SAP general ledger accounts:

50000010909000	Salaries and Wages	$ 24,257.33
50150010909000	Advertising Expenses	$ 61,557.67
50500010909000	Other Operating Exp	$ 10,688.00
85400010909000	WBS ST Lbr-Intrc	$ 1,296.64
85404010909000	WBS ST Other-Intrc	$ 160.60
		$ 97,960.24

Between both the GP and SAP general ledger, entries consisted of weekly payroll, payroll accruals and reversals, marketing accruals and 22 vendor invoices totaling $45,823.43. Audit tested one of the largest transactions for $21,000 entitled “NHE July 2022 Rates Mailing”. The expense was for a July mailing to customers that included the printing, proofs, folding, postage and mailing of letters to customers.

<u>Sales Expenses</u> per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Sales Expenses decreased 24% and was verified to filing schedule RR-2.

		12/31/2021	12/31/2022	% change
912	Demonstrating and Selling Expenses	$ 150.00	$ (10,827.00)	-7318%
913	Advertising Expenses	$ 252.00	$ -	-100%
916	Miscellaneous Sales Expenses	$ 208,419.00	$ 170,411.00	-18%
	Total Sales Expense	**$ 208,821.00**	**$ 159,584.00**	**-24%**

Account 912 Demonstrating and Selling Expenses ($10,827) is the sum of the following SAP general ledger accounts and was verified to RR-2 of the filing and FERC Form 1:

50000010912000	Salaries and Wages	$ 12,608.86
50005010912000	AllocCorp Lbr Leg	$ (4,283.25)
50010010912000	Vacation & Other TO	$ 3,369.69
50150010912000	Advertising Expenses	$ 882.12
50400010912000	AllocCorp Cap Leg	$ 318.00
50500010912000	Other Operating Exp	$(18,567.55)
50510010912000	Cost Alloc to Cap	$(22,392.47)
70200010912000	BS Lbr Offset	$ (3,222.09)
80000010912000	Lbr Alloc	$ 26,080.16
80300010912000	Assess Lbr	$(10,133.92)
80308510912000	Assess Travel	$ 230.62
85300010912000	Assess Lbr-Intrc	$ 4,560.92
85311010912000	As OH BenIntrc	$ (277.67)
		$(10,826.58)

The GP general ledger only consisted of 2 invoices from Jill M. Fitzpatrick totaling $882.12. The SAP general ledger however consisted of numerous credit entries labeled as marketing, payroll interest corrections, missed A&G assessments and true ups resulting in a large credit balance at the end of 2022. Audit questioned the Company as to the reason why there were so many entries as in previous years entries have always consisted of small vendor invoices and resulted in an overall -7318% decrease from calendar year 2021. The Company responded with the following:

The credit balance in FERC account 912 is mainly due to a correcting journal entry that was recorded in December 2022. Upon migration to SAP, the systems support team identified that the automatic template used to calculate capital costs had not processed correctly for October and November 2022, hence a reclass entry was done to correct the missed costs.

Audit is unsure if the automatic template has been corrected or if other template mitigations were processed correctly **Audit Issue #20**

Account 916 Miscellaneous Sales Expenses $ 170,411 was the FERC Form 1 balance and verified to filing schedule RR-2 and the following SAP general ledger accounts:

50000010916000	Salaries and Wages	$ 167,170.03
50150010916000	Advertising Expenses	$ 3,240.90
		$ 170,410.93

Account 916 shows an overall 18% decrease in expenses from 2021. The GP general ledger consisted of payroll entries, accrual sand reversals and the following vendor invoices:

1 invoice ARAMARK UNIFORM AND CAREER APPAREL LLC	$ 56.97
1 invoice DINA SYLVESTER	$ 52.98
8 invoices JILL M. FITZPATRICK	$ 1,360.95
2 invoices GREATER SALEM CHAMBER OF COMMERCE	$ 975.00
	$ 2,445.90

Audit notes that the only entries in the SAP general ledger are carry forward charges.

Administrative and General Expenses per FERC Form 1 for the years ending 12/31/2021 and 12/31/2022 are reflected below. Overall, Administrative and General Expenses increased 77%.

	12/31/2021	12/31/2022	% change
920 Administrative and General Salaries	$ 2,883,082.00	$ 2,877,428.00	0%
921 Office Supplies and Expenses	$ 1,425,717.00	$ 2,287,231.00	60%
922 Administrative Expenses Transferred-Credit	$ (11,574,397.00)	$ (8,002,460.00)	-31%
923 Outside Services Employed	$ 3,048,900.00	$ 2,381,415.00	-22%
924 Property Insurance	$ 1,572,228.00	$ 1,589,317.00	1%
925 Injuries & Damages Insurance	$ 800,546.00	$ 927,599.00	16%
926 Employee Pensions & Benefits	$ 4,713,113.00	$ 3,697,502.00	-22%
928 Regulatory Commission Expenses	$ 547,366.00	$ 643,455.00	18%
930 Miscellaneous General Expenses	$ 61,330.00	$ (115,412.00)	-288%
931 Rent	$ 192,391.00	$ 205,469.00	7%
Total Administrative and General Operation Expenses	$ 3,670,276.00	$ 6,491,544.00	77%
935 Maintenance of General Plant	$ -	$ 7,320.00	100%
Total Administrative and General Maintenance Expenses	$ -	$ 7,320.00	100%
Total Administrative and General Expenses	**$ 3,670,276.00**	**$ 6,498,864.00**	**77%**

920 Administrative and General Salaries $2,877,428 per the FERC Form 1 represents a 0% change over the 2022 FERC Form 1 balance. The filing schedule RR-2.10, however, reflects $2,859,282, or $18,146 *less* than the FERC Form 1. The year end general ledger balance for 2022 was $2,618,649. The Company indicated that there were “mapping issues” when the Great Plains accounts were rolled into SAP on October 1, 2022. **Audit Issue #1**

A total of fifty-eight SAP general ledger account summed to the year-end GL total of $2,618,649.

50000010920000	Salaries and Wages	$725,045.00
50001010920000	Overtime	$1,942.32
50005010920000	AllocCorp Lbr Leg	$211,155.85
50006010920000	AllocReg Lbr Leg	$219,794.08
50010010920000	Vacation & Other TO	$(135,238.04)
50011010920000	SS/CPP/Emp Pension	$175.06
50011510920000	Ben Offst	$(69,745.72)
50012010920000	Unemp/Emp Insurance	$289.02
50015010920000	Medicare/Healthcare	$732,170.83
50017010920000	Group/Emp Ben	$9,791.79
50021010920000	LTIP	$48,550.53
50022010920000	Bonuses	$600,095.85
50050010920000	Equip & Machin Rents	$2,492.98
50122010920000	Fleet-Repair/Main	$34,387.80
50123010920000	Fleet-Permit/Inspect	$6,096.25
50254010920000	Prof Svs-Other	$10,780.84
50330010920000	Misc Other Deduction	$(4,155.20)
50500010920000	Other Operating Exp	$7,644.74
50510010920000	Cost Alloc to Cap	$(688,081.34)
50520010920000	AllocCorp NonLbr Leg	$(2,097.19)
50521010920000	AllocReg NonLbr Leg	$164,053.48
50550010920000	Collection System	$-
56104010920000	Amrt Fn Cst-Debt Dis	$436.52
59000010920000	Current FIT Exp	$-
59001010920000	Current SIT Exp	$-
59021010920000	Deferred FIT Exp	$-
59023010920000	Deferred Amrt EADIT	$-
70200010920000	BS Lbr Offset	$(8,392.44)
70211010920000	BS Ops OH Benefit	$(64,341.26)
80000010920000	Lbr Alloc	$247,748.73
80200010920000	Settle Lbr	$(29,403.31)
80202010920000	Settle Material	$(4,800.31)
80203010920000	Settle Services	$(656,848.01)
80300010920000	Assess Lbr	$8,392.44
80311010920000	Assess OH Benefit	$(127,913.92)
80311210920000	Assess Payroll Tax	$(9,139.79)
80311310920000	Assess Pension/OPEB	$360.81
80311410920000	Assess Prop Ins	$647.97
85300010920000	Assess Lbr-Intrc	$185,464.24
85302010920000	As Mat -Intrc	$1,231.24
85303010920000	As Serv-Intrc	$11,405.50
85304010920000	Assess Other-Intrc	$15,766.43
85308010920000	Assess Meals -Intrc	$83.33
85308510920000	Assess Travel-Intrc	$259.31
85311010920000	As OH BenIntrc	$12,222.54
85311210920000	As Prl Tx-Intrc	$2,119.78

85400010920000	WBS ST Lbr-Intrc	$(45,842.82)
85402010920000	WBS ST Mat-Intrc	$531.10
85403010920000	WBS ST Serv-Intrc	$487,794.12
85404010920000	WBS ST Other-Intrc	$524,241.09
85405010920000	WBS ST Fleet-Intrc	$27.34
85408010920000	WBS ST Meals-Intrc	$276.78
85408510920000	WBS ST Travel-Intrc	$775.59
85411010920000	WBS ST OH Ben-Intrc	$184,637.63
85411210920000	WBS ST OH PrlTx-intr	$1,270.30
85411310920000	WBS ST OH Pn/OPEB-in	$2,329.38
85411410920000	WBS ST OH PrIn-Intrc	$191.16
85411610920000	WBS ST Vaca-Intrc	$1,968.33
		$2,618,648.73

Audit reviewed the salaries and wages, overtime, labor allocation, vacation, pension and other payroll associated general ledger accounts during the detail review of payroll. See the *Payroll* section of this report for a detailed review.

Account 50500010920000, Other Operating Expense, contained 84 entries totaling $7,645. All 84 entries were to reclassify the expense to the correct regulatory account.

Account #921 Office Supplies and Expenses $2,287,231 per the FERC Form 1 does not agree with the filing or general ledger. Filing Schedule RR-2.10 lists $1,600,180 creating a $687,051.13 variance between the filing and FERC Form 1. The Company explained that the variance further:

"Schedule RR-2 includes an additional adjustment of $(687,051) to capitalize 85% of the physical inventory write-off that was recorded for GAAP purposes. This capitalized amount was not recorded for GAAP purposes to align with the Parent Company (APUC) Form 10-K filing and not have differences between those GAAP filings. This amount is correctly presented in the Revenue Requirement." **Audit Issue #1**. (underline added)

Furthermore, the variance between the FERC Form 1 and the SAP general ledger was related to mapping issues, reportedly $12,444.13 associated with Miscellaneous Current and Accrued Liabilities account 242 should have been mapped to account 921, and $14,040.00 in 921 should have been mapped to 107 CWIP **Audit Issue #1**.

Moreover, 1 SAP account was mapped to account 50320010999999, an unsettled WSB (Dues and Memberships) instead of 50320010921000 resulting in an immaterial difference of $50.85 between the Great Plains ending balance ledger as of 9/30/22 and the SAP starting ledger as of 9/30/22.

Overall, there was a 60% increase in expenses over the 2021 balance The SAP general ledger accounts, consisted of the following 43 accounts:

50030010921000	Outside Svs	$	7,125.32
50040010921000	Materials & Supplies	$	9,907.51
500400#	Materials & Supplies	$	-0-
50040510921000	M&C-NonStck Cntrl	$	9,667.95
50041010921000	M&C-Small Tools	$	66.09
50042010921000	M&C-Safety Supplies	$	4,790.63
50043010921000	M&C-Main Parts	$	101.52
50049510921000	M&C-Inventory Diff	$	808,295.01
500495#	M&C-Inventory Diff	$	-0-
50090010921000	Util Exp-Water & Sew	$	3,376.27
50092010921000	Util Exp-Heat & Elec	$	11,026.47
50110010921000	Trvl Exp	$	33,833.34
50111010921000	Trvl Exp-Accomm	$	2,532.20
50112010921000	Trvl Exp-Airfare	$	3,629.47
50113010921000	Trvl Exp-Rental	$	2,554.34
50114010921000	Trvl Exp-Mileage	$	1,538.52
50122010921000	Fleet-Repair/Main	$	-0-
50130010921000	Meals & Ent	$	8,081.59
50140010921000	Comm Exp-Telephone	$	754,436.79
50141010921000	Comm Exp-Cellular	$	78.92
50142010921000	Comm Exp-Internet	$	346.90
50210010921000	Comp Exp	$	1,355.97
50211010921000	Comp Exp-Repair	$	29,516.65
50213010921000	Comp Exp-Software	$	(36,569.35)
50270010921000	Office Related Exp	$	318,866.75
50271010921000	Postage	$	12.67
50300010921000	Rental Expense	$	9,872.00
50311010921000	Training	$	38,256.09
50320010921000	Dues & Memberships	$	40,465.37
50500010921000	Other Operating Exp	$	2,321.67
55057010921000	Cap Depr-Fleet	$	(35,406.70)
55110010921000	Unrealized Gns/Lss	$	(1,984.51)
56001010921000	Bank Charges	$	428.59
80000010921000	Lbr Alloc	$	1,264.44
80117010921000	OH A&G N-Labr	$	12,444.13
85302010921000	As Mat -Intrc	$	3,656.44
85304010921000	Assess Other-Intrc	$	271,502.90
85305010921000	As Fleet - Intrc	$	(20.90)
85308010921000	Assess Meals -Intrc	$	4,223.51
85308510921000	Assess Travel-Intrc	$	11,427.42
85400010921000	WBS ST Lbr-Intrc	$	10,887.71

85403010921000	WBS ST Serv-Intrc	$ (1,260.00)
85404010921000	WBS ST Other-Intrc	$ (28,934.43)
		$ 2,313,715.26

Audit is unsure of the significance of accounts 500400# or 500495# (highlighted in the table above) but there was no activity in either account.

Audit reviewed the GP general ledger and notes the following information in 8 subaccounts:

Office Supplies 9210 $170,564.39	
8830-2-9800-69-5130-9210	$ 73,110.45
8830-2-9810-69-5130-9210	$ 4,125.57
8830-2-9815-69-5130-9210	$ 3,483.90
8830-2-9820-69-5130-9210	$ 23,658.31
8830-2-9823-69-5130-9210	$ 1,604.93
8830-2-9825-69-5130-9210	$ 13,461.75
8830-2-9830-69-5130-9210	$ 22,248.40
8830-2-9835-69-5130-9210	$ 0.88
8830-2-9850-69-5130-9210	$ 142.02
8830-2-9851-69-5130-9210	$ 5,160.77
8830-2-9853-69-5130-9210	$ 1,136.78
8830-2-9854-69-5130-9210	$ 12,112.31
8830-2-9860-69-5130-9210	$ 4,822.92
8830-2-9865-69-5130-9210	$ 5,495.40
Subtotal of Accounts 9210	$170,564.39

Entries included p-card expenses, $6,269.09 in bank fees, 629 vendor invoices totaling $147,611.59 from vendors such as Staples, Hewlett-Packard Financial, Balance Professional, Inc., Comcast, Energy Tools, Inc. and PC Connection and Softchoice Corporation. Audit requested supporting documentation for 4 of the largest invoices from Verizon Wireless, PC Connection, Softchoice Corporation and Dell Latitude. The invoice from Verizon Wireless totaled $72,342.07 however only $21,702.62 was allocated to GSE. Charges were for phone usage for 845 cell phones and was posted to GP account 8830-2-9800-69-5131-9213.

The charge from PC Connection totaled $9,950.53. The charge was an allocation of 2 PC Connection invoices totaling $32,374.26. The Company provided that the GSE allocated portion of these invoices was $9,712.28 resulting in a $238.25 variance to what was recorded 8830-2-9800-69-5130-9210. **Audit Issue #21** The invoices included charges for two 100-inch professional Sony LED 4K and accessories for the screens, such as wall mounts and microphones.

The invoice from Softchoice (invoice #90550764) although requested, was not originally provided. The only information Audit was provided was the amount of the invoice totaling $16,250 and that that the invoice was dated 2/14/22. Further information subsequently provided shows a purchase of ten “Dell Latitude 7420”. A transaction entitled “Dell Latitude 7430 Btx Laptops-Install” totaling $14,040.00 was also reviewed. The supporting invoice was from Softchoice and was for 9 laptops each $1,560.

Travel 9211 $17,159.98

8830-2-9800-69-5131-9211	$ 362.70
8830-2-9810-69-5131-9211	$ 1,787.00
8830-2-9815-69-5131-9211	$ 4,088.47
8830-2-9820-69-5131-9211	$ 317.25
8830-2-9825-69-5131-9211	$ 6.11
8830-2-9850-69-5131-9211	$ 2,140.62
8830-2-9851-69-5131-9211	$ 1,540.82
8830-2-9854-69-5131-9211	$ 3,694.91
8830-2-9860-69-5131-9211	$ 3,222.10
Subtotal of Accounts 9211	$ 17,159.98

The overall 31 entries included direct non-labor accruals, p-card expenses, specific job reimbursements. Due to timing, further support for these invoices was not requested.

Utilities 9212 ($44.77)

8830-2-0000-69-5131-9212	$ (101.84)
8830-2-9800-69-5131-9212	$ 57.07
Subtotal of Accounts 9212	$ (44.77)

Communication 9213 $652,953.62

8830-2-9800-69-5131-9213	$555,529.01
8830-2-9820-69-5131-9213	$ 43.52
8830-2-9853-69-5131-9213	$ 97,381.09
Subtotal of Accounts 9213	$652,953.62

There were 262 vendor entries to vendor such as Breezeline, Cen-Com, Comcast, Consolidated Communications, DTN, LLC, Time Warner Cable, Verizon Business Solutions and Windstream. There were also intercompany cell phone charges and amortization of pre-paid expenses.

Dues & Membership Fees 9214 $ $33,699.77

8830-2-9815-69-5131-9214	$ 1,234.07
8830-2-9825-69-5131-9214	$ 50.85
8830-2-9854-69-5131-9214	$ 208.00
8830-2-9860-69-5131-9214	$ 23,449.35
8830-2-9868-69-5131-9214	$ 8,757.50
Subtotal of Accounts 9214	$ 33,699.77

Memberships included NH Home Builders Association, the Rotary Club of Great Salem, the New Hampshire Sustainable Energy Association dba Clean Energy NH and the Greater Portsmouth CC dba Chamber Collaborative Greater Portsmouth among other associations.

Training 5131-9215 $13,398.78	
8830-2-9800-69-5131-9215	$ 118.44
8830-2-9810-69-5131-9215	$ 2,144.03
8830-2-9812-69-5131-9215	$ 4,177.38
8830-2-9815-69-5131-9215	$ 3,017.12
8830-2-9820-69-5131-9215	$ 17.40
8830-2-9851-69-5131-9215	$ 1,074.75
8830-2-9854-69-5131-9215	$ 2,849.66
Subtotal Accounts 5131-9215	$13,398.78

Office Supplies – Head Office 5130-9215 $102,504.61	
8830-2-9800-69-5130-9215	$ 97,702.89
8830-2-9811-69-5130-9215	$ 3,126.13
8830-2-9815-69-5130-9215	$ 443.11
8830-2-9820-69-5130-9215	$ 36.63
8830-2-9850-69-5130-9215	$ 835.91
8830-2-9865-69-5130-9215	$ 257.06
8830-2-9868-69-5130-9215	$ 102.88
Subtotal of Accounts 5130-9215	$102,504.61

Meals and Entertainment 9216 $340.53		
8830-2-9835-69-5130-9216	$	28.56
8830-2-9851-69-5130-9216	$	256.59
8830-2-9860-69-5130-9216	$	20.99
8830-2-9865-69-5130-9216	$	34.39
Subtotal of Accounts 9216	$	340.53

In the SAP general ledger, as noted earlier in this report, entries are identified by a coding system. There were 19 entries coded to “AB” which is an “accounting document”. 18 of the entries posted to account 55110010921000 (Unrealized Gains/Losses) and totaled $5,953.53 with the description “Valuation on 20221231”. The remaining entry totaling $ $16,012.48 was a corrective entry posted to account 50500010921000 with the description “Correct Reg Account for 804085”.

There were 230 carry forward entries coded as “CF” totaling $1,018,372.02 which is $50.85 less than the GP ending balance of $ 1,018,422.87 as discussed previously in this section.

SAP Code “CO” which is described as “CO Posting” consisted of 2,047 entries that totaled $283,926.78 and posted to various accounts all beginning with an 8XXXXX prefix. Entries consisted of descriptions such as treasury transactions, HR, legal, shared costs with company 3070. 16 entries entitled “AUD_SAP AUD SAP Companies” and totaled $28,890.17. Other entries were described as business development, customer care service, communications, compliance, corporate IT, "Director fee and Ins SAP co", environmental compliance, 62 entries entitled Executive or "Executive Service" or "Executive Offices" that totaled $10,399.64. Furthermore $4,921.09 was booked to various accounts as investor relations, 44 entries totaling $161,267.25 labeled as "Miscellaneous General" or "SAP Misc Cost SAP Companies", 93 entries entitled "Ops General" or "Ops General Service" totaling $13,393.09, 30 payroll entries totaling $1,848.17, 121 entries described as "Regulatory" or "Regulatory Compliance" that total $4,618.91, 21 entries labeled as "TOT Rewards" summing to $4,126.47, and 4 entries "Energy Procurement Office Supplies" totaling $10,877.71.

There were 253 entries coded to "KR" which translates to a vendor invoice and totaled $149,965.10. Entries were posted to various 500XX accounts with limited further descriptions such as legal, finance, procurement, engineering, HR, IT or Corporate IT, and "Facilities Utilities". Audit requested supporting documentation for 3 "KR" entries posted to SAP account 50140010921000 (Comm Exp-Telephone) totaling $54,321.37. All three invoices were for Verizon Wireless and in total summed to $181,071.22 which also showed as past due. The GSE portion was 30% of each individual invoice which include standard phone charges.

There was only 1 entry coded to "SA" which is a "G/L Document" and was a credit entry of $55,291.00. This amount appears to correspond to another entry coded to "WE" or "Goods Receipt" which Audit followed up with the Company for further information. The Company clarified this as a charge from Lebanon Ford for fleet repair and maintenance.

Audit also found there were 33 entries coded as "WA" or "Goods Issue" and totaled 9,907.51 and were only posted to account 50040010921000 (Materials and Supplies). There were also 52 entries coded to "WE" as discussed above is Goods Receipt" and totaled $82,189.93. There were 5 entries labeled as "WF" or "WFS Integration" that totaled $1,264.44 and all posted to account 80000010921000. Lastly, there were 434 entries coded to "WI" which translates to "Inventory Document" and totaled the largest amount of $803,038.67. All entries posted to account 50049510921000.

<u>Account #922 Administrative Expenses Transferred-Credit $(8,002,460)</u> per the FERC Form 1 does not agrees with the filing RR-2.10 which reflects $(8,501,412), a variance of $498,952. The SAP general ledger agrees with the filing. The Company indicated that the variance was "*due to the reversal of an entry to correct an unsettled WBS charge impacting regulatory net income.*" **Audit Issue #1 and Audit Issue #28**

The amount represents a <u>31% decrease</u> over the 12/31/2021 FERC Form 1 balance. Eleven SAP general ledger accounts make up the year-end balance of $(8,501,411.50):

50000010922000	Salaries and Wages	$ (283,886.41)
50400010922000	AllocCorp Cap Leg	$ 1,727.87
50500010922000	Other Operating Exp	$ -
50510010922000	Cost Alloc to Cap	$ (8,053,384.33)
80000010922000	Lbr Alloc	$ 2,373.00
80300010922000	Assess Lbr	$ (109,749.16)
80302010922000	Assess Material	$ 375.78
80304010922000	Assess Other	$ (64,327.20)
80305010922000	Assess Fleet - Asses	$ 22.02
80308010922000	Assess Meals	$ 532.59
80308510922000	Assess Travel	$ 4,904.34
		$ (8,501,411.50)

Please see the *Payroll* and *Allocation* sections of this report for a detail review of payroll and allocated labor.

Account #923 Outside Services Employed $2,381,415 per the FERC Form 1 reflects a decrease of 22% from the 12/31/21 year. The FERC Form 1 balance agree to filing schedule RR-2 and to the following SAP general ledger accounts:

50000010923000	Salaries and Wages	$ 8,439.80
50030010923000	Outside Svs	$ (171,988.65)
50034010923000	AllocCorp OutSvs Leg	$ 525,272.94
50240010923000	Legal Expenses	$ 27,132.20
50252010923000	Prof Svs-Acct/Audit	$ (25,583.57)
50254010923000	Prof Svs-Other	$ 488,549.77
50500010923000	Other Operating Exp	$ 11,593.84
50520010923000	AllocCorp NonLbr Leg	$ 784,967.28
50521010923000	AllocReg NonLbr Leg	$ 648,862.73
80000010923000	Lbr Alloc	$ 183.15
80303010923000	Assess Services	$ 1,397.03
85303010923000	As Serv-Intrc	$ 82,588.38
		$ 2,381,414.90

Although the FERC Form 1 amount agrees to the filing and the ending SAP general ledger balance, there was a $4,133.98 difference between the ending GP general ledger balance as of 9/30/22 and the SAP starting balance as of 9/30/22. **Audit Issue #1** The difference was related to a mapping issue where former GP account 8830-2-9825-69-5200-9230 was mapped to SAP account 50254010999999 instead of one of the 923 SAP accounts listed above.

Audit reviewed the GP general ledger and noted the following in accounts 8830-2-XXXX-69-5200-9230 Outside Services, which had a total of 17 accounts summing to $2,213,497.99 as of 9/30/22:

Outside Services Other - Account 9230 $340,835.44

8830-2-9800-69-5200-9230	$ 28,620.54
8830-2-9810-69-5200-9230	$ 30,139.79
8830-2-9812-69-5200-9230	$ 553.15
8830-2-9815-69-5200-9230	$ 21,140.23
8830-2-9820-69-5200-9230	$ 137,951.24
8830-2-9823-69-5200-9230	$ 56,546.46
8830-2-9830-69-5200-9230	$ 8,950.00
8830-2-9850-69-5200-9230	$ 3,401.53
8830-2-9854-69-5200-9230	$ 53,532.50
Subtotal of Accounts 9230	$ 340,835.44

Entries included monthly non labor accruals and reversals, tax and audit fee accruals. Amortization of prepaid expenses, legal fees and legal accruals. There were 106 invoices from vendors in this subaccount. Audit requested information for the 2 highest invoices from this subaccount totaling $42,500 from CMG Consulting, LLC and Pastori Krans PLLC totaling $17,637.70. The invoice from CMG Consulting LLC was the last payment toward the Liberty Utilities Grid Modification plan for the Bellow Falls area. The invoice was dated 2/18/22 and noted that there was "Delivery of final NWS reports and no travel or incidental charges" were on the invoice. The invoice from Pastori Krans was legal fees associated with case Liberty vs. Clearway Industries. The invoice was for 65.80 hours' worth of time and small copies fees for the month of Mach 2022.

Administrative Allocations Accounts 9211, 9232, 9234, 9235, 9236, 9237, 9238

8830-2-0000-69-5200-9231	Outside services LU HO Allocations	$	29,522.15
8830-2-0000-69-5200-9232	Outside services APUC HO Allocations	$	409,780.78
8830-2-0000-69-5200-9234	LABS NonLabour Allocations	$	174,917.82
8830-2-0000-69-5200-9235	LABS Corporate Service non-labour allocation	$	386,901.89
8830-2-0000-69-5200-9236	LABS US Bus admin alloc	$	72,782.48
8830-2-0000-69-5200-9237	LABS US Corp admin alloc	$	148,361.45
8830-2-9821-69-5200-9237	LABS US Corp Admin Allocations	$	2,003.64
8830-2-0000-69-5200-9238	LU Corp US Admin alloc	$	181,598.01
		$	1,405,868.22

All accounts included monthly indirect allocations and reversals. Please see the *Allocation* section of this report for additional information on corporate allocations.

East Region Outside Services Account 9239 $466,794.33

8830-2-0000-69-5200-9239	$ 443,656.40
8830-2-9810-69-5200-9239	$ 16,727.32
8830-2-9820-69-5200-9239	$ 14.37
8830-2-9865-69-5200-9239	$ 6,396.24
	$ 466,794.33

Account 8830-2-0000-69-5200-9239 (LU Region Admin Allocation) included indirect allocations and reversals. See the *Allocation* section of this report for a review of corporate allocations. There was only 1 invoice posted to account 8830-2-9865-69-5200-9239 (East Region Outside Services - Customer Service) totaling $97.11 for the Better Business Bureau of New Hampshire.

Audit also reviewed the SAP general ledger and notes the following in relation to the coding system identified in Account 921. There were 102 carry forward transactions summing to $2,218,800.40 however there were 3 transactions dated after the transition date of 9/30/22 totaling ($3,469.03) and dated 10/31/21. The Company clarified that the "*$(3,469.03) of CF charges dated 10/31/2022 were the reversals of accruals booked on 9/30/2022 in the Great Plains system which needed to be reversed manually in SAP in October. SAP automatically processes reversing entries on the first day of the following month, identical to the process in GP, however this process could not be done in SAP in October since the originating entry was posted in GP, not in SAP. These transactions would not have caused a variance between the GP general ledger and the SAP general ledger"* (at year-end). The carry forward charges 1/1/22 – 9/30/22 total $2,222,269.43 and as noted earlier differ than the ending GP balance of 2,213,497.99.

Entries designated with "CO" or "CO Posting" consisted of 681 entries totaling $83,985.41 and included memos for intercompany capital, investor relations, environmental compliance, talent acquisition, procurement services, insurance and HR services. Invoices with the "KR" designation for vendor invoices totaled $128,131.02 with some invoices designated as facilities, procurement, finance, "Government Affairs" and legal. Audit requested information for the 2 highest invoices totaling $31,448.75 and $19,446.45 only identified as "Regulatory". The Company provided the 2 invoices from Guidehouse summing to $50,895.20 for surveying and evaluation reports. The Company indicated both invoices were "*transferred to Battery Storage deferral account*" and therefore should be excluded from expense account 923. **Audit Issue #22**

There were 54 entries totaling ($125,190.96) designated as "SA" or "G/L Account Document" and included time sheet conversions, tax and audit fee accruals and reversals, and reclassifications. Only 1 entry was coded to "WE" or Goods Receipt for $600 and was further identified as "Rates & Regulatory-Outside Services". Additionally, there was only 1 entry coded to "WF" or WFS Integration summing to $183.15 and identified as "Electric Meter Srvs-Outside Services-Sal".

There were 5 entries coded to "ZA" or "Accrual Document" that totaled $74,305.88 and were all dated 12/31/2022. The entries were further identified as E&Y Audit Accrual, AP accrual and legal accrual.

Account #924 Property Insurance $1,589,317 per the FERC Form 1 demonstrates an increase of 1% over the prior year. The filing schedule RR-2.10 agrees with the FERC Form 1 which was verified to the SAP year-end balances reflected in the schedule.

50101010924000	Property Insurance	$1,589,024
85311410924000	As Prop Ins-Intrc	$ 293
		$1,589,317

General ledger detail also shows account 80111410924000 totaling $5,337. These entries were mapped incorrectly and reclassified to FERC account 242.

Schedule RR-2.10 reflects $1,500,000 pro forma adjustment. The $1,500,000 amount, per the general ledger, is debited $125,000 monthly, and is a source of funding for the major storms through credits to account 24140010254000, Other Regulatory Liabilities. The liability account is discussed in detail in the Utility's Storm Fund audit reports. The 2022 Storm Cost audit report, in docket DE 23-035, was issued on August 17, 2023.

Account #925 Injuries and Damages $927,599 per the FERC Form 1 reflects an increase over the prior period expense total $800,546, or 16%. The filing schedule RR-2.10 agrees with the FERC Form 1 balance. Schedule RR-3.9 shows the policies running from mid-2021 through mid-2022 total $1,052,198. The Schedule also shows the policies running from mid-2022 through mid-2023 sum to $919,284.

50030010925000	Outside Svs	$	1,500.00
50105010925000	Inj & Damages Insrce	$	926,099.02
		$	927,599.02

Two additional 925 accounts, totaling $8,263.31 are included in the general ledger but not the FERC Form 1.

50500010925000	Other Operating Expense	$ 0
80111810925000	OH Injuries & Damage	$8,263

The three entries in the Other Operating Expense account were reclassifications to the correct regulatory account, netting to zero. The OH Injuries & Damage total of $8,263 was mapped incorrectly and was reclassified to account 242. **Audit Issue #1**

Expenses in the Injury & Damages account included monthly amortization of prepayments and a payment to AEGIS.

Account #926 Employee Pensions and Benefits $3,697,502 per the FERC Form 1 is a reduction from the prior period of 22%. The account balances within the filing schedule RR-2.10 sum to $4,053,502, or $356,000 higher than the FERC Form 1. The general ledger shows a total of $3,720,678, or $23,176 higher than the FERC From 1. In response to a request for clarification of the variances, the Company noted that the variance "*is due to a correction for pre-cap meter overheads which were double booked.*" (see also $498,952 variance in account 922). The Company further noted that *The Company, along with our external auditors, determined to not reflect these adjustments in the FERC Form 1 to align with previously presented financial information in the APUC Form 10-K Annual Report and Granite State Electric standalone financial statements. The adjustments were correctly reflected in the Revenue Requirement."* Audit informed the Department of Energy staff to this and Data Request #11-14 was issued on October 5, 2023. Refer to **Audit Issue #1 and Audit Issue #28**

Extensive data requests were issued and answered regarding the pensions and benefits.

17010010926000	LTRA Pen&PostEmp Ben	$ -
50014010926000	Opt Out Cr	$ 6,963.19
50015010926000	Medicare/Healthcare	$ 1,499,628.24
50016010926000	RRSP/DPSP/401K	$ 1,287,679.75
50017010926000	Group/Emp Ben	$ (299,212.27)
50023010926000	StkPurPlns Emp Cntr	$ 20,423.82
50027010926000	Car Allowance	$ 249.23
57801010926000	OPEB Non-Srv Cst	$ 847,595.00
57802010926000	Pension Nn-Srv Costs	$ 198,075.04
70211010926000	BS Ops OH Benefit	$ (180,350.62)
70211710926000	BS OH PenOPEB Nonser	$ 86,197.16
80111010926000	OH Benefits	$ 17,353.50
80111310926000	OH Pension/OPEB	$ 5,823.05
85311010926000	As OH BenIntrc	$ 229,617.97
85311310926000	As Pnsn/OPEB-Intrc	$ 635.39
		$ 3,720,678.45

Please see the *Payroll* and *Allocation* sections of this report for additional information.

Account #928 Regulatory Commission Expenses $643,455 per FERC Form 1 is an increase over the 2021 balance of 18%. The general ledger account activity for January through September 2022 was noted in account 8830-2-9830-69-5610-9280, Regulatory Commission Expense. At conversion, the activity was rolled into SAP account 3071-50506010928000 Reg Commissions Exp.

Audit reviewed the PUC fiscal year assessments for 2022 (July 2021 through June 2022) and 2023 (July 2022 through June 2023):

	Electric	IESR	
2022 Quarter 3	$136,877	$ 41,366	
2022 Quarter 4	$136,877	$ 41,366	
2023 Quarter 1	$ 99,723	$ 28,916	
2023 Quarter 2	$128,820	$ 37,709	
	$502,297	$149,357	$651,654 combined

The IESR is the imputed energy suppliers' revenue. The $651,654 is reflective of the net assessments paid after a credit for overcollection from the prior year is applied in Quarter 1.

Audit reviewed the account activity in both the Great Plains system and the SAP. Monthly accruals were noted. The difference between the amount noted on the FERC Form 1 and the assessment amount is $8,199. Audit verified the difference to two specific journal entries:

February 28, 2022	$ 1,800.00
WBS element 1016710599(Strategy Svc)	
December 31, 2022 reclass PUC Assess to Default Srv	$(10,000.00)

The entries were offset to the following accounts:

10928000 Regulatory Commission Expenses	$1,800	
8830-2-9868-69-7450-4264 Political Contributions	$ 600	
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$1,800
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$ 600

The $1,800 membership investment, strategic plan, was part of a total Business and Industry Association (BIA) membership fee of $2,400 and appeared to have been incorrectly posted to the Regulatory account. In response to the draft audit report, the Company clarified that "*the total Business & Industry Association New Hampshire (BIA) membership dues were $8,000, and the table below provides Granite State Electric's share of the costs. The lobbying portion of the dues ($600) was correctly charged to political contributions. The $1,800 membership dues portion was incorrectly charged to regulatory commission expenses and should have been charged to dues and membership. The Company will make this adjustment in the next update of the revenue requirement model in this proceeding*." **AUDIT ISSUE #23**

	Total	GSE	EN
Dues	$ 6,000	$ 1,800	$ 4,200
Lobbying 25%	$ 2,000	$ 600	$ 1,400
Total Dues	$ 8,000	$ 2,400	$ 5,600

10142001 (Cust A/R- Undr Collect-Default-O/U)	$10,000	
10928000 (Regulatory Commission Expenses)		$10,000

The Revenue Requirement schedule RR-3.7, however, reflects:

DOE Assessment	$628,226
Recovered through Energy Service Rate	$ (10,000)
Total DOE Assessment in Distribution Base Rates	$618,226

Audit notes that a variance between the payments reflected in the FERC Form 1 and in the general ledger are a combination of 2 quarters from 2 different fiscal years (or calendar year) as opposed to the amount listed in Revenue Requirement schedule RR - 3.7 which is reflective of one full fiscal year 2024 (July 2023 through June 2024).

	Electric	IESR
2023 Quarter 1	$50,482	$ 28,916
2023 Quarter 2	$136,877	$ 37,709
2024 Quarter 3	$ 99,723	$ 37,709
2024 Quarter 4	$128,820	$ 37,709
	$502,297	$150,834

<u>Account #930.2 Miscellaneous General Expenses $(115,412)</u> per the FERC Form 1 reflects a reduction from the prior year $61,330 expense total. Audit verified the total to the filing Schedule RR-2-10.

The general ledger activity January through September was noted in Great Plains account

8830-2-0000-69-5615-9302 Miscellaneous General Expenses	$ 477.75
8830-2-9810-69-5615-9302 Miscellaneous General Expenses	$ 952.87
8830-2-9815-69-5615-9302 Miscellaneous General Expenses	$ 1,030.48
8830-2-9825-69-5615-9302 Miscellaneous General Expenses	$ 96,329.65
8830-2-9851-69-5615-9302 Miscellaneous General Expenses	$ 852.56
8830-2-9853-69-5615-9302 Miscellaneous General Expenses	$ 1,806.52
8830-2-9860-69-5615-9302 Miscellaneous General Expenses	$ 214.00
8830-2-9860-69-5615-9302 Miscellaneous General Expenses	$ 8,996.70
Account 930.2 Miscellaneous General Expenses a/o 9/30/2022	$110,660.53

The total of the Great Plains 930.2 accounts at 9/30/2022 was incorporated into the SAP Other Operating Exp account 3071-50500010930200. At year-end 12/2022, there were 3 SAP accounts for Miscellaneous General Expenses:

3071-50030010930200 Outside Services	$ 4,040.00
3071-50500010930200 Other Operating Exp	$(119,825.51)
3071-80000010930200 Lbr Alloc	$ 373.14
Account 930.2 a/o 12/31/2022	$(115,412.37)

Audit reviewed the activity in account 8830-2-9825-69-5615-9302 and noted 30 journal entries. All entries indicated a description of Job 8830-9825-COVID19. Nine of the entries related to Enterprise Holdings, Inc. d/b/a EAN Services and Enterprise Rent A Car. The sum of the car rentals is $89,975.21. Audit requested clarification of the job and a listing of the employees to whom the rentals were assigned. Audit further requested all jobs and related accounts associated with job 8830-xxxx-COVID19. The Company noted the following:

> "*The vehicles were rented for general use by field employees who typically worked as a team in one vehicle, thus allowing safe work conditions. The vehicles were not assigned to any one employee and consisted of a variety of vehicle types including pickup trucks, SUVs and passenger vehicles. The selected invoices covered vehicle rental periods from 11/19/2021 through 5/2/2022. The jobs established to track costs related to COVID-19 were charged to account 930.2 with labor for one job charged to account 920. The total costs by job and account are shown below:*"

COVID Job	Total Charges	GP GL Account	Total Charges
8830-9810-COVID19	$ 3,503.66	8830-2-9810-69-5615-9302	$ 3,503.66
8830-9815-COVID19	$ 59,013.76	8830-2-9815-69-5615-9302	$ 59,013.76
8830-9825-COVID19	$ 156,245.46	8830-2-9825-69-5615-9302	$ 156,245.46
8830-9830-COVID19	$ 77.70	8830-2-9830-69-5615-9302	$ 77.70
8830-9835-COVID19	$ 2,030.75	8830-2-9835-69-5615-9302	$ 2,030.75
8830-9840-COVID19	$ 25.91	8830-2-9840-69-5615-9302	$ 25.91
8830-9853-COVID19	$ 13,225.78	8830-2-9853-69-5615-9302	$ 13,225.78
8830-9860-COVID19	$ 214.00	8830-2-9860-69-5615-9302	$ 214.00
8830-9865-COVID19	$ 13,323.06	8830-2-9865-69-5615-9302	$ 13,323.06
8830-9851-COVID19	$ 156,749.46	8830-2-9851-69-5010-9200	$ 34,201.82
		8830-2-9851-69-5615-9302	$ 17,923.18
		8830-2-9852-69-5615-9302	$ 104,624.46
Grand Total	$ 404,409.54	Grand Total	$ 404,409.54

Because the COVID-19 pandemic has subsided, Audit recommends that all of these charges be considered non-recurring, and some, according to the Company information, are outside of the test year, although they did not indicate specifically which ones. **Audit Issue #18**

Among the activity in the SAP 3071-50500010930200, which resulted in the $(119,825.51) balance, were several corrections and reclassifications. Specifically:

9 entries-GSE missed A&G assessment correction 12.2022	$(93,907.22)
2 entries -Dec LUSC RCL	$(161,748.71)
9 entries - NH Interest Correction	$(12,816.72)
4 entries -Reclass to correct Reg Acct	$ net to -0-

The offset to the $(93,907.22) and $(161,748.71) were identified by the Company to be debit to Construction Work in Progress account 50500010107000. The $(12,816.72) was debited to Intercompany Payable, account 20101010234000.

Account #931 Rents $205,469 per the FERC Form 1 shows an increase from the prior year of 7%. The total on the FERC Form 1 was comprised of the Great Plains system balances as of 9/30/2022, incorporated into the year-end balances in SAP:

8830-2-0000-69-6125-9310	Rental Expense – Intercompany	$132,786.40
8830-2-9823-69-5110-9310	Rent Expense	$ 7,552.75
8830-2-9830-69-5110-9310	Rent Expense	$ 9,382.58
8830-2-9840-69-5110-9310	Rent Expense	$ 1,985.54
Rent Expense as of 9/30/2022		$151,707.27

The Rental Expense-Intercompany account, was rolled into SAP 3071-50130010931000. The remaining three Great Plains accounts, summing to $18,920.87, were rolled into SAP account 3071-50300010931000. At year-end, the SAP accounts were:

3071-50130010931000 **Meals & Ent**	$132,786.40 RR-2.10
3071-50300010931000 Rental Expense	$ 71,284.90 RR-2.10, RR-3.8
3071-50304010931000 Lease Exp	$ 1,397.50 RR-2.10
3071-50500010931000 Other Operating Exp	$ -0-
Rent Expense at year-end 12/31/2022	**$205,468.80 agrees with FERC Form 1**

The Rental Expense $71,284.90 was noted on the Revenue requirement schedule RR-3.8 as:

Intercompany Rental Expense Granite State annual lease	$59,236	Londonderry Office
Other Rental Expense	$12,049	
	$71,285	

The Intercompany account, $132,786.40 represents GSE's portion of the Londonderry office rent and the Concord Training Center. Audit noted monthly payments of $4,936.00 in GP and SAP each representing the GSE portion of the Londonderry office lease. For the year, the total was $59,236. Concord Training Center monthly lease payments were $10,560.95 for January through April 2022 and were $10,206.12 during the months of May through December 2022. Lease/rental payments are allocated between Granite State Electric and EnergyNorth.

Liberty and Ciborowski Associates, LLC have lease agreements for 2 properties: 2,150 square feet at 116 North Main Street, Concord (through 11/30/2026); and 1,660 square feet at 114 North Main Street, Concord, amended in 2019 to include an additional 645 square feet at 114 North Main Street. The lease at 114 North Main Street was extended until 11/30/2026, but the portion of the lease relating to the 645 square feet was not extended, and thus expired 11/30/2021. The amended leases were executed 12/30/2021. Express combined monthly rental was noted to be:

Per Amended Lease Agreement		Audit calculated	
Lease Period	Rent	Calendar Year	
12/1/2021 through 11/30/2022	$13,550.00 per month	$163,006.50	2022
12/1/2022 through 11/30/2023	$13,956.50 per month	$167,896.70	2023
12/1/2023 through 11/30/2024	$14,375.20 per month	$172,933.65	2024
12/1/2024 through 11/30/2025	$14,806.45 per month	$30,057.09	2025
12/1/2025 through 11/30/2026	$15,250.64 per month	n/a	

Lease/rental payments are allocated between Granite State Electric and EnergyNorth.

In response to DOE Staff Data Request #4-48, Liberty indicated that the original filing schedule RR-3.8 did not include all of the Rental Expenses. That response showed that RR-3.8 should have reflected:

Intercompany Rental-Londonderry building annual lease	$ 59,236
Intercompany Rental-Concord Training Center annual lease	$123,893
Facility Lease E-Point for 130 Main St. Salem	$ 26,125
Facility Lease 116 N Main St. Concord	$ 854
Filing per DOE DR 4-48	**$210,108**

The response reflects a change from the original RR-2.10 **$ 4,639 The DR 4-48 does not agree with the FERC Form 1. Audit Issue #24**

Account 935, Maintenance of General Plant $7,320

The FERC Form 1 reflects a total of $7,320 while the SAP general ledger as reflected on the filing schedule RR-2.10 shows a total of $7,322.16. The $2 variance is due to rounding and was not reviewed further. At the end of calendar year 2021, there was $-0- expense noted for account 935.

Audit reviewed the 2022 activity, and noted monthly entries supporting specific facilities in Charlestown, Lebanon, Londonderry, and Salem. Timesheet conversions and p-card expenses comprised the total. By location, Audit noted maintenance expenses for:

Charlestown	$ 175.00
Lebanon	$ 676.29
Londonderry	$6,270.91
Salem	$ 199.96
Total	$7,322.16

Due to time constraints, Audit was unable to test the $6,270.91maintenance total to determine if any part of that sum should have been allocated to EnergyNorth.

Corporate Allocations

Corporate expenses are allocated to GSE either directly or indirectly on a monthly basis. Audit requested all corporate billings for the month of November. GSE provided Audit with the following billings and supporting documentation:

- Direct Billing Manual LUC
- Direct Billing Manual LABS
- Direct Billing Auto-settle LUC/LABS combined
- Direct Billing Manual LUSC
- Direct Billing Auto-settle LUSC
- Indirect Billing Auto-settle LUSC combined
- Indirect Billing Auto-settle LUC combined
- Indirect Billing Auto-settle LABS combined

Direct Billing Manual LUC

Liberty Utilities Canada issued an invoice to GSE on 11/25/22 for the November 22 Direct Billing in the amount of $2,380. An Excel spreadsheet was provided to Audit as support for the invoiced amount. The spreadsheet contained expenses from Company Code 1048 and noted the customer as 2100EAST, 2100ENORTH and 2100GSTATES. Each line item noted if it was labor, outside services (with vendor names), benefits, etc. As LUC is a Canadian company, the invoices amounts are in Canadian Dollar with a conversion to USD.

The $2,380 charged booked to GSE was noted to be outside services for Granite State Regulatory Rate Case. As the invoice was noted to be for GSE, there was no 70/30 split with ENG.

Direct Billing Manual LABS

Liberty Utilities Canada issued an invoice to GSE on 11/25/22 for the November 22 Direct Billing in the amount of $2,405. The same Excel spreadsheet was provided to support the November LABS billing as the LUC billing. The spreadsheet contained the detail noted above.

There are two entries, $191 and $2,214, that were charged to GSE. The spreadsheet notes they are for outside services for “EH&S for Granite State”. As the expenses were for GSE only, they were not allocated 70/30 with ENG.

Direct Billing Auto-settle LUC/LABS combined

The direct billing auto-settle LUC/LABS totaled $126,646 for the month of November. As these charges are auto-settle, they are booked to GSE general ledger through an automated SAP settlement system. Due to this, there is no invoice provided to the Company.

Supporting documentation provided was an Excel spreadsheet containing a total of $1,237,88 in expenses from Company 1048. The spreadsheet contained several tabs including raw data, billing summary, pivot of the billing summary, a pivot for the NH changes and the procedures on processing direct billings.

Audit verified the raw data tab to the pivot billing tab. The pivot billing tab showed expenses of $126,645.55 for GSE. Audit then verified the GSE total to the NH Pivot without exception. The NH pivot provided the GL account, noted if it was outside service, labor, benefits, etc. Vendor names were also included for outside services. These expenses were booked fully to GSE’s general ledger.

Expenses charged to GSE were for outside services, labor allocations, overhead benefits, and overhead bonuses.

The pivot billing tab noted a total of $331,014 of expenses for Liberty NH. These charges were booked 30% to GSE and 70% to ENG.

Direct Billing Manual LUSC

Liberty Utilities Central Shared Services Co. provided an invoice to GSE on 11/25/2022 for November charges. The invoice totaled $46,227.55. GSE provided an Excel spreadsheet containing the billing data and a GSE billing summary.

The billing data showed the expenses booked to Company 3060 totaling $2,027,654. The data noted for which company the expense was, the type of expense, the Canadian Dollar amount and the USD amount, and other information. Audit verified the GSE total of $46,227 to the billing data.

The GSE billing summary tab provided a pivot table showing the GSE company, GL account number, type of expense and the total. The billing data also showed $61,588 being charged to Liberty NH in which the amount would be allocated 70/30.

Expenses charged to GSE were for travel expenses, meals & entertainment, labor allocations, and overhead expenses.

Direct Billing Auto-settle LUSC

The direct billing auto-settle for LUSC does not have an invoice. As previously noted, auto-settlement automatically books the expense to the GL through the SAP settlement system.

The total billed to GSE was $49,441. The supporting Excel spreadsheet provided the same type of information as noted in the Auto-settle direct billing for LUC/LUSC combined.

Audit verified the raw data, to the billing pivot, to the NH billing summary to the NH pivot without exception. $2,632 of the total was for travel expense, meal & entertainment, miscellaneous deductions, seminars, tips, hotels associated with energy efficiency programs. The remaining expenses were for travel, meals & entertainment, fleet, overhead, other operating expenses and the majority being for labor.

The 3070 total was $(694,068) for labor allocation and labor offset. This total was allocated 30% to GSE and 70% to ENG.

Indirect Billing Auto-settle LUSC combined

The expenses billed to GSE through the auto-settle LUSC are allocated through the 4 factor percentage. The percent charged to GSE is noted in the very beginning of the audit report. A total of $221,466 was allocated to GSE for November. Expenses included labor and associated costs, property insurance, travel, fleet, materials, services, and other.

As these expenses are auto-settled not invoice was provided. Supporting documentation included an Excel spreadsheet which contained the SAP billing data, and several tabs breaking the data down into different regions which checks and balances.

The East Region tab shows $127,387 being allocated to GSE at 4.30%. The Libcorp tab shows a GSE total of $38,422 at 4.40%and LABS tab shows a total of $55,657 at 4.40%. The total of these three tabs is $221,466

The GSE summary tab totals all the expenses charged to GSE and the GSE summary pivot provides the detail total by account number .

Indirect Billing Auto-settle LUC combined

The expenses billed to GSE for the LUC Indirect billing total $98,603. Supporting documentation provided included an Excel spreadsheet with the GL details, LU allocations, GSE summary and GSE summary pivot among other detail.

These LU expenses are allocated to GSE using the 4 Factor Percentage of 4.4%. The GSE Summary tab ties to the GSE summary pivot showing $98,603 charged to GSE for labor, materials, fleet, meals, payroll taxes and overhead benefits.

Indirect Billing Auto-settle LABS combined

The billed to GSE for the auto-settle LABS billing totaled $81,699 for November 2022. As supporting documentation to the auto-settle charges, GSE Provided an Excel spreadsheet. The spreadsheet provides the SAP detail, SAP journal entry, LABS allocation, GSE Summary and GSE Pivot.

Through the supporting Excel spreadsheets provided, Audit was unable to verify any of the corporate billing charges to the GL. Audit was also unable to verify the amounts being charged to GSE were based on the 4 Factor Percentage. **Audit Issue #25**

Taxes - Federal Income Tax

On January 1, 2014, a Tax Sharing Agreement went into effect, executed by the Vice President of Finance (of Algonquin). The Company indicated the agreement has not changed. The agreement represents that the consolidated returns will be compiled, with the members providing to the Parent the equivalent tax payment as if the member had filed individually. The agreement Schedule A reflected a listing of 32 original members, of which Liberty Utilities (Granite State Electric) Corp was one. Each has a specific Employer Identification Number.

Audit requested copies the federal tax returns filed by Liberty Utilities (America) Co for the test year. Pro forma federal form 1120 tax returns for Granite State were provided for 2021. The federal tax return detail was provided on July 10, 2023. The 2021 Federal return was filed on October 17, 2022 by KPMG. The Company anticipates filing the 2022 Federal Income Tax return by mid-October 2023. The overall taxable income was a loss for Liberty Utilities (America) Co and Subs with an overpayment for $4,759,101 identified. The overpayment was credited to the 2022 estimated tax. The consolidated schedule 1120 page 1, statement 3 reflects the GSE portion as a taxable net income of $15,597,304 based on:

Gross sales	$ 107,899,134	agrees with general ledger and FERC
Cost of goods sold	$ (61,336,383)	
Interest Dividend Income	$ 482,430	agrees with general ledger and FERC
Gross Royalties	$ 99,482	
Other Income	$ 1,858,934	
Salaries and Wages	$ (12,409,961)	
Bad Debts	$ (299,852)	
Repairs and Maintenance	$ (5,010,654)	
Rents	$ (188,872)	
Taxes and Licenses	$ (5,583,305)	
Interest	$ (2,204,756)	
Depreciation	$ (10,348,073)	
Charitable Contributions	$ (8,570)	
Advertising	$ (252)	
Other Deductions	$ (2,647,992)	
Taxable Income	$ 15,597,304	

The overall net income per the general ledger and FERC for 2021 was $12,529,618.

Schedule M2, statement 145 reflects the following:

Balance at beginning of year	$ 21,053,843
Net income per books	$ 12,420,797
Balance at end of year	$33,474,640 unappropriated retained earnings per proforma

20021 GSE 1120 return.

Schedule L, statement 75 Beginning, and schedule 82 Ending balances, of the 2021 federal return summarized GSE:

	Beginning	Ending
Cash	$ 61,625	$ (2,074)
Trade Notes and A/R	$ 15,822,178	$ 18,097,418
Less Allowance for Bad Debt	$ (752,497)	$ (734,292)
Inventories	$ 2,538,074	$ 2,400,315
Other Current Assets (1)	$ 11,938,777	$ 11,297,024
Bldgs and Other Depreciable Assets	$233,773,511	$265,551,731
Less Accumulated Depreciation	$(41,980,892)	$(49,641,737)
Land	$ 1,500,000	$ $1,500,000
Less: Intangible Asset A/D	$ (1,596,554)	$ (1,666,669)
Other Assets	$ 7,498,514	$ 9,834,430
Total Assets	$231,995,844	$259,969,484
Accounts Payable	$ 19,647,297	$ 30,553,030
Other Current Liabilities (2)	$ 15,118,960	$ 24,009,258
Mtg, Bonds, Notes Payable >1yr	$ 31,977,817	$ 31,981,581
Other Liabilities	$ 48,644,470	$ 42,128,039
Common Stock	$ 82,024,903	$ 82,024,903
Additional Paid in Capital	$ 17,000,000	$ 17,000,000
Retained Earnings	$ (21,053,843)	$(33,474,640)
Adjustment to Shareholder Equity	$ (3,471,446)	$ (1,201,967)
Total Liabilities and Equity	$231,995,844	$259,969,484

(1) Other Current Assets were noted on statement 97 to include:

Prepaids	$ 1,401,770	$ 1,233,254
Current Regulatory Assets	$10,537,007	$11,011,159
Income Tax Receivable	0	($947,389)
Sub-total	$ 11,938,777	$11,297,024

(2) Other Current Liabilities were noted on statement 118 to include:

Accrued Liabilities	$ 9,803,286	$10,957,868
Current Portion of Other LTD	$ 1,181,318	$ 1,206,777
Current Portion Regulatory Liab	$ 3,995,431	$ 4,883,774
Accrued Interest	$ 325,292	$ 142,792
Current Tax Payable	$ (186,367)	$ 2,091,481
Other Current Liabilities	$ 0	$ 4,775,983
Operating Lease Liability	$ 0	$ 583
Sub-total	$15,118,960	$ 24,009,258

Audit verified that the reported GSE portions of the Liberty Utilities (America) Co federal tax return agrees with the pro-forma GSE stand-alone federal tax return. Certain items were verified to the general ledger of GSE, without exception.

The Company provided a copy of the Liberty Utilities (America) Co. & Subs statewide tax returns for the calendar year 2021. The 942-page document, prepared by KPMG, LLP Toronto, included state specific returns for Arizona, Arkansas, California, Georgia, Illinois, Iowa, Kansas, Massachusetts, Missouri, New Hampshire, New York, Oklahoma, and Texas. For Liberty Utilities (America) Co, the NH BT-Summary reflected a net overpayment for the tax year 12/2021 of $107,290 that was filed on November 15, 2012. The Company has not filed its 2022 NH BT-Summary and anticipates filing the return by Mid November 2023.

State Income Taxes

The 2021 Liberty Utilities (America) Co. & Subs information was provided on July 10, 2023. The BET was overpaid by $107,290, with the overpayment applied to the 2022-estimated tax. The overpayment was the result of:

The calculated BET	$ 358,597
Less estimated tax payments	$(230,000)
Less Tax Paid w/ Application Extension	$ (190,000)
Less carryover from prior tax period	$ (45,887)
Net overpayment	$(107,290)

The NH Business Profits Tax Return indicated that there is a net operating loss deduction (NOLD) to be carried forward in the amount of ($13,904,514), at the Liberty Utilities (America) Co level. Use of a portion of the NOLD resulted in a loss for the year. The net income noted on statement 3, $12,420,797 agrees with the federal return. Statement 11 reflects 29 other members included in the water's edge combined group.

General Ledger Accounts Associated with State and Federal Income Taxes

The Company has not filed 2022 State or Federal Income Taxes but provided Audit with the proformed tax worksheets and provisional tax entries compiled by the Tax Manager in Oakville.

The Accumulated Deferred Income Taxes account 190 did not have any activity during 2022 and had a zero balance, which agrees with the FERC Form 1.

The Accumulated Deferred Income Taxes-Other account 283 on the FERC Form 1 consisted of five accounts with three accounts not having any account activity and ended 2022 with a zero balance. The LTL Accumulated Deferred State Income Tax Account Utility Property Plant and Equipment ended 2022 with a $0.02 account balance.

17090010283000 LTRA Income Tax	$0
24090010283000 CPRL Income Taxes	$0
26090010283000 LTRL Income Taxes	$0
27200010283000 LTL Accum Def. Fed. Income Tax PPE	($17,743,668)
27210010283000 LTL Accum Def. State Income Tax PPE	$0.02
Total 283 Per Annual Report	($17,743,668)
24090010254000 CPRL Income Taxes	($268,243)
26090010254000 LTRL Income Taxes	($4,763,022)
Total 283 and 254 accounts Per GL	($22,774,932
Filing Schedule RR-4.5 post close true up of state EADIT for rate case	($7,471)
Total ADIT Per filing schedule RR-4.5	($22,782,403)

Net GSE Accumulated Deferred Income Tax was verified to FERC Form 1 and the filing schedules RR-4.5. The Company summarized the purpose of the 283 and 254 accounts that "*includes both the excess deferred taxes as well as a tax gross-up related to the tax benefit of returning the excess ADIT to our customers through future rates. The gross-up represents future taxes and is offset by a deferred tax asset that has been recorded in the 283 account. The gross-up portion of the EADIT and the DTA net to zero on the balance sheet. For the rate case, we have excluded the gross-up from the EADIT balance and the corresponding deferred tax asset.*"

The 283 and 254 accounts on the GL summed to ($22,774,932) and the filing summed to ($22,782,403). This is a ($7,471) difference caused by a post close true up to state EADIT for the rate case and the related deferred tax asset.

Activity within the accounts was reviewed and verified to tax worksheets prepared by the Oakville Tax Manager. Offsetting entries were noted to Deferred State Income Tax Expense, Deferred Federal Income Tax Expense, and OCI FASB 158 Pensions account 36206010219000.

59001010409100 State Income Tax expense	$873,455	FERC Form 1 acct 409.1 line 16
59000010409100 Federal Income Tax Expense	$2,238,709	FERC Form1 acct 409.1 line 15
Total 409 accounts per GL	$3,112,164	
Total per Filing RR-2.13	$2,651,781	
Filing and 409 GL Variance	$460,383	

The 409 current income tax expense accounts summed to $3,112,164 while the filing schedule RR-2.13 totaled $2,651,781. This is a $460,383 difference that the Company indicated was properly excluded from the filing that were due to regulatory adjustments that were the result of a ($5,624) Business Enterprise Tax true up credit adjustment and a $466,007 NH Business Profits Tax rate adjustment.

The 409 federal and state income tax expense accounts Great Plains September 30, 2022 ending GL balance and the beginning balance for SAP were different from one another. The Company indicated the September 2022 SAP tax entries were booked to the incorrect account during the GP to SAP conversion which caused the identified differences below. The correcting entries were done in December and are summarized below.

As of September 30, 2022			
8830-2-0000-80-8710-4090 Federal Income Tax expense per **GP**		$2,702,729	
59000010409100 Federal Income Tax expense per **SAP**		$1,427,325	
Federal 409 acct Difference		$1,275,404	

December 2022 Correcting Entry			
59000010409100	Federal Income Tax Expense	$1,275,404	
59000010920000	Administrative and General Salaries		$1,275,404

8830-2-0000-80-8720-4090 State Income Tax Expense per **GP**	$1,058,582
59001010409100 State Income Tax Expense Per **SAP**	$559,042
State 409 acct Difference	$499,540

December 2022 Correcting Entry		
59001010409100 State Income Tax Expense	$499,540	
59001010920000 Administrative and General Salaries		$499,540

5902101040100 Def FIT Expense	$1,250,385	ok to FERC Form 1 acct 410
59023010410300 Deferred Amort. Excess ADIT	($190,014)	
Total Per GL	$1,054,365	
Total Per Filing RR-2.13	$1,667,219	
Filing and GL difference	($612,855)	

The 410 deferred income tax expenses totaled $1,054,365 while the filing schedule RR-2.13 totaled $1,667,219. This ($612,385) difference is the result of operating income before tax adjustment differences between what was booked to the GL. For Regulatory purposes the operating before income tax adjustments were $16,763,546 for the test year and on the GL, it was $15,915,399. This is a ($848,147) difference. The Company provided the journal entries that were to capitalize the physical inventory write off, correct the over accrual of capital invoices that were paid in 2022, correct pre capitalized meter overheads that were double booked, and the reversal of an entry to correct the regulatory net income checklist item. Other differences include the Excess ADIT true up, AFUDC Amortization, State EADIT, and AFUDC Equity.

The 410 federal deferred income tax expense accounts Great Plains September 30, 2022 ending GL balance and the beginning balance for SAP were different from one another.

As of September 30, 2022	
8830-2-0000-80-8760-4104 Deferred FIT per **GP**	$8,104
59021010410000 FDIT expense per **SAP**	$5,315
410 account Difference	$2,789

December 2022 correcting Entry

8830-2-0000-80-8760-4104 Deferred FIT	$2,789	
59001010920000 Administrative and General Salaries		$2,789

Prepaid Property Taxes

14081010165000 Prepaid Property Tax	$107,888
14090010165000 Other Prepaids	1,276,789
Total 165 Prepaids per SAP GL and FERC Form 1	$1,384,677
Prepayments RR-4 line 7	$1,915,251

The filing schedule RR-4 reflects total prepayments of $1,915,251 for 2022. The 165 prepaids account on the GL and FERC Form 1 summed to $1,384,677. This is a $530,574 difference that is a function of presentation/mapping of accounts. The 1402xx accounts are the three clearing accounts that will clear depending on timing. A specific example of this are payments made for purchase cards and expenses are matched against those as they are coded and approved through the purchase card system. A small rolling balance is expected based on the timing of when these payments are made. The $530,574 difference is made up of the following three GL accounts below.

140230 Billable Intercompany Clearing	$129,595
140240 Billable Clearing	$398,803
140250 Purchase Card Clearing	$2,176
Total	$530,574

Property Taxes

For the test year, the Company expensed $6,549,124. Refer to the filing schedule RR-2-11. Audit reviewed the second issue 2021 municipal property tax invoices for the 25 communities in which the Company has taxable assets, and both first and second issue invoices for 2022. Audit verified the reported expense and prepayment figures to the general ledger accounts below:

50011010408000 SS/CPP/Emp Pension	$457,573
50012010408000 Unemployment Insurance	$4,267
50013010408000 FICA Taxes	$237
50015010408000 Medicare Taxes	$125,786
80111210408000 Overhead Payroll Taxes	$4,620
85311210408000 As Payroll Tax-Intrc.	$28,632
50260010408000 Property Tax RR-3.6	$5,906,188
80111210408000 Overhead Payroll Taxes	$26,441
Total per filing schedule RR-2.11 and FERC Form 1	$6,549,124

80111210408000 Overhead Payroll Taxes	$4,620

See the *payroll section* of this report for a more detailed explanation for variances related to payroll/payroll taxes.

Audit requested and was provided with all municipal property tax invoices for the years 2021 and 2022, as well as the State of New Hampshire utility property tax invoices. The result of that review is demonstrated below, per Audit calculation that was done by multiplying the town mill rate by property valuation on the town property tax invoice:

½ of 2021 second issue municipal	$1,006,248	
Complete 2022 first issue municipal	$2,091,070	
½ of 2022 second issue municipal	$ 1,395,987	
Subtotal municipal	$4,668,924	
2022 State of NH Utility Property tax	$1,288,617	
Total property tax calculated expense	$5,781,922	$124,266 lower than GSE expensed on GL

The calculated property tax expense for the year is $124,266 lower than the $5,906,188 amount booked to the general ledger 408 property tax expense account. The reason for the $124,266 difference that Audit calculated, and the GL is due to timing differences and true up of municipal/state property tax expenses. The Company on filing schedule RR-3.6 calculated the property tax expense for 2022 to be $6,171,661 while the GL 408 account expensed amount is $5,906,188. The reason for the $265,473 difference in property tax bills vs. expense has to do with the difference between fiscal and calendar year property tax bills. The Company specially indicated, "*Towns that operate on a fiscal tax year will have bills paid in a different calendar year than 2022. (ex. Bill received in December 2021 would be for the period January–June 2022). For each of the following 6 months after the bill was received, 1/6 of that amount is moved from the 165 Prepaid Expense amount to the 408 Property tax expense account. The same process will occur for fiscal towns for the months of July–December for bills received in June. Bills received for fiscal towns in December 2022 would be related to expenses for the first 6 months of 2023, even though they were paid in 2023. Therefore, the $265,473 difference is related to property tax bills that will be expensed in 2023.*"

On June 8, 2023 the DE 23-037 property tax PTAM audit report was issued. The audit report reviewed both issuances of the 2022 municipal property tax bills that summed to $4,816,970. The report identified ($28,184) in municipal property tax adjustments that indicates GSE should recover $4,788,786 in 2022 municipal property tax expenses. The adjustments related to the $227 Town of Charlestown for including the State Education Tax, $28,194 adjustments to the Town of Walpole related to the reported filing vs the 2022 actual amounts on the property tax bill, and a $237 allowance based on a difference between the filing and actual tax obligation due to a lower parcel assessment in Windham. Based on a review of the RR-3.6 property tax filing schedule the Company will need to make the same ($28,184) adjustment plus an additional adjustment of ($66,074) related to Lebanon Parcels 157/1 and 157/2 that audit report indicates the assets were not placed into service and not considered used and useful. The net adjustments to the 2022 municipal installment payments are now $4,788,786 as was presented in the audit report. **Audit Issue #26**

The 2022 state utility tax expense on the filing was $1,288,617. Audit verified four quarterly DP-255 quarterly payments that were $309,897 estimated state utility taxes made in April 15 2022, June 15 2022, September 15, 2022, and December 15, 2022. The Company made a

$49,027 December 31, 2022 true up when the 2022 State Utility Tax bill was received The Company calculated the $4,883,044 property tax expense using both issuances of the 2022 municipal property tax bills. This is a $389,739 difference between the filing and the 408 GL expensed account. This is due to the Company calculating the tax expense a different way as discussed in subsequent paragraph.

The Company books property taxes to the prepaid account using a property tax schedule for 2021 and 2022 based on Towns' Fiscal and Calendar years. The monthly debit entry for Calendar Towns is $209,548 and $241,268 for Fiscal Towns for January 1-June 30, 2022. This is $450,816 per month for both entries The July 1, 2022-December 31,2022 monthly debit entries for Calendar Towns are $228,377 and for Fiscal Towns is $245,637. This is $474,014 per month for both entries The monthly schedule estimates are adjusted accordingly after receiving first half tax bills in May/June and November/December of a tax year. The amounts were reconciled in December 2022. The Company's Accounts Payable department determines whether a town is a Fiscal or Calendar town.

For towns that are on a calendar year basis, the latest property tax bill is used to record the property tax expense for the next 6 months (assuming the time covered on the invoice is 6 months. Towns on the fiscal year basis, the property tax expense is calculated by taking the balance of the prepaid property tax expense, calculating the actual months of prepaid taxes and the difference represents property tax expense for the month. The towns of Derry, Atkinson, Hanover, Londonderry, Salem, and NH DRA are on the Fiscal Year Calendar.

The recurring monthly entries are offset with credits to two accounts:

For January-June 2022:

Property Tax Expense 8830-2-9820-69-5680-4080	$450,816	
Tax Accrual-Municipal Property 8830-2-0000-20-2530-2364		$209,548
Prepaid Taxes-Mun-Property-Oper 8830-2-0000-10-1240-1653		$241,268

For July-December 2022:

Property Tax Expense 8830-2-9820-69-5680-4080	$474,014	
Tax Accrual-Municipal Property 8830-2-0000-20-2530-2364		$228,377
Prepaid Taxes-Mun-Property-Oper 8830-2-0000-10-1240-1653		$245,637

All entries in the Tax Accrual account netted to zero at year-end. The Prepaid Taxes account began the year with $1,137,713 and a year-end balance of $1,276,788.

Audit reviewed the general ledger activity and noted that actual payments made to specific municipalities are debited to the prepaid account, and credited to 8830-2-0000-20-2810-2606, Liberty Energy New Hampshire and after September 2022 to the Liberty Energy Intercompany Accounts Payable account 201010234000.

Adjustments to the prepaid account and accrual account were booked in June and December, based on actual payments made. The final entry in the Tax Accrual account was a debit of $1,012,332 that zeroed the account and was offset to the Prepaid Taxes account.

The Company indicated there were no abatements granted by towns during 2021 and 2022.

Penalties

Audit did not see any expenses related to tax penalties or late payments. The FERC Form 1 did reflect $1,500 in account 426.3, Penalties. In response to DoE data request 5-9 regarding $1,500 noted on Bates I-011, the Company indicated:

> "*The Penalties amount of $1,500.00 charged to account 426.3 in the test year was in payment of two separate Dig Safe violations - Notice of Probably Violation (NOPV) #2022070 for $500.00 and NOPV #2022071 for $1,000.00. The penalties were appropriately charged below the line to account 426.3 and, therefore, were not included in the proposed Revenue Requirement.*"

Audit agrees that the 426.3 account is below the line. There was not a Penalties account in Great Plains, but within SAP is account 3071-50511010426300, reflecting the $1,500.

Audit verified the two incidents to the website for the Enforcement Division of the NH Department of Energy Q2 2022 Non-gas details of violations. The incidents occurred in May in Windham and June in Salem. A review of all other 2022 quarterly reports show that Liberty was not involved in any other non-gas related incidents. Audit also reviewed the Enforcement website for all Liberty/Granite State related incidents since the prior rate case, with the following noted:

Liberty- Granite State Electric

Control #	Date	Municipality	Reporting Party	Operator	Conctractor	Finding	Penalty
2019050	5/21/2019	Lebanon	Liberty GSE	Liberty GSE	Pike Industries	Operator at fault	$ 500
2019069	6/7/2019	Salem	Liberty GSE	Liberty GSE	Busby Construction	Operator at fault	$ 500
						Total 2019	$ 1,000
No violations reported for Liberty Granite State Electric in 2020 or 2021							
22070	5/10/2022	Windham	Liberty GSE	Liberty GSE	American Excavation Corp	Operator at fault	$ 500
22071	6/14/2022	Salem	Liberty GSE	Liberty GSE	Continental Paving	Operator at fault	$ 1,000
						Total 2022	$ 1,500

Income Tax Receivable

Audit reviewed the GSE Account 14601010143000 Income Tax Receivable that indicated there was a ($1,014,482) year-end tax credit balance. The SAP account activity consisted of a ($159,301) November 2022 tax entry based on 2021 tax payments and a $344,428 December 2022 year-end tax entry. The Company indicated the account represents the state cumulative income taxes that GSE has incurred but not paid. GSE owes this amount to Liberty Utilities (Americas) Co. (Parent). Liberty Utilities (GSE) is a member of a consolidated state tax return filed by the parent organization. Audit reviewed a November 2022 ($159,301) entry that was a state tax true up from the tax provision to tax return for the 2021 tax year.

The December 2022 entry for $344,428 represent the quarterly tax payment based on 2022 activities. The ($1,014,482) December 31, 2022 balance is an accumulation of NH state taxes **payable** since the last rate case in 2019 on the stand-alone basis. Audit reviewed the offsetting account detail which is the NH Current State Income Tax expense account 59001010409100. The Company further indicated that GSE makes a true up entry every year after the prior year return is filed on November 15th of each year. The 2021 state return was filed on November 15, 2022 and the 2022 NH State return will be filed on November 15, 2023.

1/1/2022	(947,389)	
	806,362	BET Tax Credit
	(251,496)	Q1 tax provision - BPT tax estimate
	(307,547)	Q2 tax provision - BPT tax estimate
	(499,540)	Q3 tax provision - BPT tax estimate
	(159,301)	2021 Book to Return true up
	344,428	Q4 tax provision - BPT tax estimate
12/31/2022	(1,014,483)	

Audit Issue #1
General Ledger Settlement Set-up

Background

On October 1, 2022, Liberty converted from the legacy Great Plains accounting system and Cogsdale billing system to SAP. Part of the conversion to SAP was described as "*The job system in SAP is known as WBS elements (Work Breakdown Structure). These are used to record and track expenses to specific areas of the business: Capital, Intercompany, and Operations and Maintenance. The process that does this is called settlements. In this process, WBS activities are reflected in 7xxxxx and 8xxxxx natural GL accounts and allocated to be reflected in income statement or balance sheet accounts. Once the settlements are run, each WBS should be zero. When a WBS is not zero it means a transaction, while in the GL, did not "settle" where it needed to be reflected. This could be either a coding issue or a timing issue.*"

Issue

Audit noted that coding issues, which Liberty identified when compiling the FERC Form 1, resulted in accounts and/or transactions that appeared in one account in SAP, but were reflected in another account on the FERC Form 1. Audit requested clarification of when the reclassifications and/or "mapping issues" were corrected, and was told that the corrections were not reflected in the SAP system in 2022. Rather, "*throughout 2023, as these* [issues] *have been identified, we are correcting those through manual journal entries or updating the treatment of WBS in the system, as applicable*."

As a result, the 2022 FERC Form 1 does not actually agree with the general ledger <u>accounts</u> at the end of the test year, without the addition to or removal of the numerous "adjustments" which did not take place during the test year, or at the year-end closing of the financial records. In addition, the filing schedules, while reflecting the SAP accounts at year-end, do not literally reflect all of the accounts in the proper location.

Specifically, some (but unknown if all) variances from the FERC Form 1 to the SAP at year-end were identified by Audit to be:

FERC Account	FERC Form 1	SAP Year-end	Variance	
107	$ 15,266,206	$ 15,258,393	$ 7,813.00	
142	$ 29,736,312	$ 29,736,311.52	$ 0.48	Four additional #142 accounts =$18,298.72, in FERC Form 1 #920
146	$ -	$ 964,071,908.63	$ (964,071,908.63)	
163	$ -	$ 54,508.80	$ (54,508.80)	
182.3	$ 4,557,561	$ 5,813,867.39	$ (1,256,306.39)	
184	$ 1,052,518	$ 1,142,090.69	$ (89,572.69)	
186	$ -	$ 165,861.82	$ (165,861.82)	
234	$ (75,125,573)	$ (1,039,197,481.56)	$ 964,071,908.56	
242	$ (32,120,029)	$ (35,849,681.42)	$ 3,729,652.42	
254	$ (6,913,697)	$ (7,746,740.25)	$ 833,043.25	
50500010**440**000	$ -	$ (1,077,479.83)	$ 1,077,479.83	
24672010**593**000	$ -	$ 3,675,811.00	$ (3,675,811.00)	
5xxxxx10**920**000	$ 2,877,428	$ 2,618,648.73	$ 258,779.27	
5xxxxx10**921**000	$ 2,287,231	$ 2,313,715.26	$ (26,484.26)	
xxxxxx10**922**000	$ (8,002,460)	$ (8,501,411.50)	$ 498,951.50	
80111410**924**000	$ -	$ 5,337.34	$ (5,337.34)	
80111810**925**000	$ -	$ 8,263.31	$ (8,263.31)	
xxxxxx10**926**000	$ 3,697,502	$ 3,270,678.45	$ 426,823.55	

Liberty provided information reconciling the annual report to the SAP. Audit could not determine if the adjustments are correct, nor if they represent what the year-end SAP balances should be:

Regarding the $7,813 variance between the FERC Form 1 account #107, Construction Work in Progress, and the total of all SAP account 107 related accounts, the Company noted:

Office Supplies and Expenses	50211010921000	$ 14,040.00	Exclude from 921-Add to 107
CWIP-Ut Plt-FERCE	50500010107000	$ (5,264.43)	Add to 920-Exclude from 107
CWIP-Ut Plt-FERCE	70200010107000	$ (962.31)	Add to 920-Exclude from 107
		$ 7,813.26	

The four additional balance sheet account #142, Customer Accounts Receivable, SAP accounts are reported in the FERC Form 1 in the income statement account #920, Administrative and General Salaries. The accounts were noted to have been mapped to a balance sheet asset account, but were included on the FERC Form 1 in the income statement.

Regarding the $(964,071,908.63) variance between the FERC Form 1 account #146, Accounts Receivable from Associated Companies, and the SAP account 10146000, Intercompany Accounts Receivable, the amount is offset by the variance on account #234, Accounts Payable to Associated Companies. The Company confirmed that the Accounts Receivable from Associated Companies balance was netted with the Accounts Payable to Associated Companies.

Five balance sheet accounts relating to account #163, Stores Expense Undistributed, were also reflected in the FERC Form 1 income statement account #920, Administrative and General Salaries.

The $1,256,306.38 variance between the FERC Form 1 and SAP for balance sheet account #182.3, Other Regulatory Assets, was noted by the Company to be the identification of the following:

CRL Fuel and Commod Cost	24080010182300	$	(833,043.45)	Exclude from asset account 182.3-Add to liability account 254
Salaries and Wages	50000010182300	$	1,081.00	Exclude from balance sheet 182.3-Add to income statement 920
Outside Services	50030010182300	$	1,411.98	Exclude from balance sheet 182.3-Add to income statement 920
Outside Services	50030010182300	$	(53,144.70)	Exclude from balance sheet 182.3-Add to income statement 920
Outside Services	50030010182300	$	(37,141.25)	Exclude from balance sheet 182.3-Add to income statement 920
Other Operating Expense	50500010182300	$	(2,380.00)	Exclude from balance sheet 182.3-Add to income statement 920
LTRA R8 Case Cost	17120010186000	$	165,861.82	Add to balance sheet 182.3-Exclude from asset account 186
Cost Alloc to Cap	50510010922000	$	(316,613.20)	Add to balance sheet 182.3-Exclude from income statement account 922
Cost Alloc to Cap	50510010922000	$	(182,338.46)	Add to balance sheet 182.3-Exclude from income statement account 922
		$	(1,256,306.26)	

The $89,572.69 variance between the FERC Form 1 and SAP for balance sheet account #184, Clearing Accounts, was reportedly identification of certain balances or transactions that should have been excluded from the balance sheet account and included in the income statement account 920, Administrative and General Salaries:

Overtime	50001010184000	$	1,887.18	Exclude from 184-Add to 920
WBS St Lbr-Intrc	85400010184000	$	(32.80)	Exclude from 184-Add to 920
WBS ST OH Ben-Intrc	85411010184000	$	(25.29)	Exclude from 184-Add to 920
WBS ST OH PrlTx-Intr	85411210184000	$	(3.08)	Exclude from 184-Add to 920
WBS ST OH Pn/OPEB-In	85411310184000	$	(3.15)	Exclude from 184-Add to 920
WBS ST OH Prin-Intrc	85411410184000	$	(1.77)	Exclude from 184-Add to 920
Salaries and Wages	50000010184000	$	9,038.97	Exclude from 184-Add to 920
Outside Svs	50030010184000	$	1,722.70	Exclude from 184-Add to 920
Fleet-Fuel	50121010184000	$	20,300.03	Exclude from 184-Add to 920
Fleet-Repair/Main	50121010184000	$	41,361.89	Exclude from 184-Add to 920
Rental Expense	50300010184000	$	950.00	Exclude from 184-Add to 920
Other Operating Exp	50500010184000	$	(74,713.52)	Exclude from 184-Add to 920
BS Lbr Offset	70200010184000	$	(77,732.34)	Exclude from 184-Add to 920
BS Other Offset	70204010184000	$	100,350.11	Exclude from 184-Add to 920
BS Ops OH Benefit	70211010184000	$	(48,551.64)	Exclude from 184-Add to 920
BS OH Payroll Tax	70211210184000	$	(7,306.84)	Exclude from 184-Add to 920
BS OH Pension/OPEB	70211310184000	$	(7,470.08)	Exclude from 184-Add to 920
BS OH Prop Ins	70211410184000	$	(4,205.31)	Exclude from 184-Add to 920
BS Ops Vac Allocation	70211610184000	$	(11,403.32)	Exclude from 184-Add to 920
Lbr Allocation	80000010184000	$	106,666.98	Exclude from 184-Add to 920
OH Benefits	80111010184000	$	33,666.92	Exclude from 184-Add to 920
OH Payroll Tax	80111210184000	$	11,053.76	Exclude from 184-Add to 920
OH Pension/OPEB	80111310184000	$	11,300.70	Exclude from 184-Add to 920
OH Prop Ins	80111410184000	$	6,361.78	Exclude from 184-Add to 920
OH Vacation	80111610184000	$	17,250.90	Exclude from 184-Add to 920
OH Inj&Damage	80111810184000	$	9,854.31	Exclude from 184-Add to 920
OH Bonus	80111910184000	$	11,265.42	Exclude from 184-Add to 920
OH IT Cists	80114110184000	$	17,180.37	Exclude from 184-Add to 920
OH Rent	80114210184000	$	1,481.68	Exclude from 184-Add to 920
OH A&G N-Labr	80117010184000	$	24,471.14	Exclude from 184-Add to 920
WBS ST Serv-Intrc	85403010184000	$	(1,093.70)	Exclude from 184-Add to 920
WBS ST Other-Intrc	85404010184000	$	(42,471.65)	Exclude from 184-Add to 920
WBS ST Fleet-Intrc	84505010184000	$	(61,579.42)	Exclude from 184-Add to 920
		$	**89,570.93**	

Regarding the $165,861.82 variance between the FERC Form 1 account #186, Miscellaneous Deferred Debits, and the SAP account 17120010186000, LTRA R8 Case Cost, the amount is reflected on the FERC Form 1 within account #182.3, Other Regulatory Assets.

Regarding the $964,071,908.56 variance between the FERC Form 1 account #234, Accounts Payable to Associated Companies, and the SAP account #10234000, Intercompany Accounts Payable, the amount is offset by the variance on account #146, Accounts Receivable from

Associated Companies. The Company confirmed that the Accounts Payable from Associated Companies balance was netted with the Accounts Receivable to Associated Companies.

The $3,729,652.59 variance between the FERC Form 1 account #242, Miscellaneous Current and Accrued Liabilities, and the SAP 242 related accounts was noted by the Company to be:

Current REC Obg Non-reg	24672010593000	$ 3,675,811.00	Exclude from Income Statement account 593, add to balance sheet account 242
OH Benefits	80111010926000	$ 17,353.50	Exclude from Income Statement account 926, add to balance sheet account 242
OH Payroll Tax	80111210408000	$ 4,620.26	Exclude from Income Statement account 408, add to balance sheet account 242
OH Pension/OPEB	80111310926000	$ 5,823.05	Exclude from Income Statement account 926, add to balance sheet account 242
OH Prop Ins	80111410924000	$ 5,337.34	Exclude from Income Statement account 924, add to balance sheet account 242
OH Inj&Damage	80111810925000	$ 8,263.31	Exclude from Income Statement account 925, add to balance sheet account 242
OH A&G N-Labr	80117010921000	$ 12,444.13	Exclude from Income Statement account 921, add to balance sheet account 242
		$ 3,729,652.59	

The variance of $833,043.25 between the FERC Form 1 and the SAP for account #254, Other Regulatory Liabilities, was identified to be account 24080010182300, CRL Fuel&Commod Cost, which was mapped to account 182.3 but should have been within account 254. The $833,043.25 was reflected on the FERC Form 1 on the line for account 254.

The variance of $258,778.99 between the FERC Form 1 account #920, Administrative and General Salaries, and the actual SAP 920 related accounts was noted by the Company to be mis-mapped accounts between the balance sheet and the income statement:

Salaries and Wages	50000010140000	2,472.80	Exclude from account noted, included in account 920
Salaries and Wages	50000010163000	2,387.58	Exclude from account noted, included in account 920
Salaries and Wages	50000010182300	(1,081.00)	Exclude from account noted, included in account 920
Salaries and Wages	50000010184000	8,497.50	Exclude from account noted, included in account 920
Overtime	50000010184000	1,887.18	Exclude from account noted, included in account 920
Outside Svs	50030010163000	32.95	Exclude from account noted, included in account 920
Outside Svs	50030010182300	88,873.97	Exclude from account noted, included in account 920
Outside Svs	50030010184000	629.00	Exclude from account noted, included in account 920
Equip & Machin Rents	50050010163000	12,038.96	Exclude from account noted, included in account 920
Fleet-Repair/Main	50122010184000	82.50	Exclude from account noted, included in account 920
Other Operating Exp	50500010107000	5,264.43	Exclude from account noted, included in account 920
Other Operating Exp	50500010163000	4,383.17	Exclude from account noted, included in account 920
Other Operating Exp	50500010182300	2,380.00	Exclude from account noted, included in account 920
Other Operating Exp	50500010184000	(43,574.10)	Exclude from account noted, included in account 920
Elec Pur Power Misc	52001010131000	0.83	Exclude from account noted, included in account 920
BS Lbr Offset	70200010107000	962.31	Exclude from account noted, included in account 920
BS Lbr Offset	70200010142000	(13,353.12)	Exclude from account noted, included in account 920
BS Lbr Offset	70200010184000	(33,506.88)	Exclude from account noted, included in account 920
BS Other Offset	70204010184000	36,899.19	Exclude from account noted, included in account 920
BS Ops OH Benefit	70211010184000	(20,928.41)	Exclude from account noted, included in account 920
BS OH Payroll Tax	70211210184000	(3,149.64)	Exclude from account noted, included in account 920
BS OH Pension/OPEB	70211310184000	(3,220.01)	Exclude from account noted, included in account 920
BS OH Prop Ins	70211410184000	(1,812.72)	Exclude from account noted, included in account 920
BS Ops Vac Allocatin	70211610184000	(4,915.45)	Exclude from account noted, included in account 920
Lbr Alloc	80000010163000	35,666.14	Exclude from account noted, included in account 920
Lbr Alloc	80000010184000	62,982.99	Exclude from account noted, included in account 920
OH Benefits	80111010184000	21,005.17	Exclude from account noted, included in account 920
OH Payroll Tax	80111210184000	6,896.56	Exclude from account noted, included in account 920
OH Pension/OPEB	80111310184000	7,050.63	Exclude from account noted, included in account 920
OH Prop Ins	80111410184000	3,969.19	Exclude from account noted, included in account 920
OH Vacation	80111610184000	10,763.03	Exclude from account noted, included in account 920
OH Inj&Damage	80111810184000	6,148.21	Exclude from account noted, included in account 920
OH Bonus	80111910184000	7,028.62	Exclude from account noted, included in account 920
OH IT Costs	80114110184000	10,719.03	Exclude from account noted, included in account 920
OH Rent	80114210184000	924.44	Exclude from account noted, included in account 920
OH A&G N-Labr	80117010184000	15,267.82	Exclude from account noted, included in account 920
WBS ST Lbr-Intrc	85400010142000	29,179.04	Exclude from account noted, included in account 920
WBS ST Lbr-Intrc	85400010184000	(32.80)	Exclude from account noted, included in account 920
WBS ST Other-Intrc	85404010184000	(6.83)	Exclude from account noted, included in account 920
WBS ST OH Ben-Intrc	85411010184000	(25.29)	Exclude from account noted, included in account 920
WBS ST OH PrlTx-intr	85411210184000	(3.08)	Exclude from account noted, included in account 920
WBS ST OH Pn/OPEB-in	85411310184000	(3.15)	Exclude from account noted, included in account 920
WBS ST OH PrIn-Intrc	85411410184000	(1.77)	Exclude from account noted, included in account 920
		258,778.99	

The $26,484.13 variance between the FERC Form 1 account 921, Office Supplies and Expenses, and the SAP account 921 related general ledger accounts, as above, was noted to be accounts and/or entries that were in the FERC Form 1 in the income statement, but in the actual SAP in balance sheet accounts. Specifically:

Comp Exp-Repair	50211010921000	14,040.00	107, Construction Work in Progress
OH A&G N-Labr	80117010921000	218.89	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	99.20	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	169.42	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	2,576.06	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	33.27	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	148.82	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	392.85	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	2,996.17	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	42.36	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	263.84	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	92.29	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	710.01	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	570.27	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	2,805.73	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	92.83	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	19.67	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	156.90	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	103.62	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	831.18	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	15.73	242, Miscellaneous Current and Accrued Liabilities
OH A&G N-Labr	80117010921000	105.02	242, Miscellaneous Current and Accrued Liabilities
		26,484.13	

The $498,951.66 variance between the FERC Form 1 account 922, Administrative Expenses Transferred-Credit, and the SAP 922 related accounts was noted by Liberty to be:

Cost Alloc to Cap	50510010922000	$	(316,613.20)	reflected within account 182.3
Cost Alloc to Cap	50510010922000	$	(182,338.46)	reflected within account 182.3
		$	(498,951.66)	

Several entries, summing to the $5,337.34 variance between the FERC Form 1 and the SAP account 924, Property Insurance, were excluded from that account on the FERC Form 1 and included in the balance sheet account 242, Miscellaneous Current and Accrued Liabilities.

OH Prop Ins	80111410924000	93.88	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	42.55	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	72.66	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	1,104.88	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	14.27	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	63.83	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	168.49	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	1,285.07	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	18.17	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	113.17	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	39.58	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	304.53	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	244.59	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	1,203.39	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	39.81	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	8.44	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	67.30	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	44.44	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	356.50	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	6.75	Excluded from 924-Added into 242
OH Prop Ins	80111410924000	45.04	Excluded from 924-Added into 242
		5,337.34	

The $8,263.31 variance between the FERC Form 1 account 925, Injuries and Damages, and the SAP 925 related account total was noted by Liberty to be the following entries that posted to 925, but should have posted to account 242, Miscellaneous Current and Accrued Liabilities. The FERC Form 1 reflects what the year-end balances notedly should have been, not what the SAP reflected:

OH Inj&Damage	80111810925000	145.36	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	65.87	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	112.50	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	1,710.59	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	22.09	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	98.82	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	260.86	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	1,989.55	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	28.14	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	175.21	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	61.27	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	471.47	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	378.68	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	1,863.09	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	61.64	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	13.06	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	104.18	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	68.81	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	551.93	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	10.45	Excluded from 925-Added into 242
OH Inj&Damage	80111810925000	69.74	Excluded from 925-Added into 242
		8,263.31	

The $23,176.55 variance between the FERC Form 1 and SAP account 926, Employee Pensions and Benefits expense account was identified by the Company to be the result of several transactions that were mis-mapped to account 926 in SAP, and should have been included in account 242, Miscellaneous Current and Accrued Liabilities. The FERC Form 1, as above, was a reflection of what the ending balances notably should have been, not what the general ledger actually showed.

OH Benefits	80111010926000	305.24	Excluded from 926-Added into 242
OH Benefits	80111010926000	138.33	Excluded from 926-Added into 242
OH Benefits	80111010926000	236.25	Excluded from 926-Added into 242
OH Benefits	80111010926000	3,592.34	Excluded from 926-Added into 242
OH Benefits	80111010926000	46.39	Excluded from 926-Added into 242
OH Benefits	80111010926000	207.52	Excluded from 926-Added into 242
OH Benefits	80111010926000	547.84	Excluded from 926-Added into 242
OH Benefits	80111010926000	4,178.21	Excluded from 926-Added into 242
OH Benefits	80111010926000	59.08	Excluded from 926-Added into 242
OH Benefits	80111010926000	367.93	Excluded from 926-Added into 242
OH Benefits	80111010926000	128.69	Excluded from 926-Added into 242
OH Benefits	80111010926000	990.12	Excluded from 926-Added into 242
OH Benefits	80111010926000	795.25	Excluded from 926-Added into 242
OH Benefits	80111010926000	3,912.64	Excluded from 926-Added into 242
OH Benefits	80111010926000	129.45	Excluded from 926-Added into 242
OH Benefits	80111010926000	27.43	Excluded from 926-Added into 242
OH Benefits	80111010926000	218.79	Excluded from 926-Added into 242
OH Benefits	80111010926000	144.50	Excluded from 926-Added into 242
OH Benefits	80111010926000	1,159.09	Excluded from 926-Added into 242
OH Benefits	80111010926000	21.95	Excluded from 926-Added into 242
OH Benefits	80111010926000	146.46	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	102.43	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	46.42	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	79.28	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	1,205.43	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	15.57	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	69.63	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	183.84	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	1,402.01	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	19.82	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	123.46	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	43.19	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	332.24	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	266.85	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	1,312.91	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	43.44	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	9.20	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	73.41	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	48.48	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	388.94	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	7.36	Excluded from 926-Added into 242
OH Pension/OPEB	80111310926000	49.14	Excluded from 926-Added into 242
		23,176.55	

Recommendation

Liberty should have ensured that the actual financial records within the new SAP system were accurate, prior to filing the current rate case.

All transactional or system mapping adjustments should have been addressed. Because of the quantity of noted adjustments, and the time required to identify variances among the FERC Form 1 accounts, Audit is unable to determine if the reported adjustments are accurate nor if they represent all of the adjustments that should have been done.

Company Comment

Liberty Granite State ("Liberty") appreciates Audit Staff's review and efforts during its audit, specifically, recognizing that additional efforts by Audit Staff were required to translate how accounts and transactions previously reflected in our legacy system now appear in SAP. As a result of this transition, additional audit explanations were necessary that required additional time and attention from Audit Staff. We also appreciate that we need to take the lead on providing those "translations" and making the transition to the new accounting system as seamless as possible for Audit Staff and other parties in this proceeding.

That said, the Company does not agree with Audit Staff's conclusion that the Company failed to ensure that its actual financial records within the new SAP system were accurate prior to filing the pending rate case. The financial records are accurate. There are simply some differences in the way that costs are recorded in one system or the other. These differences are known and allow for "mapping" of data from the new system to the protocols required for financial reports, such as the FERC Form 1. It is also important to note that the Company's 2022 financial statements were audited by the Company's independent auditors, Ernst & Young ("EY") and a copy of EY's audit opinion was previously filed as part of the Company's standard filing requirements, Puc 1604.01(a)(13)… In its audit opinion, EY concluded that:

> …[the] financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022, and the results of its operations and its cash flows for the year then ended in accordance with generally accepted accounting principles.

In addition, the Company had EY review the Company's FERC Form 1, and EY similarly determined the FERC Form 1 to be accurate…Liberty has also provided information to Audit Staff to substantiate all adjustments.

Also, please note that, subsequent to the parent company closing the books for 2022 year-end, Liberty identified "Unadjusted Differences" of approximately $848k that were discussed with EY and management. Liberty has correctly reflected those amounts in the revenue requirement, as described in responses to DOE 10-21 and DOE 11-14. "Unadjusted Differences" are not unusual in any reporting year and will occur from time to time, regardless of a change in accounting systems. With the Unadjusted Differences reflected in the revenue requirement, the FERC Form

1 maps directly to the data recorded in Liberty's financial system. The Company has provided a trial balance to Staff that provides the direct mapping to the FERC Form 1.

Audit Comment

Audit understands the efforts put forth by the Company to deal with a system conversion, the compilation of two full rate filings (Granite State and EnergyNorth), and the completion of the FERC Form 1.

Audit is also aware of, and had read, the E&Y financial reports. Language included in the Company Response is language typically found in the disclosure of any financial review conducted by external auditors. Those disclosures also include the fact that the information in the report is based on Management's representation.

Audit also understands that the E&Y audit was conducted in conjunction with the APUC corporate "natural" account as the primary focus. While the audit did not result in any material misstatements, the external auditors did not appear to appreciate the importance of the verification and validation of the reported figures within the FERC Form 1 to the SAP year-end balances.

Liberty also informed Audit that "*The Company, along with our external auditors, determined to not reflect these adjustments in the FERC Form 1 to align with previously presented financial information in the APUC Form 10-K Annual Report and Granite State Electric standalone financial statements. The adjustments were correctly reflected in the Revenue Requirement…capitalized amount was not recorded for GAAP purposes to align with the Parent Company (APUC) Form 10-K filing and not have differences between those GAAP filings.*"

The Company must ensure that the financial accounts of Granite State Electric truly support the accounts as reflected in the FERC Form 1. Mapping issues, or translations of portions of accounts are not consistent with the FERC USoA.

Audit Issue #2
Accumulated Depreciation and Cost of Removal

Background

Audit compared the year-end SAP balances to the FERC Form 1 and to the Company's Revenue Requirement schedules.

Issue

The filing schedule RR-4 indicates the Accumulated Depreciation balance is $123,210,870. This is a $120,158 difference compared to the 2022 FERC Form 1. The variance is comprised of a ($1,412.71) balance in account 15520010108000 Accumulated Depreciation-FC-Leg, and $121,570.85 balance in the RWIP account 15550010108100.

Accumulated Depreciation and Amortization

		SAP and FERC Form 1	**RR-4, Line 2**	**CPR**
15030010108000	Accrued Cost of Removal	$ (8,010,584)	$ (8,010,584)	
15501010108000	Acc Dep-Plant in Service	$ (102,547,907)	$ (102,547,907)	
15520010108000	Acc Dep-FC-Legacy	$ (1,413)		
15551010108000	RWIP Reclass	$ -	$ -	
15501010108000	Acc Dep-Plant in Service	$ (188,068)	$ (188,068)	
15550010108100	RWIP	$ 121,571		
26150010108110	Long term Cost of removal	$ (258,610)	$ (258,610)	
15501010111000	Accumulated Dep-Plant in Service	$ (12,205,701)	$ (12,205,701)	
	FERC Form 1	**$ (123,090,712)**	**$ (123,210,870)**	**$ (123,180,534)**
	variance to SAP and FERC Form 1		$ (120,158)	$ (89,822)

Neither account highlighted in yellow is included in the filing. The Company provided the following explanation: "*$121,571 in RWIP is Removal Work in Progress and therefore would not be included in the revenue requirement. The $1,413 in Legacy Costs represent two salvage cash payments. These amounts should have been included in the revenue requirement. They were inadvertently excluded because they were posted directly to the legacy account and therefore never settled properly through a WBS# in SAP to depreciation reports. The Company will consider this, along with any other changes identified during the discovery process, in its next update of the revenue requirement in this proceeding.*"

The 2022 CPR records indicate the test year Cost of Removal charges are ($1,472,496) while the FERC Form 1 page 219 indicates ($1,563,731). This is a $91,235 difference.

Recommendation

Audit agrees that the Retirement Work in Progress account should not be part of the filing, because CWIP is also not included. However, Audit does recommend that the filing schedule RR-4 be updated with the $(1,413), as the Company noted.

The Cost of Removal and CPR records should agree. The Company should perform any necessary adjusting journal entries and adjust any filing schedules to reflect the adjustment.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding and will perform the necessary adjusting journal entries.

Audit Comment

Audit concurs, and requests that copies of any adjusting journal entries be provided to Audit within 30 days of this Final report.

Audit Issue #3
Repeat Issue
Capitalizing Fleet/Equipment Depreciation

Background

The Company has been capitalizing fleet/equipment depreciation since 2018 when they adopted FASB ASC 360. In the Audit Report, Audit Issue #3 of the DE 19-064 audit work, it was noted that the capitalization is the monthly depreciation expense of grouped asset 8830-3920, multiplied by the quarterly fleet depreciation rate capitalized to CWIP jobs through inclusion in the BRD calculation.

Issue

The Company capitalizes a portion of depreciation on vehicles in account #392 and equipment in account #396 to FERC account 107 CWIP. The calculated depreciation is posted to regulatory accounts 55056010403000 Capitalized Equipment and 55057010403000 Capitalized Fleet. A journal entry is then done each month to move a percentage of this depreciation to the 107 CWIP account where these amounts are allocated across capital projects. For 2022:

55056010403000 Capitalized Depreciation- Equipment	($52,491)
55057010403000 Capitalized Depreciation-Fleet	$79,367
Net Capitalized Depreciation	$26,876

In response to this issue in the prior rate case audit, Liberty noted:

"*The capitalization of depreciation on construction vehicles to account 107 balance is appropriate under the guidance set forth by US GAAP* [Financial Accounting Standards Board FASB] *standard ASC 360. The entry to capture the capitalization of vehicle depreciation used in construction activities is a debit to CWIP, account 107 and a credit to depreciation expense account 403. Thus, the depreciation expense is not overstated and the Accumulated Depreciation is not understated.*"

Recommendation

As noted in the prior report, Audit recommends that the Company comply with the FERC Uniform System of Accounts, make any adjustments to filing schedules removing the capitalized equipment/fleet charges from the filing.

The Company must also adjust the Plant in Service balances which have been impacted by the capitalization of fleet depreciation, for all years 2018 through current.

Company Response

As to the adjustment to Plant in Service balances for 2018 through current, Liberty disagrees with Audit's finding as the Company has followed the guidance set forth by US GAAP standard FASB ASC 360 since 2018. As such, no adjustments to the Plant in Service balances are required.

As to the adjustment to the Rate Years, Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit is unclear regarding the disagreement for plant balances impacted since 2018, but the Company's agreement to adjust plant in service for the test year only, and in the filing only.

Audit restates that for all years from 2018 through current, the Company should not capitalize fleet depreciation.

Audit conferred with a representative from the FERC Enforcement division, who supported the Audit staff's interpretation of "depreciation" that can be included in Construction Work in Progress, and agreed that fleet depreciation generally does not conform with the FERC Uniform System of Accounts. That representative noted that regulated utilities must conform to FERC over GAAP and ASC 360 in this instance.

Audit also understands that this issue should be resolved within the context of this rate case, and defers to the Regulatory division of the Department of Energy and the Company to ensure a clear and concise resolution of this ongoing issue.

Audit Issue #4
Repeat Issue
EAP Upgrades CIAC

Background

The Company did software upgrades that were recovered through the System Benefits Charge.

Issue

On June 1, 2023 the DE 21-133 Energy Assistance Program Final Audit Report was issued. A repeat Audit Issue #1 identified $140,000 in EAP costs the Company was authorized to recover on June 1, 2021 per Order 26,485 through the EAP/SBC funding mechanism. The Order included:

- *"Liberty originally requested recovery of $195,666 in the joint petition"*
- *"Liberty acknowledged during the March 4, 2020, hearing that, upon further refinement, its actual costs were approximately $160,000"*
- *"At the hearing, Liberty requested approval for recovery in the amount of $140,000, consistent with the Settlement Agreement, stating that it would request recovery of the remaining costs (approximately $20,000) in a pending rate case"*
- *"In the Settlement Agreement…. they agreed that Liberty had prudently incurred costs of $140,000 to implement the changes required by Order No. 26,132. The Settlement Agreement contained a table showing that an invoice had been incorrectly charged to Liberty's project, so that the correct total was $160,753 rather than $195,666. It also noted that Liberty agreed to seek recovery of $140,000 from EAP funds in this docket and to request the remaining* ***$20,753*** *in a pending rate case"*

The June 2023 Audit Report further indicates that Liberty, in their updated March 15, 2023 EAP reconciliation filing, recovered the $140,000 costs associated with the required EAP technical system upgrades.

Since the $140,000 EAP billing system upgrade costs were recovered through SBC funds the Company should include the plant additions to rate base without at least entering the reimbursement costs as a Contribution in Aide of Construction (CIAC).

Recommendation

The Company should remove $140,000 EAP billing upgrade plant additions from the filing schedule, general ledger, and continuing property records, or provide evidence that the offset to CIAC has been booked and the filing updated to reflect that entry.

In response to the Audit Issue #6 in the DE 19-064 audit report issued in January 2020, in which $168,498.10 had been booked to plant in service, the Company noted:

"*The Company agrees that due to the difference in timing between the incurrence of costs in 2018 and the receipt of reimbursement funding from the SBC (expected during 2020) the costs should be removed from the rate case filing. As the funds received from the SBC will be treated as CIAC and offset the cost of the upgrade, if the reimbursement was received in the same year the costs were incurred there would be no impact on plant in service. However, as the rate case* *has a test year that ended December 31, 2018, the costs should be removed to avoid setting rates that include the system upgrade costs.*"

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

While Audit concurs with the Company adjusting the filing, the Company is requested to provide the adjusting journal entries and/or removal from the continuing property records.

Audit Issue #5
Project Addition Backup

Background

Audit reviewed twelve 2019-2022 project plant additions that included the budgeted vs. actuals amounts, charge detail, project cost of removal, Project Retirement entries, Business Cases, Project Capital Expenditure Forms, Change Order, and Closeout support.

Issue

Budget vs. Actual

The Company, when asked to provide reasons for projects budgeted vs. actual amount variances, indicated to Audit to review the specific business cases/project closeout details. On all the projects reviewed, the Business Cases/Project Closeouts did not give a specific reason other than in some instances projects were reallocated to other ones to meet budget priorities during the year. The Project Closeout Reports also contained many large variances when compared to what was actually spent.

Bids

The Company, on a few projects, indicated projects were done internally and that is why they were not put out to bid. The Company did not provide the bid details for the 8830-2083 Ten Year Inventory Improvement other than indicating they found a contractor that met their needs. Based on a review of a few projects the cost detail is solely for contractors so that means the project was not done internally and the Company should have gone out to a competitive bid if one was not done. This affects the following projects:

Should have been bid competitively:
Project 8830-1956 Install 13L2-9L3 Feeder Tie
Project 8830-2025 IT Systems and Equipment Blanket

Cost of Removal and Retirements

The Company for several projects did not specify a reason for why any cost of removal (COR) or retirement entries were not done. The Company did specify install only projects do not have any cost of removal entries. The Company did acknowledge that they were presently behind on retirement entries because of the recent conversion to SAP/PowerPlan in October 2022 and will need to get caught up.

No COR entries Completed
Project 8830-2127 IT Systems Allocations-Corporate
Project 8830-2241 Feeder Getaway Cable
No Retirement Entries Completed
Project 8830-1954 Mt. Support Lebanon 16L2-L5 Feeder
Project 8830-1956 Install 13L2-9L3 Feeder Tie
Project 8830-2025 IT Systems and Allocations
Project 8830-2127 IT Systems Allocations-Corporate
Project 8830-2139 URD Cable Replacement
Project 8830-2119 Transformer Upgrade
Project 8830-2241 Feeder Getaway Cable
Project 8830-2210 Distributed Street Light Replacement

Missing Documentation

The Company was missing specific documentation for Business Cases, Project Capital Expenditures Form, and Project Closeouts. The following projects were missing key documentation.

Project	Document
8830-1956	Project Capital Expenditure Form
8830-2127	Project Capital Expenditure Form
8830-2083	Project Closeout Form

Unitized Amount Varies from Project Closeout Report

Several projects' actual unitized plant in service amount is different than what was indicated on the signed project closeout forms.

Project	Project Closeout	Actual Plant in Service	Difference
8830-1956	$227,672	$246,037	$18,365
8830-2024	$82,118	$257,404	$175,286
8830-2013	$136,432	$185,925	$49,493
8830-2139	$36,295	$235,107	$198,812
8830-2119	$33,293	$38,828	$5,535
8830-2241	$122,213	$119,779	($2,234)
8830-2210	$81,617	$133,309	$51,695

Materials and Supplies Journal Entries not Supported with Inventory Ticket or Detail

The materials support provided by the Company did not contain any invoices or historical inventory tickets details, rather, solely a journal entry of the transaction amount and quantity.

2019

Project	Description
8830-1932	Lebanon High Voltage
8830-1954	Install Mt. Summit Feeder Cable
8830-1956	Install 13L2 Feeder Cable

2021

Project	Description
8830-2119	NN Transformer Upg.

2020

Project	Description
8830-2024	LED Streetlight Replacement

2022

Project	Description
8830-2241	Feeder Replacement
8830-2210	Streetlight Repl.

AFUDC Embedded File

The Company indicated the AFUDC backup was in an embedded file but there were no embedded files other than the GL transaction Audit sampled. This affects the following projects.

2019

Project	Description
8830-1954	Install Mt. Summit Feeder Cable
8830-1956	Install 13L2 Feeder Cable

2020

Project	Description
8830-2024	LED Streetlights

Overhead Embedded File and Percentages Exceeding 30%

The Company indicated they provided the Overhead calculations/backup for the plant additions review in an embedded file that was not attached to the provided file. A number of projects have an overhead rate exceeding 30% that seems rather elevated for the amount of the project. The following projects had an overhead rate that exceeded 30%.

Year	Project	Description	Overhead %
2019	8830-1962	Lebanon Low Area Voltage	51.78%
2019	8830-1954	Install Feeder Tie Lebanon	47.58
2020	8830-2024	Install LED Streetlights	45.23
2020	8830-2025	IT Systems and Equipment Blanket	105.14%
2020	8830-2013	Distribution Asset Replacement	48.42%
2021	8830-2139	URD Cable Replacement	54.04%
2021	8830-2119	Transformer Upgrades	58.06%
2022	8830-2210	Install LED Streetlights	39.44%

Recommendation

The Company should make any adjustments to the filing schedules, to the correct actual plant in service balances for projects based on the explanations for variances.

The Company should review project budgeted vs actual costs and document why there are variances.

Going forward the Company should book retirements/Cost of Removal in a more timely manner.

The Company should focus more on following the LU Capital Expenditure Policy having specific project documentation such as Business Cases, Capital Expenditure Forms, and Project Closeouts. The Company should pay better attention to project bids as the Company indicated two projects were done internally when they were not.

The Company should have provided actual materials inventory invoices or tickets rather than solely journal entries, so a detailed review of materials used could have been accomplished by Audit.

The Company should have provided the complete AFUDC documentation, as the file provided did not contain an embedded file other than the sample entry Audit chose for the addition review.

The Company should have provided the complete Overhead backup, as the file provided did not contain an embedded file other than the sample Audit chose for the addition review. The overhead rates on several of the projects reviewed exceeded 30% and the Company should look for ways to lower this percentage.

As noted by the Company in response to Audit Issue #2 in the DE 19-064 audit report dated 1/16/2020:

"*In addition to improvements bulleted above (monthly budget meetings, increased level of review, designated resources and improved processes around recording and tracking accruals), the Company has also implemented a dedicated operations finance resource to oversee financial planning and reporting aspects of the Operations and Engineering groups. Additionally, the Company is in the final planning stages for tracking and allocating burdens and overheads in a manner that will allow project managers to better forecast and manage the financial budget of capital projects.*

As previously mentioned in this and prior rate cases, the management of capital projects often involves changes in scope and shifts in focus of projects to be completed in order to conduct reliable, safe and efficient operation of the business. With a newly dedicated resource supporting the operations and engineering groups, the company will be more focused on developing and implementing improvements to the process around capital spending."

Company Response

Please see below for the Company's response to the Audit recommendations. Please note that the responses are in order of appearance as presented in the recommendation.

Budget vs. Actual

Since actual costs were used to calculate the plant in service balances, no adjustments to the Company's filing schedules to correct actual plant in service balances are needed.

Bids

The Company agrees, and notes that the Company reviews budgeted vs actual costs and documents variances through Liberty's change order process as documented in the LU Capital Expenditure Policy.

Cost of Removal and Retirements

The Company agrees. Liberty is working towards a more timely recognition of actual and retirement reporting.

Missing Documentation

The Company follows the LU Capital Expenditure Policy. However, the Company acknowledges that two projects were incorrectly identified as being completed internally and upon further review were determined to have been completed by a third party.

Unitized Amount Varies from Project Closeout Report

Projects typically have late charges for adjustments after the required close document 90 days from completion. These charges can cause a difference between the close-out and the unitized in-service cost. A few selected projects are also blanket projects, for example, 8830-2013 asset replacement, that opened and closed every year.

Materials and Supplies Journal Entries not Supported with Inventory Ticket or Detail

The Company provided Audit with the best information available for a detailed review to be accomplished. The Company disagrees that the only information it provided was journal entries, as the Company also provided inventory transaction details in the subledger associated with the transaction requested. The information provided indicated the job name and number for each project that materials were charged to as well as the quantity and the cost at the time of issue from stock. Additionally, the information provided included a description of the material that was used for those particular jobs. Lastly, the information provided included the cost of each item as it left the warehouse. Materials are issued to jobs on an average cost method, so the price of materials potentially moves as material is received. The Company can provide information on its purchase price, but it will not likely match due to the recalculation of the unit costs at the time of receipt.

AFUDC Embedded File

The Company would like to clarify that what was provided in the Company's prior response to Audit's question were not sample entries, they were actual entries documenting how AFUDC was calculated.

Overhead Embedded File and Percentages Exceeding 30%

The overhead rate is a function of overhead costs that include administrative and general operating costs necessary to maintain daily operations and administer the business.

Audit Comment

Audit appreciates the specific response by the Company.

- Audit understands the Company booked the appropriate actual project costs to plant in service, so the Company feels no adjustments to the filing schedule are necessary. Audit reminds the Company that project documentation such as project closeouts should include a detailed analysis of why projects over budget or under budget compared to the actual costs. Going forward, the Company should pay closer attention to why some projects are over or under budget this will help to better manage Company resources more efficiently.

- Audit appreciates that the Company acknowledged two projects should have been put out to bid and the Company is trying to follow the internal LU Capital Policy.

- The Company should continue to address the cost of removal and retirement entries to ensure Plant is not overstated.

- Adherence to the LU Capital policy so project documentation for Business Cases, Change Order, Authorizations, and Project Closeouts are completed and accurate should be more closely monitored.

- Audit appreciates the response by the Company that there were late charges 90 days after the project close documentation that explain the difference between the unitized to plant in service figure compared to the project closeout. Going forward the Company should complete Project Closeout Reports that more accurately reflect the actual project costs that were unitized to plant in service.

- Audit appreciates the clarification regarding materials. The Company did provide materials backup that was identical to the GL entry detail that included the cost and the specific items used. Audit appreciates the Company clarifying the average cost method with regard to historical plant record transactions that the figures would be different as they leave the warehouse based on how the allocations are done.

- Audit appreciates the response by the Company regarding the AFUDC entries. Audit was able to review the actual GL entry but going forward the Company should provide the contractual details for the borrowed amount and debt portion. Audit appreciates the response with regards to overhead but reiterates the Company going forward should keep the overhead charges to the minimum costs needed to complete projects.

Audit Issue #6
Cost of Removal Booked Incorrectly

Background

Audit reviewed cost of removal generally and in the context of the specific plant additions tested as part of this audit.

Audit Issue

FERC requires that Cost of Removal entries be debited to Accumulated Depreciation. Audit noted charges to accounts 1084 and 242 throughout the testing of specific plant addition projects:

2019: Project 8830-1962
Solely 8830-2-0000-20-2124-2420 Accrued COR $19,278 entries done January 2019.

2020: Project 8830-2024
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $17,978 entries November and December 2020 were correctly posted.
8830-2-0000-20-2124-2420 Accrued COR $51,907 entries are July-December 2020

2020: Project 8830-2025
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $7,724 entries November and December 2020 were correctly posted.
8830-2-0000-20-2124-2420 Accrued COR $33,809 entries are June 2020 to August 2022.

2021: Project 8830-2139
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $5,350 correctly posted.
8830-2-0000-20-2124-2420 Accrued Cost of Removal $1,467

2022: Project 8830-2210
8830-2-0000-10-1655-1084 Accumulated Depreciation COR $13,874 entries February and March 2021 were correctly posted.
8830-2-0000-20-2124-2420 Accrued COR $242 entries are November-December 2019

The Company should not be debiting the 242 Accrued Cost of Removal account.

As noted in the DE 19-064 Audit Issue #7:

> *FERC account #***108 st***ates "at the time of retirement of depreciable electric utility plant, this account* ***shall be charged*** [debited] ***with the book cost of the property retired and the cost of removal*** *and shall be credited with the salvage value and any other amounts recovered, such as insurance. When retirement, cost of removal and salvage are entered originally in retirement work orders, the net total of such work orders may be included in a separate subaccount hereunder…"*
>
> *FERC account #242 states "This account shall include the amount of all other current and accrued liabilities not provided for elsewhere appropriately designated and supported so as to show the nature of each liability. Items (nonmajor only) 1. Dividends declared but not*

paid 2. Matured long-term debt 3. Matured interest 4. Taxes collected through payroll deductions or otherwise pending transmittal to the proper taxing authority."

The Company Response to the DE 19-064 Audit Issue #7 included:

"***While the Company will follow the FERC Uniform System of Accounts by recording its cost of removal in Account 108 Accumulated Depreciation for regulatory purposes****, the Company will continue to utilize Account 242 Miscellaneous Current and Accrued Liabilities for GAAP financial statement reporting purposes. Account 108 will be utilized for day to day entries.* ***A journal entry for the cost of removal (reclassify Account 108 to Account 242) will be made on the consolidating company level to conform to GAAP reporting requirements***." Emphasis added.

Audit Recommendation

Audit reminds the Company of its commitment to record cost of removal entries in compliance with the FERC Uniform System of Accounts, and appreciates that it appears they are trying to comply.

The reader is reminded of the Company response to the variance noted in **Audit Issue #2** of this report.

Company Response

On the regulatory ledger, the Company follows the FERC Uniform System of Accounts by recording its cost of removal in Account 108 Accumulated Depreciation for regulatory purposes.

On the GAAP ledger, for GAAP financial statement reporting purposes, the Company utilizes Account 242 Miscellaneous Current and Accrued Liabilities. Account 108 is utilized for day-to-day entries. A journal entry for the cost of removal (reclassify Account 108 to Account 242) is made on the consolidating company level to conform to GAAP reporting requirements.

The regulatory ledger was provided to Audit for review. The Company records cost of removal in the proper account and therefore the Company does not view this as an audit issue that impacts this rate case.

Audit Comment

Audit reviewed the complete activity of the Accumulated Depreciation Cost of Removal account 108, and noted its accurate use beginning in 2020. During 2019 and prior, the 242 account had been debited rather than the 108 account. However, within the samples tested, use of the 242 account was noted.

Audit Issue #7
Materials Expense

Background

The Company inventory reports, and GL figures are different from one another.

Issue

The Company, in the response to DOE Staff Data Request 4-8, provided 2020-2022 Historical Stock Status Detailed Inventory Reports. The Excel attachment DOE 4-8-1 and DOE 4-8-2 indicate the December 2022 Historical Stock balance per the report is $4,259,944 while the GL accounts summed to $3,759,408. This is a ($500,536) difference.

Account #	Amount	DOE 4-8-1 and 4-8-2	Variance
12100010154000	$4,259,944		
12100510154000	($501,827)		
12101510154000	$1,291		
Total	$3,759,408	$4,259,944	$(500,536)

Recommendation

The Company should make any adjustments to the filing schedule as the inventory reports and GL figures should reflect the same figure.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company response.

Audit Issue #8
Timing of Recording Transactions

Background

Account 131 (Cash): Per the FERC Form 1 and the General ledger the account balance the Company reported was $43,238,110.63 as of 12/31/2022.

Issue

Account 131 (Cash): The Company provided a cash reconciliation showing a ($210,283,306.62) difference between the SAP GL and the reconciliation that detailed reported GL balances. The Company advised that an entry posted after the reconciliation was completed.

Recommendation

The Company should ensure timely recording of entries to avoid large discrepancies between the reconciliation and the general ledger, and should have ensured that all roll-forward balances were properly recorded from Great Plains to SAP in a more timely manner.

Company Response

Account 131 (Cash)

Based on the above description of the issue, Liberty disagrees with the conclusion that a non-timely recording affected the Audit's review. As noted above, the Company identified a discrepancy and made an adjusting entry prior to filing its rate case. That adjustment was also made prior to EY's audit of the Company's financials and FERC Form 1.

Audit Comment

Audit understands that the filing reflected the adjustment. Audit reviews the financial statements, and internal controls such as reconciliations, to ensure that the general ledger itself is appropriate.

Audit Issue #9
Accounts Receivable Aging

Background

Audit requested and was provided with the customer level aged accounts receivable listing as of December 31, 2022.

Audit Issue

The aged accounts receivable listing is the total of 44,826 specific customers, the total of which reflected $21,567,622.35. Audit was unable to verify the total per the aged receivable to any combination of the nine SAP year-end balances, which in full, sum to $29,736,311.52.

A reconciliation was provided demonstrating:

Accounts Receivable debit balances	$19,814,926.03
Accounts Receivable Credit balances (Unapplied Payments)	$ (609,186.12)
Net Accounts Receivable	$19,205,739.91

The Company noted that the "*aged trial balance report did not tie out exactly to the general ledger, but it was determined that the variance was immaterial*", $6,354.47, or 0.03% when $19,205,739.91 was compared to another unknown receivable figure of $19,212,094.38.

Audit Recommendation

Audit encourages the Company to ensure that "*additional reports*" developed since the year-end reconciliation "*to clarify differences (mostly due to timing), but these reports were not available in December 2022*" function in a manner that will allow a true reconciliation of the supporting aged listing to the specific general ledger account or accounts.

Company Response

In January 2023, the Company developed a report titled "Display Totals for Posting" to reconcile any timing differences between the A/R aged trial balance report and the General Ledger allowing a reconciliation of the A/R aged trial balance to the specific GL account. The report provides the detail by GL account of the items that did not post from the CIS system to the GL. The Company performs this reconciliation of the A/R aged trial balance report every month, in addition to reconciling the individual general ledger account balances monthly.

The Company has not experienced any errors with items not posting to the general ledger for Granite State since January 2023.

Audit Comment

Audit appreciates that a report has been developed, and looks forward to reviewing the implementation of its use within the next audit.

Audit Issue #10
Interest on Customer Deposits

Background

Audit reviewed activity within the Interest Accrued from Customer Deposit general ledger account, within Great Plains, and requested clarification of an entry in the amount of $259.59 that posted 9/27/2022 in 8830-2-0000-20-2116-2370.

Audit Issue

The Company noted that the figure represented interest for 241 customers' deposits. As a result of the request for clarification, the Company identified a miscoding between Granite State Electric and EnergyNorth, which was identified and corrected during the test year. Liberty also noted that they "*discovered a coding error for 57 of the 3,219 GSE accounts with security deposits, which has prevented these customers from receiving their interest. The Company will make the correction and post the missing interest to the customers' accounts. The total amount of security deposits held for these 57 accounts as of December 2022 is $10,530. The estimated deposit interest owed based on the 5.5% rate in effect for that period is $145*."

Audit Recommendation

Audit reminds the Company that it must comply with the Puc 1200 rules and ensure that all customers have the monthly interest applied.

Company Response

Liberty concurs. The underlying error has been corrected.

Audit Comment

Audit concurs with the Company response and will verify the accuracy of it as part of the next rate case audit.

Audit Issue #11
Interest Income

Background

Prior to 9/30/2022, the Interest Income had been reported on GP general ledger account 8830-2-0000-40-4420-4190. The Interest Income is currently mapped to SAP account 10419000, as of 10/1/2022.

Issue

FERC Form 1 and the filing schedule 1604.01(a)(1)(a) reflects a total for Interest Income of:

Account	Description	Balance
47030010419000	Interest Income	$ (259,745.02)
47050010419000	Rental Income	$ (22,217.35)
	Total Interest Income	$ (281,962.37)

The SAP account 10419000, Interest Income, erroneously included a total of $(22,217.35) in monthly income, from October through December, for two of the Company's tower rental agreements.

The $(22,217.35) was not included in the filing schedule RR-2.3 for income associated with rent, account 10454000

Recommendation

The Company should update the Revenue Requirement filing schedules to include the Rental Income $(22,217.35).

The Company should update the accounting to ensure that Rental Income is posted to the correct SAP account, 10454000, Elec Rev Other.

Company Response

Liberty concurs and will incorporate the recommended adjustments in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company adjusting the filing.

Audit Issue #12
Revenue

Background

Audit reviewed the filing schedules to ensure that the revenue included all accounts.

Audit Issue

Based on a review of the FERC Form 1, and the general ledger accounts that support the revenue, the revenue in the filing is understated by $(383,135). Audit noted account OCOA/400330 Electric Revenue-Other, 10407300 $(383,135) on the Depreciation and Amortization Revenue Requirement schedule RR-2.12, line 8. The Company did proform it out of the Depreciation and Amortization schedule, but did not proform it into RR-2, RR-2.2, or RR-2.3.

Audit Recommendation

Audit recommends that the Revenue schedules in the filing be updated to include the additional $(383,135).

Company Response

Liberty disagrees on the basis that an update such as the one proposed by Audit would have no effect on the rate case. Specifically, the pro forma adjustments made by the Company on RR-2.3 ensure that the test year pro forma revenue reconciles to forecasted normalized revenues.

Audit Comment

Audit disagrees. The filing begins with the actual revenues during the test year.

Audit Issue #13
Payroll General Ledger

Background

Audit reviewed the payroll registers for both weekly and bi-weekly paid employees for the final pay period of 2022.

Audit Issue

Prior to the switch from Great Plains to SAP, GSE used an Opex Capex report to reconcile the payroll to the general ledger. While on-site to review the confidential payroll registers, Audit requested the Opex Capex report for December 2022. It was noted that the Opex Capex report is no longer available since moving to SAP. It was also noted that a replacement report has not yet been established.

Audit requested the reconciliation process and the report used to reconcile the payroll to the general ledger. The response provided the process and a reconciliation of the timesheet report to the payroll register. The reconciliation process did not include reconciling the payroll registers to the general ledger

Audit Recommendation

As reconciling the general ledger is an important step in providing accurate account details, Audit recommends that GSE prioritize a replacement report to the Opex Capex report.

Company Response

The recommended report was already developed and was provided in the Company's response to DOE 4-16(c) on September 8, 2023.

Payroll is reconciled to the general ledger at each pay date.

Audit Comment

Audit reviewed the Company's response to DOE 4-16(c). The response noted to *"refer to Attachment 23-039 DOE 4-16.c for regular and overtime labor for the time periods requested broken down by capital, expense, and other".*

The attachment shows the monthly labor total broken down by Capital Labor, O&M Labor, and Other Balance Sheet (non-plant) Labor. The total for the year was noted to be $11,254,980.

The attachment does not contain any general ledger detail. Audit therefore reiterates this Audit Issue and recommendation as the Attachment 23-039 DOE 4-16.c does not contain the pertinent information needed to reconcile the payroll to the general ledger.

Audit Issue #14
Temporary Employees

Background

Audit requested a listing of temporary employment agencies used during the test year. Audit also requested the total expensed for the year and the general ledger accounts to which the expenses were booked.

Audit Issue

GSE's response noted that $456,528.50 was paid to Balance Professionals in 2022. They also noted that the expenses were booked to GL account 500300.

In SAP, account 500300 references that the expense is an outside service. In the Company's response they failed to include the regulatory account where the expenses were booked.

Audit reviewed the detailed GP and SAP GL and noted a total of $404,502 in expenses for Balance Professionals.

Audit was unable to verify the expense amount GSE noted, $456,528.50.

Audit Recommendation

The Company needs to provide the specific and complete general ledger detail supporting their referenced $456,528.50.

Company Response

The Company provided information for the general ledger detail for test year payments to Balance Professionals. The total expense amount has been revised to $210,344.08. The amount of $456,528.50 previously provided in response to an earlier question, was overstated as it reported the total amount paid to Balance Professionals, including payments for the service company (Company Code 8810 / 3070) and Energy North (Company Code 8840 / 3072).

Audit Comment

Audit reviewed the additional documentation provided for the test year payments to Balance Professionals. The information provided the Balance Professional general ledger activity for both Great Plains and SAP. The documentation showed the total paid to Balance Professionals in Great Plains was $111,032.77. Audit was able to verify that amount to the detail General Ledger Audit had previously received without exception.

The additional documentation provided also showed a total of $99,311.31 being paid to Balance Professionals in the SAP system. The GL detail provided does match the $99,311.31. total but does not include the vendor information to verify it was for Balance Professionals. However, only $30,393.17 could literally be identified a payments to Balance Professionals, through use of a previously provided general ledger which included vendor information.

Audit Issue #15
End of Year Accruals

Background

Audit requested the journal entries and supporting detail for the payroll accruals booked at the end of the year.

Audit Issue

The Company provided the journal entries for the payroll and vacation accruals for Company 3070, Liberty NH. The detail did not provide the allocation to GSE or the payroll support for the accruals.

Audit was unable to verify the year end payroll accruals to the general ledger detail for GSE.

Audit Recommendation

As the year end accruals are based on actual time worked, the supporting documentation should be readily available upon request.

Company Response

The Company provided additional supporting documentation for vacation accruals and payroll accruals, respectively.

Audit Comment

Audit reviewed the additional documentation provided in response to this issue. The additional support for the vacation accrual provided the total charged to each regulatory GL account. Audit was able to verify the amount of $50,394.94 to the detail GL, previously obtained, without exception.

The additional support provided for the payroll accruals also shows the amount accrued to each regulatory account. The December payroll accrual includes adjustments from October and November as the settlement process was initially set up incorrectly. However, these entries were verified to the detail GL without exception.

In prior rate case audits, GSE was able to provide the payroll support to verify the accrual amounts are correct. This detail that was previously provided included employees names, hours worked, pay rate, and unused vacation hours. With SAP, Accounting no longer has access to the level of payroll detail to tie the accrual amounts back to specific employees and pay amounts.

Although Audit was able to tie the additional documentation provided in response to this audit issue back to the General Leger, Audit is unable to determine if the accrual amounts are accurate due to the inability to provide supporting documentation to the amounts.

Audit Issue #16
Payroll Taxes

Background

Audit reviewed the $642,935 of payroll taxes that were included in the filing.

Audit Issue

During Audit's review of the payroll taxes, it was noted that following the conversion to SAP there were no payroll tax expenses booked to FERC account 408 for October, November or December.

The Company provided the journal entry detail booking the payroll taxes to Company 3071 from Company 3070. The journal entry showed that the payroll taxes were being booked to FERC account 920 and not 408.

Audit Recommendation

Audit recommends the Company update the filing moving the payroll taxes from FERC account 920 to 408. Going forward all payroll taxes should be booked to the appropriate 408 account.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding and make any necessary correcting entries. Going forward, the Company will book payroll taxes to the appropriate account.

Audit Comment

Audit concurs with the Company's response

Audit Issue #17
Transactions past 9/30/2022 in SAP General Ledger

Background

Transactions in the Great Plains ledger were supposed to roll forward to the SAP ledger as of 9/30/2022.

Issue

After the conversion from Great Plains to SAP, SAP Account 50500010580000 - Operation Supervision and Engineering did not show any further transactions and Audit is unsure if this is due to the mapping issue identified in this report as Audit Issue #1, or if the account truly had no further activity in it after 9/30/22.

Recommendation

The Company should review the account in question and determine if any activity after 9/30/2022 should have been posted to account 50500010580000. If mapping issues are identified, the filing schedules should be updated.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

The transactions previously charged to account 505000-10580000 for the period January through September 2022 were Fleet allocations. Fleet charges totaling $22,141 for the period October through December 2022 were reported in account 804050-10999999 which were subsequently reclassed to account 10920000. The Company will update the filing schedules to reflect the adjustment to account 10580000.

Audit Comment

Audit concurs.

Audit Issue #18
Expenses to Be Considered Non-recurring.

Background

Audit reviewed the account activity in several expense accounts, and sample tested certain expense entries.

Issue

Based on the documentation provided and the activity in the account, the following entries should be considered non-recurring:

SAP/GP Ledger	Account Number	Account Name	Amount	Description
SAP	50030010593000	Maintenance of Overhead Lines	$ 1,200.00	Storm 2113 Disallowed Costs
SAP	50030010593000	Maintenance of Overhead Lines	$ 211.98	Storm 2102 Disallowed Costs
GP	8830-2-9851-56-5210-5932	Maint of Overhead Lines - Veg Mgmt	$ 6,260.63	Disallowed Trans of Chrgs Storm 2102 to 2103
			$ 7,672.61	

Audit initially questioned several rental car expenses, and was told the costs were incurred due to the COVID-19 virus. Because the COVID-19 pandemic has subsided, Audit recommends that all of the charges below that posted to account -9302 be considered non-recurring. According to the Company some of the costs were outside of the test year, although they did not indicate specifically which ones. Overall COVID-19 expenditures were $404,409.54.

COVID Job	Total Charges	GP GL Account	Total Charges
8830-9810-COVID19	$ 3,503.66	8830-2-9810-69-5615-9302	$ 3,503.66
8830-9815-COVID19	$ 59,013.76	8830-2-9815-69-5615-9302	$ 59,013.76
8830-9825-COVID19	$ 156,245.46	8830-2-9825-69-5615-9302	$ 156,245.46
8830-9830-COVID19	$ 77.70	8830-2-9830-69-5615-9302	$ 77.70
8830-9835-COVID19	$ 2,030.75	8830-2-9835-69-5615-9302	$ 2,030.75
8830-9840-COVID19	$ 25.91	8830-2-9840-69-5615-9302	$ 25.91
8830-9853-COVID19	$ 13,225.78	8830-2-9853-69-5615-9302	$ 13,225.78
8830-9860-COVID19	$ 214.00	8830-2-9860-69-5615-9302	$ 214.00
8830-9865-COVID19	$ 13,323.06	8830-2-9865-69-5615-9302	$ 13,323.06
8830-9851-COVID19	$ 156,749.46	8830-2-9851-69-5010-9200	$ 34,201.82
		8830-2-9851-69-5615-9302	$ 17,923.18
		8830-2-9852-69-5615-9302	$ 104,624.46
Grand Total	$ 404,409.54	Grand Total	$ 404,409.54

Recommendation

Audit recommends that for the rate case consideration, the expenses above should be considered as non-recurring and removed from the filing.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding. Only $110,660.53 of the $404,409.54 was recorded during the test year (i.e., 2022).

Audit Comment

Audit concurs with the Company response.

Audit Issue #19
Expenses Outside of the Test Year

Background

FERC Account 593 (Maintenance of Overhead Lines): The Company entered into a contract with Asplundh Tree Expert, LLC for $551,986.77 in 2021. The company expensed $218,661.81 in 2021 and recorded a debit accrual entry totaling $281,017.96.

FERC Account 598 (Maintenance of Miscellaneous Distribution Plant): The Company included an accrual for $11,779.30 dated 9/15/2022 for 10 invoices from Bashlin Industries, Inc. posted to GP account 8830-2-9851-56-5210-5980.

Issue

FERC Account 593: The Company recorded a credit accrual in 2022 totaling $281,017.96 and paid $333,319.96 in expenses leaving $52,302 in 2021 expenses paid recorded in 2022. It is unclear why the Company did not record an accrual entry in 2021 for the remainder of the unpaid contract for $333,319.96.

FERC Account 598:The Company stated that all "*All inventory was received in at once on receipt RCT00062466 in GP prior to SAP cutover*" indicating all materials were received in the test year of 2022. Invoice INV 323443 totaling $465.10 was dated 3/28/2023 and had a "shipped date" of 3/28/2023 indicating items were shipped outside of the test year.

Recommendation

The Company should make any adjustments to filing schedules removing the $52,302 and the $465.10 from the filing.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs.

Audit Issue #20
Automatic Template for Calculations

Background

Audit reviewed the SAP account 912 balances that sum to the reported $(10,826.58) and requested clarification of the credit balance.

Issue

The Company identified that the upon migration from the Great Plains system to the SAP system the automatic template used to calculate capital costs had not processed correctly for October and November 2022 leading to significant reclassification entries to be made.

Account 912 Demonstrating and Selling Expenses ($10,827) is the sum of the following SAP general ledger accounts and was verified to RR-2 of the filing and FERC Form 1:

50000010912000	Salaries and Wages	$ 12,608.86
50005010912000	AllocCorp Lbr Leg	$ (4,283.25)
50010010912000	Vacation & Other TO	$ 3,369.69
50150010912000	Advertising Expenses	$ 882.12
50400010912000	AllocCorp Cap Leg	$ 318.00
50500010912000	Other Operating Exp	$(18,567.55)
50510010912000	Cost Alloc to Cap	$(22,392.47)
70200010912000	BS Lbr Offset	$ (3,222.09)
80000010912000	Lbr Alloc	$ 26,080.16
80300010912000	Assess Lbr	$(10,133.92)
80308510912000	Assess Travel	$ 230.62
85300010912000	Assess Lbr-Intrc	$ 4,560.92
85311010912000	As OH BenIntrc	$ (277.67)
		$(10,826.58)

The GP general ledger only consisted of 2 invoices from Jill M. Fitzpatrick totaling $882.12. The SAP general ledger however consisted of numerous credit entries labeled as marketing, payroll interest corrections, missed A&G assessments and true ups resulting in a large credit balance at the end of 2022. Audit questioned the Company as to the reason why there were so many entries as in previous years entries have always consisted of small vendor invoices and resulted in an overall -7318% decrease from calendar year 2021. The Company responded with the following:

The credit balance in FERC account 912 is mainly due to a correcting journal entry that was recorded in December 2022. Upon migration to SAP, the systems support team identified that the automatic template used to calculate capital costs had not processed correctly for October and November 2022, hence a reclass entry was done to correct the missed costs.

Audit is unsure if the automatic template has been corrected or if other template mitigations were processed correctly.

Recommendation

The Company should confirm that other template migrations were not affected in the GP to SAP transition and disclose if this template has been corrected for future use.

Company Response

Liberty confirms.

Audit Comment

Audit understands the Company response to be that other template migrations were not affected. It is unclear if the automatic template that resulted in this Audit Issue has been corrected.

Audit Issue #21
Expense variance

Background

The Company expensed 2 invoices from PC Connection totaling $32,374.26. The allocated portion of these invoices for GSE was $9,712.28.

Issue

The Company recorded $9,950.53 to GSE GP account 8830-2-9800-69-5130-9210 (Office Supplies & Expenses) resulting in a $238.25 overage in expenses.

Recommendation

The Company should make any adjustments to filing schedules removing the $238.25 from the filing and ensure expenses are recorded correctly.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company response.

Audit Issue #22
Charge posted to expense account rather than deferral account

Background

The Company recorded 2 invoices totaling $50,895.20 to SAP account 50254010923000. Upon submitting supporting documentation for the charges, the Company advised the following for both invoices " *Invoice was transferred to Battery Storage deferral account*".

Issue

The Company recorded 2 charges to expense account 923 when they should have been posted to a deferral account.

Recommendation

The Company should make any adjustments to the filing schedules removing the $50,895.20 from account 923 and posting them to the correct deferral account.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs.

Audit Issue #23
Regulatory Expenses vs. Political Contributions

Background

The general ledger account activity for January through September 2022 was noted in account 8830-2-9830-69-5610-9280, Regulatory Commission Expense. At conversion, the activity was rolled into SAP account 3071-50506010928000 Reg Commissions Expense.

Issue

Revenue Requirement schedule RR-2.10 and FERC Form 1 reflect a total Regulatory Commission expense of $643,455. The PUC fiscal year assessments for 2022 (July 2021 through June 2022) and 2023 (July 2022 through June 2023) summed to $651,654, $8,199 higher than the FERC Form 1 and the RR-2.10. Audit verified the difference to the net of two specific journal entries:

February 28, 2022 entry in the GP 928 activity	$ 1,800.00
December 31, 2022 reclass PUC Assess to Default Srv	$(10,000.00)

The $1,800 membership investment was part of a total Business and Industry Association membership fee of $2,400 and was incorrectly posted to the Regulatory account.

10928000 Regulatory Commission Expenses -strategic plan	$1,800	
8830-2-9868-69-7450-4264 Political Contributions	$ 600	
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$1,800
8830-2-0000-20-2810-2606 Due to Liberty Energy NH		$ 600

Recommendation

Audit recommends that the filing schedule RR-2.10 be reduced by $1,800 for account 928, and reflected within the filing schedule associated with Dues and Membership. Audit understands this has no impact on the income statement.

Company Response

The $1,800 membership dues portion was incorrectly charged to regulatory commission expenses and should have been charged to dues and membership. The Company will make this adjustment in the next update of the revenue requirement model in this proceeding.

Audit Comment

Audit concurs.

Audit Issue #24
Filing vs. Response to Staff Data Request

Background

At year-end, the SAP "Rental" expense accounts were:

3071-50130010931000 **Meals & Ent**	$132,786.40	RR-2.10
3071-50300010931000 Rental Expense	$ 71,284.90	RR-2.10, RR-3.8
3071-50304010931000 Lease Exp	$ 1,397.50	RR-2.10
3071-50500010931000 Other Operating Exp	$ -0-	
Rent Expense at year-end 12/31/2022	**$205,468.80**	

The total was verified to the FERC Form 1 and filing schedule RR-3.8

Audit Issue

In response to DOE Staff Data Request #4-48, Liberty indicated that the original filing schedule RR-3.8 did not include all of the Rental Expenses. That response showed that RR-3.8 should have reflected:

Intercompany Rental-Londonderry building annual lease	$ 59,236
Intercompany Rental-Concord Training Center annual lease	$123,893
Facility Lease E-Point for 130 Main St. Salem	$ 26,125
Facility Lease 116 N Main St. Concord	$ 854
Filing per DOE DR 4-48	**$210,108**

Audit Recommendation

It is unclear where the difference between the original filing and the updated Data Response was posted, or where within the filing it may have been originally identified.

Company Response

The Company provided additional support containing a summary of the various entries and a reconciliation to the **$213,848**.

As discussed in the Company's response to OCA 3-66, the 2022 lease expense was $213,848.30. The Company identified a correction to rental expenses included in RR-3.8 along with a small adjustment to the amount reported in DOE 4-48. The $210,108, as included in DOE 4-48, inadvertently included $4,916.50 of charges for maintenance of plant and was missing $8,657.24 relating to the Company's Salem walk-in center ($210,108 – 4,916.50 + 8,657.24 = 213,848.74).

Audit Comment

Audit reviewed the additional support, which showed:

2022	Rent Expense	SAP Reg Acct 10931000	Difference
Jan	11,764.46	11,764.46	-
Feb	17,714.62	17,714.62	-
Mar	17,714.62	17,714.62	-
Apr	17,714.62	17,714.62	-
May	17,359.79	17,359.79	-
Jun	12,423.79	12,423.79	-
Jul	22,295.79	22,295.79	-
Aug	17,359.79	17,359.79	-
Sep	17,359.79	17,359.79	-
Oct	15,142.12	10,206.12	4,936.00
Nov	24,763.51	19,922.51	4,841.00
Dec	22,235.40	23,632.90	(1,397.50)
Grand Total	213,848.30	205,468.80	8,379.50

Exclude	(1,397.50)	Legal Invoice s/b 502400-10923000
Exclude	(95.00)	Equipment Rental s/b 500500-10586000
Include	9,872.00	Londonderry lease 2 months (recorded to 503000-10921000 in error)
Revised Total	213,848.30	
OCA 3-66 Total	213,848.30	
no difference	-	

Based on the information provided, it does not appear that the income statement was impacted overall. Audit appreciates that the Company researched the inaccurate accounting and the statement that the corrections will be included in an updated filing.

Audit Issue #25
Corporate Allocations

Background

Due to the corporate structure of Liberty, monthly expense allocations are booked to the general ledger of GSE for corporate expenses.

Audit Issue

Audit requested the direct and indirect corporate billings for November 2022. The Company provided supporting documentation for eight corporate billings.

Audit reviewed the supporting documentation for the corporate billings in detail. For all eight billings, Audit was unable to verify the expense amounts to the GSE general ledger.

For the indirect billing, in which the expenses are allocate to GSE using the 4 Factor Percentage, Audit was unable to verify the correct expense amount was allocated to GSE.

Audit Recommendation

Audit recommends the Company verify the expense billing allocation amounts and the general ledger account to which the expenses are booked.

Company Response

The Company provided additional support containing the specific GL accounts where the allocated expenses are recorded on the GSE books.

Audit Comment

Audit reviewed the additional support provided in response to this audit issue and notes that a total of $628,867.06 was billed to GSE through Corporate Billings in November 2022. Of that total, only $15,818.78, or 2.5% of the total booked to GSE was verified to the detail GL.

GSE provided the regulatory GL account and offsetting account for the Direct Billing Manual LUC and Direct Billing Manual LABS journal entries. These billings only had one line of detail each. Audit verified this total of $4,785 to the SAP GL detail without exception.

The remaining six Corporate Billings reviewed had multiple lines that summed to the total charged. For these charges, GSE did not provided the regulatory account in the additional support provided. Rather, GSE provided a total per “natural” account (corporate/GAAP) for each invoice. As each natural account is associated to several regulatory accounts, Audit was only able to verify $11,033 out of $624,082 charged to GSE based on the information provided.

Audit Issue #26
Property Tax Filing Schedule RR-3.6
Adjustments to make per the June 8, 2023 PTAM Audit Report

Background

The Company reflected $4,883,044 on the filing schedule RR-3.6

Issue

On June 8, 2023 the DE 23-037 property tax PTAM Audit report was issued. The Audit report reviewed both issuances of the 2022 municipal property tax bills that summed to $4,816,970. The report identified ($28,184) in municipal property tax adjustments resulting in $4,788,786 in 2022 municipal property tax expenses. The adjustments related to the $227 Town of Charlestown for including the State Education Tax, $28,194 adjustments to the Town of Walpole related to the reported filing vs the 2022 actual amounts on the property tax bill, and a $237 allowance based on a difference between the filing and actual tax obligation due to a lower parcel assessment in Windham.

Based on a review of the RR-3.6 property tax filing schedule the Company will need to make the same ($28,184) adjustment plus an additional adjustment of ($66,074) related to Lebanon Parcels 157/1 and 157/2 that the Audit report indicates related to assets that were not placed into service and not considered used and useful. The net adjustments to the 2022 municipal installment payments are now $4,788,786 as was presented in the Audit report.

Recommendation

The Company should adjust filing schedule RR-3.6 to reflect $4,788,786 in 2022 municipal property tax expenses based on the DE 23-037 PTAM report issued on June 8, 2023.

Company Response

Liberty concurs and will incorporate the recommended adjustment in the updated version of the revenue requirement model to be filed in the proceeding.

Audit Comment

Audit concurs with the Company Response.

Audit Issue #26
Artwork

Background

Within the prior audit report, in docket DE 19-064, Audit Issue #4 identified $5,265 in artwork that was included in Plant in Service, in account #398, Miscellaneous Equipment. Audit had recommended that the amount be excluded from Plant in Service since it is not necessary for the safe and reliable provision of electrical service. The Company disagreed.

Issue

The $5,265 artwork was noted to have been part of project 8830-CNN026. In the prior report, Audit recommended that the artwork is not necessary for the provision of electrical service, and it should be expensed below the line, rather than included in account #398 and purchased with ratepayer funds.

The Company responded to the previous issue:

"*The Company disagrees with this recommendation. The artwork at issue is nothing extravagant nor excessive and consists of a number of framed prints that are on walls throughout the Londonderry facility. Without the artwork the walls would be bare except for paint. The Londonderry headquarters building is by no means opulent, and the low cost artwork provides a small measure of color to marginally enhance the workplace. The Company notes that account #398 is used for items that are not specifically provided for in other accounts, so inexpensive prints should not be considered disallowable. The Audit Staff cites to no rules or rulings in support of the recommendation. Rather, it appears this recommendation is arbitrary and, with no cited basis for the recommendation, appears solely based on the subjective opinion of an auditor. Thus, it is difficult from a Company perspective to agree to recommendations of a subjective nature when no authoritative guidance is cited.*

In addition, using the 3.85% depreciation rate results in an annual expense of $202.70. This is quite immaterial and further demonstrates that this recommendation is unwarranted."

Recommendation

Audit recommends that the Company and the Department of Energy Staff determine the prudence and appropriateness of including this cost as a component of Plant in Service.

Company Response

The audit issue identified appears to be from a prior rate case in which all issues were resolved through a global settlement agreement. There were no instances of this issue arising in this rate case, therefore the Company does not have any issues to respond to related to this audit issue.

Audit Comment

While Audit understands the Company comment, the issue is restated. The ratepayers should not pay for artwork. This was reviewed to ensure that the sample of plant additions tested during the last rate case, for which issues were identified, were addressed. Audit and the Department of Energy cannot review 100% of Plant in Service.

Audit Issue #28
FERC Form 1 does not Agree with the Filing

Background

Account #922 Administrative Expenses Transferred-Credit shows $(8,002,460) per the FERC Form 1 and the SAP year-end account balances.

Account #926 Employee Pensions and Benefits shows $3,697,502 per the FERC Form 1 and SAP year-end account balances.

Issue

FERC Form 1 Account 922 does not agree with the filing RR-2.10 which reflects $(8,501,412), a variance of $498,952. The Company indicated that the variance was "*due to the reversal of an entry to correct an unsettled WBS charge impacting regulatory net income.*"

FERC Form 1 Account 926 does not agree with the filing schedule RR-2.10, which sums to $4,053,502, or $356,000 higher than the FERC Form 1. In response to a request for clarification of the variances, the Company noted that the variance "*is due to a correction for pre-cap meter overheads which were double booked.*"

The Company further noted that "*The Company, along with our external auditors, determined to not reflect these adjustments in the FERC Form 1 to align with previously presented financial information in the APUC Form 10-K Annual Report and Granite State Electric standalone financial statements. The adjustments were correctly reflected in the Revenue Requirement.*"

Audit informed the Department of Energy staff to this and Data Request #11-14 was issued on October 5, 2023.

Recommendation

The Company should ensure that its presentation of the FERC Form 1 reflects true, actual account details.

Both of these accounts were also impacted by mismapping. See **Audit Issue #1**.

Company Response

As noted in the Audit Issue text above, the Company did provide a response to Department of Energy in DOE 11-14 identifying the complete list of entries identified after the December 31, 2022, financial records were closed that were not reflected in the FERC Form 1 but were presented correctly in the Company's revenue requirement filing in this proceeding. The Company addresses the financial statements in the response to Audit Issue #1.

Audit Comment

Below is the response provided to data request DoE 11-14:

Attachment DE 23-039 DOE 11-14

1) Capitalize 85% of physical inventory write off recorded

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
5	10921000	M&C-Inventory Diff	10920000	500495	(687,051)
1	10107000	CWIP	10107000	150110	687,051

Physical inventory adjustment was recorded in December 2022. The system did not capture the amount for capitalization. This was identified after year end as a manual adjustment needed in the preparation of the revenue requirement.

2) Correct over-accrual of capital invoices that were paid in 2022

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
1	10107000	CWIP	10107000	150110	(857,308)
2	10242000	Misc Accrued Liab		210300	857,308

Following the year end close, it was identified that certain capital accruals were accrued that had already been paid in the year. This was corrected manually in preparation of the revenue requirement.

3) Correct pre cap meter overheads double-booked

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
5	10926000	Benefits	10926000	500150	356,000
1	10107000	CWIP	10107000	150110	(356,000)

Overheads on pre capitalized meters were inadvertently recorded twice in 2022. This was identified following the year end close and was manually corrected in preparation of the revenue requirement.

4) Entry to correct regulatory net income

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
7	10182300	WBS ST Services	10182300	702xxx	(498,952)
1	10182300	Regulatory asset	10182300	171500	498,952

The SAP system is set up in a way that GAAP and regulatory (FERC) accounts can be recorded differently for each journal entry to allow for GAAP to FERC accounting differences. In reviewing the regulatory results, it was determined that certain regulatory entries were recorded incorrectly. This entry was manually corrected in preparation of the revenue requirement to align with the expectation that the Company would not have material differences between GAAP and FERC results.

5) Correct regulatory account settlements

Acct type	Regulatory Account	G/L Account2	Functional Area	GAAP (Natural) Account	Total
5	10920000	Other Operating Exp	10920000	505000	(18,143)
1	10107000	CWIP	10107000	150110	18,143

Similar to entry (4), as part of the Company's review of the regulatory results, the Company identified that certain settlements did not follow the correct accounting for regulatory reporting purposes. This was corrected in preparation of the revenue requirement.

Summary:	Dr / (Cr)
Net P&L Impact	(848,145)
Net CWIP Impact	(508,114)
Accruals Impact	857,308
Regulatory Asset Impact	498,952

Audit reinforces the stated issue, that the FERC Form 1 does not reflect the actual account balances in the reported accounts. It is understood that the Company and the External Auditors did not feel the need to ensure those reported accounts aligned with the SAP, as that would impact corporate level financial reporting. Refer to Audit Issue #1.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 4

Date Request Received: 7/21/23
Request No. DOE 4-48

Date of Response: 8/4/23
Respondent: Kristin Jardin
Daniel Dane

REQUEST:

Rent. Reference DOE 1-1.2, Tab RR-3.8. The Company's Rate Year rent expenses reflect test year rents escalated using the General Escalator.

			Interim Period (Annualized)	Rate Year	Rate Year	Rate Year
Description	**2022 Lease Expense**	**2023 Lease Expense**	**2022/2023**	**2023/2024**	**2024/2025**	**2025/2026**
Intercompany Rental Expense Granite State annual lease	59,236	62,960	61,098	64,501	65,932	67,327
Other Rental Expense	12,049	12,139	12,230	12,529	12,807	13,078
Total Rental Expense	**71,285**	**75,100**	**73,328**	**77,030**	**78,739**	**80,406**

a. Please list the properties included in the rent expense in the above table.

b. Please provide copies of the lease agreements for the properties.

RESPONSE:

a. In the preparation of this response, the Company identified that not all rental expenses were included in RR-3.8. Please see the following for the Company's corrected 2022 lease expenses, including locations:

		2022 Lease Expense
Intercompany Rental Expense Granite State - Londonderry building annual lease		59,236
Intercompany Rental Expense Granite State - Concord Training Center annual lease		123,893
Facilities leases:		
	E-Point - 130 Main St. Salem	26,125
	Cibarowski - 116 N. Main St. Concord	854
Total		210,108

b. Please see Attachment 23-039 DOE 4-47.1 for the Londonderry lease, Attachment 23-039 DOE 4-47.2 for the Training Center lease, Attachment 23-039 DOE 4-48.b.1 for the E-Point lease, and Attachment 23-039 DOE 4-48.b.2 for the Ciborowski lease.

LEASE

BETWEEN

E-Point, LLC
as Landlord

AND

Liberty Energy Utilities (New Hampshire) Corp.
as Tenant

July 16 , 2019

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LEASE

THIS LEASE (this "Lease") is made as of the 16th day of July, 2019 by and between E-Point, LLC, a New Hampshire limited liability company having an address of c/o INEX Properties, 40 Stark Street, Manchester, New Hampshire 03101 ("Landlord"), and Liberty Energy Utilities (New Hampshire) Corp., a Delaware corporation having an address at 15 Buttrick Road, Londonderry, New Hampshire 03053 ("Tenant"), for space in the buildings known as or located at 130 Main Street, Suite 101, Salem, New Hampshire 03079 (such buildings, together with the land upon which they are situated, being herein referred to as the "Building"). The following schedule (the "Schedule") sets forth certain basic terms of this Lease:

SCHEDULE

1. Premises:..A portion of the first floor of the Building consisting of approximately 2,345 rentable square feet of floor area as shown cross-hatched on the Floor Plan attached hereto as Exhibit A and incorporated herein by this reference.

2. Annual Base Rent: ....For Lease Months (as hereinafter defined) 1-2, $0.00 per year (annualized); for Lease Months 3-12, $30,485.00 per year (annualized); for Lease Months 13-24, $31,071.25 per year; for Lease Months 25-36 $31,657.50 per year; for Lease Months 37-48, $32,243.75 per year; and for Lease Months 49-60, $32,830.00 per year.

3. Monthly Base Rent: ....For Lease Months 1-2, $0.00 per Lease Month; for Lease Months 3-12, $2,540.42 per Lease Month; for Lease Months 13-24, $2,589.27 per Lease Month; for Lease Months 25-36, $2,638.13 per Lease Month; for Lease Months 37-48, $2,686.98 per Lease Month; and for Lease Months 49-60, $2,735.83 per Lease Month.

4. Tenant's Proportionate Share:...........10.71% (which is the percentage obtained by dividing (a) the number of rentable square feet of floor area in the Premises as stated above by (b) the 21,886 rentable square feet of floor area in the Building. Landlord and Tenant stipulate that the number of rentable square feet of floor area in the Premises and in the Building as set forth above is conclusive and shall be binding upon them.

5.	Estimated Expenses	$179,135 ($8.18 per rentable square feet of floor area in the Building.)
6.	Security Deposit:................................	None.
7.	Brokers:..	Mark Lacombe of PRM Enterprises dba INEX Properties who represents the Landlord and Hugo Overdeput of Colliers International NH who represents the Tenant.
8.	Commencement Date:.......................	August 1, 2019.
9.	Rent Commencement Date:	October 1, 2019.
10.	Expiration Date:	July 31, 2024.
11.	Parking Facility(s):............................	The parking lot located at 130 Main Street, Salem, New Hampshire.
12.	Project:	Collectively, the Parking Facilities and the Building.
13.	Address of Landlord:	E-Point, LLC c/o INEX Properties 40 Stark Street Manchester, New Hampshire 03101 Attention: Peter Milnes With a copy in like manner to: McLane Middleton, PA 900 Elm Street Manchester, New Hampshire 03101 Attention: William Zorn, Esq.
14.	Address of Tenant:	Liberty Energy Utilities (New Hampshire) Corp. 15 Buttrick Road Londonderry, New Hampshire 03053 Attention: Senior Manager, Facilities and Security With a copy in like manner to: Liberty Utilities 15 Buttrick Road Londonderry, New Hampshire 03053 Attention: Legal Department

1. **DEMISE AND TERM.** Landlord hereby leases to Tenant and Tenant leases from Landlord the premises (the "Premises") described in Item 1 of the Schedule, subject to the covenants and conditions set forth in this Lease, for a term (the "Term") commencing on the date (the "Commencement Date") described in Item 8 of the Schedule and expiring on the date (the "Expiration Date") described in Item 9 of the Schedule, unless terminated earlier as otherwise provided in this Lease.

Tenant shall have, as appurtenant to the Premises, the right to use in common with others entitled thereto, subject to reasonable rules and regulations from time to time made by Landlord: (a) the common lobbies, hallways, stairways of the Building serving the Premises in common with others; (b) the common walkways necessary to access to the Building, if any, (c) the common pipes, ducts, conduits, wires and appurtenant fixtures serving the Premises, and (d) subject to the terms of Section 19 of this Lease, the Parking Facility and the related parking easement area as shown on Exhibit C attached hereto.

Notwithstanding anything herein to the contrary, all the perimeter walls of the Premises except the interior surfaces thereof, any space in or adjacent to the Premises used for shafts, stacks, pipes, conduits, wires and appurtenant fixtures, fan rooms, ducts, electric or other utilities, sinks or other Building facilities, and the use thereof, are expressly excluded from the Premises and reserved to Landlord.

2. **RENT**

A. Definitions. For purposes of this Lease, the following terms shall have the following meanings:

(i) "Estimated Expenses" shall mean the amount set forth in Item 5 of the Schedule.

(ii) "Expenses" shall mean all expenses, costs and disbursements paid or incurred by Landlord in connection with the ownership, management, maintenance, operation, replacement and repair of the Project, including by way of example rather than limitation: (A) wages and salaries of all on-site employees at or below the grade of senior building manager engaged in the operation, maintenance or security of Project (together with Landlord's reasonable allocation of expenses of off-site employees at or below the grade of senior building manager who perform a portion of their services in connection with the operation, maintenance or security of the Project), including taxes, insurance and benefits relating thereto; (B) all supplies and materials used in the operation, maintenance, repair, replacement and security of the Project; (C) to the extent such costs actually reduce the normal operating costs of the Project (including all utility costs), costs for capital improvements made to the Project, as amortized using a commercially reasonable interest rate over the time period reasonably estimated by Landlord in accordance with generally acceptable accounting principles consistently applied to recover the costs thereof, as well the cost of capital improvements made in order to comply with any federal, state or local law, ordinance, rule or regulation or court order, governmental directive or governmental order hereafter promulgated by any governmental authority or any interpretation hereafter rendered with respect to any existing federal, state or local law, ordinance, rule or regulation, court order, governmental directive or governmental order, as amortized using a commercially reasonable interest rate over the useful economic life of such improvements as determined by Landlord in its reasonable discretion in accordance with generally accepted accounting principles consistently applied; (D) costs of all utilities, except the cost of utilities reimbursable to Landlord by the Building's tenants other than pursuant to a provision similar to Section 2.B(ii) below; (E) insurance expenses including deductible reimbursement; (F) repairs, replacements and general maintenance of the Project, including, without limitation, the repaving and resealing of the Parking Facilities; (G) costs with respect to the management office for the Building; (H) service, maintenance and management contracts for the operation, maintenance, management, repair, replacement or security of the Project; (I) legal, rent collection, accounting, tax preparation & filing and other professional fees with respect to the operation and management of the Project, exclusive of legal expenses of negotiating leases; and (J) Taxes (as hereinafter defined). Expenses shall not include: (a) the cost of repairs or other work occasioned by any insured casualty or cause insured against or which reasonably should have been insured against by Landlord, or occasioned by the exercise of the right of eminent domain; (b) leasing commissions marketing, advertising and promotional expenditures, the cost to rent and operate a management office in the Building, accountants', consultants', auditors or attorneys' fees, costs and disbursements and other expenses incurred in connection with negotiations or disputes with other tenants or prospective tenants or other occupants; (c) costs or expenses associated with the enforcement of any leases or the defense of Landlord's title to or interest in the Project or any part thereof; (d) costs incurred by Landlord in connection with construction of the Building, the Parking Facility, and any related facilities, the correction of defects in construction of the Building; (e) salaries of any employees above Senior Property Manager level; (f) costs (including permit, licenses and inspection fees) incurred in renovating or otherwise improving or decorating, painting, or redecorating the Building or space for other tenants or other occupants or vacant space; (g) depreciation and amortization; (h) costs incurred due to a breach by Landlord or any other tenant of the terms and conditions of any lease; (i) overhead and profit increment paid to subsidiaries or affiliates of Landlord for management or other services on or to the Building or for supplies, utilities or other materials, to the extent that the costs of such services, supplies, utilities or materials exceed the reasonable costs that would have been paid had the services, supplies or materials been provided by unaffiliated parties on a reasonable basis without taking into effect volume discounts or rebates offered to Landlord as a portfolio purchaser; (j) costs incurred by Landlord in connection with any financing affecting the Project or Landlord's interest therein; (k) interest on debt or amortization payments on any mortgage or deeds of trust or any other borrowings and any ground rent; (l) ground rents or rentals payable by Landlord pursuant to any over-lease; (m) any compensation paid to clerks, attendants or other persons in commercial concessions operated by Landlord; (n) costs incurred in managing or operating any "pay for" parking facilities located around the Project; (o) expenses resulting from the negligence of Landlord; (p) any fines or fees for Landlord's failure to comply with governmental, quasi-governmental, or regulatory agencies' rules and regulations; (q) legal, accounting and other expenses related to Landlord's financing, re-financing, mortgaging or selling the Project; (r) any Taxes not payable under Section 2(a)(v) hereunder; (s) costs for sculpture, decorations, paintings or other objects of art in excess of amounts typically spent for such items in office buildings of comparable quality in the competitive vicinity of the Building; (t) costs associated with any political, charitable or civic contribution or donation; (u) costs of items considered capital repairs, replacements, improvements and equipment under generally accepted accounting principles, except as permitted in (C) above; (v) items, utilities and services for which Tenant or other tenants reimburse Landlord or pay third parties or that Landlord provides selectively to one or more tenants of the Building other than Tenant without reimbursement; (w) costs incurred to test, survey, cleanup, contain, abate, remove, or otherwise remedy hazardous materials, conditions or asbestos-containing materials from the Project; or (x) any insurance policy "deductible" in excess of those customarily carried on similar buildings in the metropolitan area in which the Project is located. Expenses shall be determined on a cash or accrual basis, as Landlord may elect, but such basis shall be consistently applied throughout the Term.

(iii) "Operating Year" shall mean each twelve (12) month period commencing on January 1, 2019 and each anniversary of January 1, 2019 that occurs during Term.

(iv) "Rent" shall mean Base Rent, Adjustment Rent and any other sums or charges required to be paid by Tenant under this Lease.

(v) "Taxes" shall mean all taxes, assessments and fees levied upon the Project, the property of Landlord located therein or the rents collected therefrom, by any governmental entity based upon the ownership, leasing, renting or operation of the Project, including all costs and expenses of protesting any such taxes, assessments or fees but only to the extent of the deduction or abatement achieved by such protest. Taxes shall not include any net income, capital stock, succession, transfer, franchise, gift, estate or inheritance taxes; provided, however, if, at any time during the Term, a tax or excise on income is levied or assessed by any governmental entity, in lieu of or as a substitute for, in whole or in part, real estate taxes or other ad valorem taxes, such tax or excise shall constitute and be included in Taxes.

For the purposes of determining Taxes for any given Operating Year, the amount to be included for such Operating Year from (a) special assessments payable in installments shall be the amount of the installments (and any interest) due and payable during such Operating Year, and (b) all other Taxes shall be the amount assessed for such Operating Year.

(vi) "Tenant's Proportionate Share" shall mean the percentage set forth in Item 4 of the Schedule.

B. Components of Rent. Tenant agrees to pay the following amounts to Landlord at the office of the Building or at such other place as Landlord designates, provided that upon request of Tenant, Landlord shall provide to Tenant, Landlord's account information and electronic funds transfer instructions so that Tenant can pay all amounts due hereunder by electronic funds transfer of immediately available federal funds (provided that Tenant shall be responsible for any actual third party costs required to deliver such amounts by electronic funds transfer):

(i) Base rent ("Base Rent") to be paid in monthly installments in the amounts and for the Lease Months set forth in Item 3 of the Schedule in advance on or before the first day of each calendar month of the Term, except that the first monthly installment of Base Rent shall be payable simultaneously with the execution and delivery of this Lease by Tenant; thereafter, Base Rent shall be payable on the first day of each calendar month beginning on the first day of the second full calendar month of the Term (subject, however, to the Base Rent credit provided in this Lease). The monthly Base Rent for any partial calendar month at the beginning or end of the Term shall equal the product of 1/365 of the annual Base Rent in effect during the partial calendar month and the number of days in the partial calendar month.

(ii) Adjustment rent ("Adjustment Rent") for each Operating Year or partial Operating Year during the Term in an amount equal to Tenant's Proportionate Share multiplied by the amount equal to the Expenses for such Operating Year or partial Operating Year. Prior to each Operating Year, Landlord shall estimate the amount of Adjustment Rent due for such Operating Year, and Tenant shall pay Landlord one-twelfth of such estimate on the first day of each calendar month during such Operating Year. Such estimate may be revised by Landlord whenever Landlord obtains information relevant to making such estimate more accurate, but Tenant shall have at least thirty (30) days advance notice to deliver the updated monthly amount of Adjustment Rent. After the end of each Operating Year, Landlord shall deliver to Tenant a report setting forth the actual Expenses for such Operating Year, which report shall consist of a Quick Book (or comparable) report by category with each invoice noted, and a statement of the amount of Adjustment Rent that Tenant has paid and is payable for such Operating Year. Within two (2) Business Days' advance notice from Tenant, Landlord shall provide access to back-up documentation, invoices, and receipts supporting the Expenses at Landlord's office. Within thirty (30) days after receipt of such report and statement, Tenant shall pay to Landlord the amount of Adjustment Rent due for such Operating Year minus any payments of Adjustment Rent made by Tenant for such Operating Year. If Tenant's estimated payments of Adjustment Rent exceed the amount due Landlord for such Operating Year, Landlord shall apply such excess as a credit against Tenant's other obligations under this Lease or promptly refund such excess to Tenant if the Term has already expired, provided Tenant is not then in default hereunder beyond any applicable notice and cure period, in either case without interest to Tenant.

C. Payment of Rent. The following provisions shall govern the payment of Rent; (i) if this Lease commences or ends on a day other than the first day or last day of a calendar month, respectively, the Rent for the calendar month in which this Lease so begins or ends shall be prorated and the monthly installments shall be adjusted accordingly; (ii) all Rent shall be paid to Landlord without offset or deduction (except as otherwise provided in this Lease), and the covenant to pay Rent shall be independent of every other covenant in this Lease; (iii) if, during all or any portion of an Operating Year the Building is not fully occupied and rented, and Landlord provides trash removal services or utility services which serve both the vacant area of the building and the Premises, the Landlord may adjust the Tenant's share of the expense for those services in proportion to the users of such services, after accounting for the base charge of providing the utility service and any nominal consumption charge attributable to the vacant area (presumably to provide minimal heat), in order to receive full reimbursement for any such charge(s); (iv) any sum due from Tenant to Landlord which is not paid when due shall bear interest from the date due until the date paid at the annual rate of eighteen percent (18%) per annum, but in no event higher than the maximum rate permitted by law (the "Default Rate"), and, in addition, Tenant shall pay Landlord a late charge for any Rent payment which is paid more than five (5) days after its due date equal to five percent (5%) of such payment, provided that such late charge shall not be due and payable with respect to the first late payment Tenant makes in a calendar year; (v) if changes are made to this Lease or to the actual area of the Premises or the Building changing the number of square feet contained in the Premises or in the Building, Landlord shall make an appropriate adjustment to Tenant's Proportionate Share (such changes shall not result from a re-measurement of the Premises or the Building given that the parties have stipulated to the area of the Premises and Building as set forth herein); (vi) Tenant shall have the right to inspect or have its appointed accountant or other consultant inspect or otherwise review Landlord's accounting records relative to Expenses during normal business hours at any time within ninety (90) days following the furnishing to Tenant of the report setting forth the actual

Expenses for an Operating Year; and unless Tenant shall take written exception to any item in any such report within such 90 day period, such report shall be considered as final and accepted by Tenant; (vii) in the event of the termination of this Lease prior to the determination of any Adjustment Rent, Tenant's agreement to pay any such sums and Landlord's obligation to refund any such sums (provided Tenant is not in default hereunder beyond any applicable notice and cure period) shall survive the termination of this Lease; and if this Lease ends on a day other than the last day of a Operating Year, then the Expenses to be used to determine Adjustment Rent for such partial Operating Year shall be the amount estimated by the Landlord for the then current year (see 2.B.ii) multiplied by a fraction, the numerator of which shall be the number of days during such partial Operating Year and the denominator of which shall be 365; (viii) intentionally omitted; (ix) each amount owed to Landlord under this Lease which is not a regularly scheduled payment of Base Rent or Adjustment Rent shall be due within thirty (30) days after Tenant's receipt of an invoice and reasonable supporting documentation therefor; and (x) if Landlord fails to give Tenant an estimate of Adjustment Rent prior to the beginning of any Operating Year, Tenant shall continue to pay Adjustment Rent at the rate for the previous Operating Year until Landlord delivers such estimate. In the event Tenant's audit under (vi) above discloses any discrepancy, Landlord and Tenant will use reasonable efforts to resolve the dispute and make an appropriate adjustment, failing which, they will submit any such dispute to arbitration pursuant to the rules and under the jurisdiction of the American Arbitration Association in the metropolitan area where the Premises is located. The decision rendered in such arbitration will be final, binding and non-appealable. The expenses of arbitration, other than individual legal and accounting expenses, which will be the respective parties' responsibility, will be divided equally between the parties. If, by agreement or as a result of an arbitration decision, it is determined that Expenses claimed by the Landlord exceed the actual Expenses by five percent (5%) or more, the actual, reasonable hourly costs to Tenant of Tenant's audit (including arbitration fees, legal and accounting costs if any) will be reimbursed by Landlord. In such case, if Tenant will have utilized a contingent fee auditor, Landlord will be responsible for only the reasonable hourly fee of such auditor. If, by agreement or as a result of an arbitration decision, it is determined that Expenses claimed by the Landlord exceed the actual Expenses by less than five percent (5%), the arbitration fees and legal and accounting costs actually incurred by Landlord in connection with such audit shall be reimbursed by Tenant.

3. **USE.** Tenant agrees that it shall occupy and use the Premises only as a Customer Center & Office (the "Permitted Use") and for no other purposes. Tenant shall, at its own expense, comply with all federal, state and municipal laws, ordinances and regulations and all covenants, conditions and restrictions of record applicable to Tenant's business operations at the Premises. Without limiting the foregoing, Tenant shall not cause, nor permit, any hazardous or toxic substances to be brought upon, produced, stored, used, discharged or disposed of in, on or about the Premises without the prior written consent of Landlord (except for normal quantities of office and cleaning supplies and other materials typically used in Tenant's customer center and office locations, which shall not require the consent of Landlord) and then only in compliance with all applicable environmental laws. Notwithstanding anything herein to the contrary, Tenant, and/or its agents, employees, contractors, or invitees ("Tenant Parties"), shall be liable only for hazardous, toxic, controlled, dangerous, or radioactive substances, materials or wastes regulated under applicable laws ("Hazardous Materials") that Tenant or the Tenant Parties introduce onto the Premises or generate therefrom ("Tenant Hazardous Materials"). Neither Tenant nor Tenant Parties will have any responsibility or liability whatsoever for, resulting from, or in any way related to (i) any Hazardous Materials, at, in, on, under, emanating from or in connection with the

Premises whatsoever (except for Tenant Hazardous Materials); (ii) the investigation, remediation, cleanup, closure, and/or removal of any structures or devices existing at the Premises which were used on connection with Hazardous Materials, irrespective of Tenant's or the Tenant Parties' use thereof; (iii) the acts or omissions of Landlord, any other tenant or subtenant, or any respective agents, employees, invitees, contractors or subcontractors; (iv) any permits, licenses, authorization, or approvals, except for those which Tenant or any of the Tenant Parties must be law obtain in its or their own name for their use of the Premises; or (v) minimal losses of oil, petroleum, or other substances contained in (but not transported by) vehicles which enter the Project or any roads, parking areas, or other areas used in connection therewith. Landlord will indemnify and hold harmless Tenant and Tenant Parties from and against any and all losses, costs, expenses, damages, liability, claims and demands arising or resulting from, or connected with, any matters covered in (i) through (v) above (except to the extent the foregoing arise from Tenant Hazardous Materials or are caused by the negligence of Tenant or Tenant Parties).

4. **CONDITION OF PREMISES.** Except as expressly provided in this Lease, Tenant's taking possession of the Premises shall be conclusive evidence that the Premises were in good order and satisfactory condition when Tenant took possession. No representation regarding the condition of the Premises or the Building, have been made by or on behalf of Landlord or relied upon by Tenant, and no agreement of Landlord to alter, remodel, decorate, clean or improve the Premises or the Building (or to provide Tenant with any credit or allowance for the same), except as stated below, in Section 27 entitled Landlord Improvements, in Section 8 entitled Maintenance and Repair – the later solely with respect to the HVAC system, or otherwise in this Lease. Landlord represents and warrants that as of the Commencement Date, the Premises, including without limitation, all structural portions and utility systems including the electrical, plumbing and HVAC systems (i) will be free of latent defects, (ii) will be in good working order and repair, (iii) will comply with all applicable codes, regulations, rules, laws, ordinances and other governmental regulations or requirements applicable to the Premises, and (iv) the heating, ventilation and air conditioning systems, electrical system, plumbing system, fire safety/suppression system in each case serving the Premises are of sufficient capacity for the intended office use and are in good condition and repair. If any part of the Premises is found not to be in compliance with the foregoing warranties, then Landlord shall correct the noncompliance promptly at its own expense (and without reimbursement from Tenant) after receipt of written notice from Tenant. Notwithstanding the foregoing, Tenant shall be responsible for any required changes to the systems serving the Premises to the extent such changes are triggered by Tenant's Initial Alterations or subsequent reconfiguration of the Premises.

5. **SERVICES AND UTILITIES.**

A. <u>Landlord's Services</u>. Landlord shall furnish the following services ("Landlord's Services"): (i) heating and air conditioning to provide a temperature condition required, in Landlord's reasonable judgment, for comfortable occupancy of the Premises under normal office business operations, Mondays through Fridays, inclusive, from 7:00 A.M. to 7:00 P.M., Saturdays from 9:00 A.M. to 2:00 P.M., Sundays and Federal and State of New Hampshire holidays ("Holidays") excepted (hereinafter referred to as "Normal Business Hours"); (ii) water and associated sewer or septic at those points of supply provided for general domestic use of tenants of the Building; (iii) electrical current for equipment that does not require more than 110 volts and whose electrical energy consumption does not exceed normal office usage. All costs and expenses incurred by Landlord in connection with furnishing Landlord's Services shall be included as part of Expenses pursuant to Section 2 above, except for services provided to Tenant that are separately metered (i.e. electricity for light, outlets & air conditioning) or otherwise accounted for (it being understood that electric service is currently and shall remain separately metered), in which case the Tenant shall pay the vendor(s) directly for such service(s) as they become due.

B. Special and Additional Usage Tenant shall be responsible for all special electrical, cooling and ventilating needs created by Tenant's telephone equipment, computers, electronic data processing equipment and other similar equipment or uses. In addition, Tenant's use of electricity shall at no time exceed the capacity of the service to the Premises or the electrical risers or wiring installation. Tenant shall be responsible for all water and sewer charges beyond the general domestic and office use provided to the Building.

Notwithstanding anything herein to the contrary, Landlord shall furnish heating during times other than Normal Business Hours provided that notice requesting such service is delivered to Landlord's managing agent before noon on any business weekday when such service is required for that evening and by noon of the immediately preceding business weekday when such service is required for after 2:00 p.m. on a Saturday or for any time on a Sunday or Holiday. Landlord's cost of supplying such additional heating shall be paid by Tenant within thirty (30) days of receipt of an invoice, which invoice shall cite the specific days and times of the requested additional heating. Landlord hereby acknowledges that the current charge for non-Normal Business Hours heating is $25.00 per hour (in two (2) hour minimum increments). Such charge is based upon Landlord's reasonable estimate of the cost to Landlord of providing heating during non-Normal Business Hours, including equipment maintenance and wear and tear associated with such non-Normal Business Hours Use. Such charge may be increased by Landlord from time to time (but no more frequently than once per calendar year and not prior to January 1, 2020) based upon such reasonable estimate of the cost to Landlord of providing such non-Normal Business Hours heating.

C. Cooperation; Payment of Charges. Tenant agrees to cooperate fully at all times with Landlord and to abide by all reasonable regulations and requirements which Landlord may prescribe for the use of the above utilities and services, provided that in the event of any conflict between such regulations and requirements and the terms of this Lease, the terms of this Lease shall prevail. Tenant agrees to pay any charge imposed by Landlord pursuant to Section 5.B above and any failure to pay any excess costs as described above shall constitute a breach of the obligation to pay Rent under this Lease and shall entitle Landlord to the rights herein granted for such breach and shall entitle Landlord to immediately discontinue providing such additional or special service. Tenant's use of electricity shall at no time exceed the capacity of the service to the Premises or the electrical risers or wiring installation.

D. Failure, Stoppage or Interruption of Service; No Release from Obligations. Except as provided below, Landlord shall not be liable for, and Tenant shall not be entitled to, any abatement or reduction of Rent by reason of Landlord's failure to furnish any of the foregoing utilities or services when such failure is caused by accident, breakage, repairs, riots, strikes, lockouts or other labor disturbance or labor dispute of any character, governmental regulation, moratorium or other governmental action, inability by exercise of reasonable diligence to obtain electricity, water or fuel, or by any other cause beyond Landlord's reasonable control or for stoppages or interruptions of any such utilities or services for the purpose of making necessary repairs or improvements. Failure, stoppage or interruption of any such utility or service shall not be construed as an actual or constructive eviction or as a partial eviction against Tenant, or release Tenant from the prompt and punctual performance by Tenant of the covenants contained herein or operate to abate Rent. Notwithstanding anything herein to the contrary, in the event that electrical power, water or gas service or other utility services are interrupted as a result of an act or omission of Landlord or its agents, employees or representatives, to the extent that Tenant's operations at the Premises are substantially impacted, as reasonably determined by Tenant, ("Service Interruption") and such Service Interruption continues for more than two (2) business days, Base Rent shall abate until such time as the Service Interruption is corrected.

E. Limitation and Unavailability of Service. Anything hereinabove to the contrary notwithstanding, Landlord and Tenant agree that Landlord's obligation to furnish heat, electricity, air conditioning and/or water to the Premises shall be subject to and limited by all laws, rules, and regulations of any governmental authority affecting the supply, distribution, availability, conservation or consumption of energy, including, but not limited to, heat, electricity, gas, oil and/or water. Landlord shall abide by all such governmental laws, rules and regulations and, in so doing, Landlord shall not be in default in any manner whatsoever under the terms of this Lease, and Landlord's compliance therewith shall not affect in any manner whatsoever Tenant's obligation to pay the full Rent set forth in this Lease.

F. Telephone. Landlord makes no representations or warranties with respect to the capacity, suitability or design of the telephone risers, if any, the telephone room, if any, or the telephone lines. If there is more than one tenant on a floor, Landlord shall allocate hookups to the telephone room, if any, based on the proportion of rentable square feet that each tenant occupies on the floor. The installation and hook-up of telephone lines by Tenant shall be subject to all of the terms and conditions of this Lease, including, without limitation, Section 9 of this Lease. Except to the extent caused by any act or omission of Landlord or its agents, employees, or contractors, Landlord shall not be liable for, and Tenant waives all claims with respect to, any damages or losses sustained by Tenant or by any occupant of the Premises, including, without limitation, any compensatory, property or consequential damages, resulting from the operation or maintenance of the telephone risers, if any, the telephone rooms, if any, and the telephone lines, including, without limitation, (i) any damage to Tenant's telephone lines, telephones or other equipment connected to the telephone lines, or (ii) interruption or failure of, or interference with, telephone or other service coming through the telephone lines to the Premises.

G. Access. Subject to the terms of this Lease, Tenant will be provided access to the Premises twenty-four (24) hours per day, seven (7) days per week. If such access is unavailable due to force majeure as described in Section 25.I or any other reason beyond Landlord's control, Landlord shall not be in default under this Section 5.G.

H. Electric & Natural Gas Service Providers. Landlord has advised Tenant that presently Liberty Utilities and First Point Power (the "Electric Service Providers") are the electric utility companies selected by Landlord to provide electricity service for the Building and Unitil (the "Natural Gas Service Provider") is the natural gas utility company selected by Landlord to provide natural gas service for the Building. Notwithstanding the foregoing, Landlord reserves the right at any time and from time to time before or during the Term to either contract for electric and/or natural gas services from a different company or companies providing electricity or natural gas services (each such company shall hereinafter be referred to as an "Alternative Service Provider") or continue to contract for electricity or natural gas services from the Electric and Natural Gas Service Providers. Tenant shall cooperate with Landlord, the Electric and Natural Gas Service Providers and any Alternative Service Provider(s) at all times and, as reasonably necessary, shall allow Landlord, the Electric and Natural Gas Service Providers and any Alternative Service Provider(s) with reasonable access to the Building's electric and natural gas lines, feeders, risers, wiring, piping and other machinery within the Premises.

6. **RULES AND REGULATIONS.** Tenant shall observe and comply and shall cause its subtenants, assignees, invitees, employees, contractors and agents to observe and comply, with the rules and regulations listed on Exhibit B attached hereto and incorporated herein by this reference and with such reasonable modifications and additions thereto as Landlord may make from time to time, provided that in the event of any conflict between the terms of this Lease and the terms of such rules and regulations, the terms of this Lease shall prevail. Landlord shall not be liable for failure of any person to obey such rules and regulations. Landlord shall not be obligated to enforce such rules and regulations against any person, and the failure of Landlord to enforce any such rules and regulations shall not constitute a waiver thereof or relieve Tenant from compliance therewith.

7. **CERTAIN RIGHTS RESERVED TO LANDLORD.** Landlord reserves the following rights, each of which Landlord may exercise without notice to Tenant and without liability to Tenant, and the exercise of any such rights shall not be deemed to constitute an eviction or disturbance of Tenant's use or possession of the Premises and shall not give rise to any claim for set-off or abatement of rent or any other claim: (a) to change the name or street address of the Building or the suite number of the Premises; (b) to install, affix and maintain any and all signs on the exterior or interior of the Building (other than signs visible solely from the interior Premises); (c) provided Tenant's use of or access to the Premises is not materially or unreasonably impacted, to make repairs, decorations, alterations, additions, or improvements, whether structural or otherwise, in and about the Building, and for such purposes to enter upon the Premises, temporarily close doors, corridors and other areas in the Building and interrupt or temporarily suspend services or use of common areas, and Tenant agrees to pay Landlord for overtime and similar expenses incurred if such work is done other than during ordinary business hours at Tenant's request; (d) to retain at all times, and to use in appropriate instances, keys to all doors within and into the Premises; (e) to grant to any person or to reserve unto itself the exclusive right to conduct any business or render any service in the Building (except that the foregoing shall not prohibit Tenant from conducting its business within the Premises consistent with the Permitted Use or engaging any vendors or contractors to provide services to Tenant at the Premises); (f) to show or inspect the Premises at reasonable times during Tenant's normal business hours and upon at least twenty-four (24) hours prior advance notice to Tenant (except in the event of an emergency, Landlord may access the Premises at any time and without notice); (g) to install, use and maintain in and through the Premises, pipes, conduits, wires and ducts serving the Building, provided that such installation, use and maintenance does not unreasonably interfere with Tenant's use of the Premises; and (h) to take any other action which Landlord deems reasonable in connection with the operation, maintenance or preservation of the Project. During any entry upon the Premises, Landlord and its agents, employees, and contractors shall

not unreasonably interfere with Tenant's ongoing business operations at the Premises, and Tenant shall have the right to require that an employee or other representative of Tenant accompany Landlord or Landlord's agent, employee, or contractor during any entry upon the Premises.

8. **MAINTENANCE AND REPAIRS.** Except as specifically herein otherwise provided, Tenant agrees it will, during the Term of this Lease, make all repairs and alterations to the property Tenant is required to maintain, as hereinafter set forth, which may be necessary to maintain the same in good repair and condition or which may be required by any laws, ordinances, regulations, or requirements of any public authorities having jurisdiction. Tenant agrees that the entire Premises, including its entranceways, common areas and accessways are designated as non-smoking. The property which Tenant is required to maintain, repair, and, as necessary, replace pursuant to this Section is the leased Premises and every part thereof, including, without limitation, the store front and exterior and interior portions of all doors, windows, plate glass and showcases surrounding the leased Premises, interior walls, floors, ceilings, signs (including Tenant's exterior signage where permitted) and appliances and equipment within the Premises (including without limitation, the heating, hot water, electrical, plumbing, ventilation and air conditioning systems to the extent such systems exclusively serve the Premises. Tenant further agrees that it will, during the Term of this Lease, obtain and keep in force a maintenance contract on the HVAC unit that exclusively serves the Premises with a licensed, independent HVAC service company that is reasonably approved by Landlord. Tenant agrees that said maintenance contract shall not be cancelled without prior notice to Landlord. Provided Tenant, during the Term of this Lease, obtains and keeps in force such maintenance and service contract and provides copies of the required quarterly maintenance service records to Landlord upon written request, then Landlord agrees to be responsible for all additional repairs and/or replacement of the HVAC unit and system (such replacement shall be at the determination of such independent HVAC service company as to when the useful life of the unit has been met) after the Tenant has first paid $1,000 per (calendar) year for maintenance & repairs of such HVAC unit and system, including the cost of a required service contract with a third-party vendor. Landlord is responsible for providing hot water from the Building's boiler to the HVAC unit exclusively serving the Premises, where the Tenant then assumes its responsibility. Notwithstanding anything contained in this Section 8 to the contrary but subject to the provision above regarding the allocation of repair and replacement responsibility for the HVAC unit that exclusively serves the Premises, Landlord will be responsible to make any repairs, alterations and/or modifications to the Premises which would be deemed a capital expenditure under generally accepted accounting principles.

Tenant shall at Tenant's expense, keep and maintain the leased Premises and any part and portion in good order and condition throughout the Term of this Lease. Tenant specifically agrees to replace all glass damaged with glass of at least the same kind and quality or, of a higher kind or quality required if by statute or ordinance. Tenant further agrees that the leased Premises shall be kept in a clean, sanitary and safe condition in accordance with the laws of the State of New Hampshire, and ordinances of the Town and County in which the Premises are situated, and in accordance with all directions, rules and regulations of the Health Officer, Fire Marshall, Building Inspector and other proper officers of the governmental agencies having jurisdiction thereover. Tenant shall not permit or commit any waste. Tenant agrees to utilize chair pads under all rolling chairs to protect interior carpet. The Tenant agrees that if at any time the Landlord determines said Premises are not properly maintained or cleaned and Tenant has not commenced such maintenance or cleaning within thirty (30) days after Tenant's receipt of notice thereof from Landlord or does not thereafter diligently pursue such maintenance or cleaning to completion, the Landlord, at the Tenant's expense, shall have such work performed in a manner satisfactory to it.

Without limiting the generality of the foregoing, Tenant, at its expense, shall cause the Premises to be cleaned (including, without limitation, removal of trash from the Premises) on a regular basis consistent with the cleaning specifications for Tenant's other customer center and office locations. Landlord shall perform any maintenance or make any repairs to the Building as Landlord shall desire or deem necessary for the safety, operation or preservation of the Building, or as Landlord may be required or requested to do by any governmental authority or by the order or decree of any court or by any other proper authority.

Except as otherwise provided in this Lease and subject to Tenant's obligations set forth in the preceding paragraphs of Section 8 or elsewhere in this Lease, Landlord shall keep and maintain or cause to be kept and maintained the structural components of the Building (including, without limitation, the roof and the roof membrane), all common areas of the Building, all Building systems in a first-class, neat, safe and orderly condition in compliance with all applicable governmental rules, regulations, laws, and ordinances and shall make all necessary repairs thereto. Except as otherwise provided in this Lease, the cost of all such maintenance and repairs shall be borne by Landlord and shall be included as part of Expenses.

9. ALTERATIONS.

A. Requirements. Tenant shall not make any alteration, improvement or addition to the Premises (collectively an "Alteration") without the prior written consent of Landlord, provided that non-structural Alterations that do not affect the building systems of the Building and cost less than Twenty Thousand and 00/100 Dollars ($20,000.00) shall not require the consent of Landlord. In the event Tenant proposes to make any Alteration that requires Landlord's consent, Tenant shall, prior to commencing such alteration, submit to Landlord for prior written approval: (i) detailed plans and specifications; (ii) the names and addresses for all contractors that will perform the Alterations; (iii) all necessary permits evidencing compliance with all applicable governmental rules, regulations and requirements; and (iv) certificates of insurance from the contractors in amounts of at least $1,000,000 in general commercial liability coverage, naming Landlord and any other parties designated by Landlord as additional insureds. Neither approval of the plans and specifications nor supervision of the Alteration by Landlord shall constitute a representation or warranty by Landlord as to the accuracy, adequacy, sufficiency or propriety of such plans and specifications or the quality of workmanship or the compliance of such alteration with applicable law. Tenant shall pay the entire cost of the Alteration. Each Alteration shall be performed in a good and workmanlike manner, in accordance with the plans and specifications approved by Landlord, and shall meet or exceed the standards for construction and quality of materials established by Landlord for the Building. In addition, each Alteration shall be performed in compliance with all applicable governmental laws, regulations and requirements. Each Alteration shall be performed in harmony with Landlord's employees, contractors and other tenants. Each Alteration, whether temporary or permanent in character, made by Landlord or Tenant in or upon the Premises (excepting only Tenant's furniture, equipment and trade fixtures) shall become Landlord's property and shall remain upon the Premises at the expiration or termination of this Lease without compensation to

Tenant; provided, however, that as to those Alterations that require Landlord's consent, Landlord shall have the right to require Tenant to remove such Alteration prior to Tenant's surrender of the Premises at Tenant's sole cost and expense by notifying Tenant in writing of such removal requirement at the time the Landlord consents to such Alteration. Landlord hereby consents to the initial Alterations as further described in Exhibit D attached hereto, and Tenant shall not be required to remove such initial Alterations from the Premises at the time Tenant surrenders the Premises to Landlord.

Notwithstanding anything in this Lease to the contrary, as between Landlord and Tenant, (a.) Tenant shall bear the risk of complying with Title III of the Americans With Disabilities Act of 1990, any state laws governing handicapped access or architectural barriers, and all rules, regulations, and guidelines promulgated under such laws, as amended from time to time (the "Disabilities Acts") in the Premises, and (b.) Landlord shall bear the risk of complying with the Disabilities Acts in the common areas of the Building and Project, other than compliance that is necessitated by the use of the Premises by Tenant for other than the Permitted Use or as a result of any Alterations made by Tenant (which risk and responsibility shall be borne by Tenant).

B. Liens. Upon completion of any Alteration, Tenant shall promptly furnish Landlord with sworn owner's and contractors statements and full and final waivers of lien covering all labor and materials included in such alteration. Tenant shall not permit any mechanic's lien to be filed against the Building, or any part thereof, arising out of any alteration performed, or alleged to have been performed, by or on behalf of Tenant. If any such lien is filed, Tenant shall within thirty (30) days after Tenant's receipt of written notice thereof have such lien released of record or deliver to Landlord a bond in form, amount, and issued by a surety satisfactory to Landlord, indemnifying Landlord against all costs and liabilities resulting from such lien and the foreclosure or attempted foreclosure thereof. If Tenant fails to have such lien so released or to deliver such bond to Landlord within such thirty (30) day period, Landlord, without investigating the validity of such lien, may pay or discharge the same; and Tenant shall reimburse Landlord upon demand for the amount so paid by Landlord, including Landlord's expenses and attorneys' fees.

10. **INSURANCE.**

A. Tenant's Insurance. Tenant, at its expense, shall maintain at all times, on a primary basis, during the Term the following insurance policies: (a) all risk or equivalent special form coverage insuring the full replacement cost of all property owned or used by Tenant and located in the Premises; and (b) commercial general liability insurance, contractual liability insurance, including Tenant's indemnity obligations under Section 11B. of this Lease, and property damage insurance against any and all claims, including all legal liability to the extent insurable and imposed upon Tenant and all court costs and attorneys' and expenses, arising out of or connected with the possession, use, leasing, operation, maintenance or condition of the Premises or use of the Project by Tenant, its employees, agents, invitees, licensees or any other person accessing the Project in connection with the Tenant's lease of the Premises, with limits not less than $2,000,000.00 combined single limit for personal injury, sickness or death or for damage to or destruction of property for any one occurrence, on a so-called "occurrence form basis." All insurance provided for herein from Tenant shall be obtained under valid and enforceable policies (the "Policies" or in the singular, the "Policy"), and shall be issued by one or more other domestic primary insurer(s) having a general policy rating of A or better and a financial class of VIII or better by A.M. Best Company, Inc. (or if a rating of A.M. Best Company Inc. is no longer available, a similar rating from a similar or successor service). All insurers providing insurance required by this Lease shall be authorized to issue insurance in the state in which the Premises is located. In addition, the policies shall name Landlord and any other parties designated by Landlord as additional insureds and shall require at least thirty (30) days' prior written notice to Landlord and such other parties designated by Landlord of termination or modification and shall be primary and not contributory. Prior to the Commencement Date and within fifteen (15) days prior to the expiration of each such policy, Tenant shall deliver to Landlord a Certificate of Insurance (in form ACORD 27 or its equivalent) for each such policy evidencing the foregoing insurance or renewal thereof, as the case may be.

If Tenant fails to maintain and deliver to Landlord a certificate of insurance required by this Lease or if Landlord receives a copy of a notice of cancellation of any insurance which is the responsibility of Tenant to maintain, upon ten (10) days prior written notice to Tenant, Landlord may procure such insurance at Tenant's sole cost and expense. The amount so paid will constitute Additional Rent payable by Tenant at the next rental payment date. Payment of premiums by Landlord will not be deemed a waiver or release by Landlord of the default by Tenant in failing to pay the same or of any action which Landlord may take hereunder as a result of such default.

Tenant shall comply with all insurance requirements under such Policy or Policies and shall not bring or keep or permit to be brought or kept any article upon any of the Premises or cause or permit any condition to exist thereon which would be prohibited by an insurance requirement under such Policy or Policies, or would invalidate the insurance coverage required hereunder to be maintained by Tenant on or with respect to any part of the Premises.

Tenant shall be responsible for any increase in insurance premiums or rates caused by or arising out of its use of the Premises.

B. <u>Landlord's Insurance</u>. Landlord shall take out and maintain in force throughout the Term, in a company or companies authorized to do business in New Hampshire, (i) all risk or equivalent special form coverage property insurance on the Building in an amount up to the full replacement value of the Building (exclusive of foundations), (ii) such boiler, machinery and equipment insurance as Landlord may from time to time deem necessary or desirable and (iii) commercial general liability insurance with limits not less than Two Million Dollars ($2,000,000) per occurrence with respect to the Building. Any insurance required to be maintained by Landlord hereunder may be maintained in the form of a blanket policy covering the Building as well as other properties owned by Landlord or affiliates of Landlord so long as the blanket policy does not reduce the limits nor diminish the coverage required herein. Upon request of Tenant, Landlord will provide evidence of such insurance to Tenant.

C. <u>Waiver of Subrogation</u>. Each party hereto does hereby remise, release and discharge the other party hereto and any officer, agent, employee or representative of such party, of and from any liability whatsoever hereafter arising from loss, damage or injury caused by fire or other casualty for which insurance (permitting waiver of liability and containing a waiver of subrogation) is carried by the injured party at the time of such loss, damage or injury to the extent of any recovery by the injured party under such insurance.

11. **WAIVER AND INDEMNITY.**

A. Waiver. Subject to the terms of Section 11(B) below, Tenant releases Landlord, its property manager and their respective agents, independent contractors and employees from, and waives all claims for, damage or injury to person or property and loss of business sustained by Tenant or its employees and resulting from the Project or any part thereof or any equipment therein becoming in disrepair, or resulting from any accident in or about the Project. This paragraph shall apply particularly, but not exclusively, to flooding, damage caused by Building equipment and apparatus, water, snow, frost, steam, excessive heat or cold, broken glass, sewage, gas, odors, excessive noise or vibration or the bursting or leaking of pipes, plumbing fixtures or sprinkler devices. Without limiting the generality of the foregoing, Tenant waives all claims and rights of recovery against Landlord, its property manager, independent contractors and their respective agents and employees for any loss or damage to any property of Tenant, which loss or damage is insured against, or required to be insured against, by Tenant pursuant to Section 10 above, whether or not such loss or damage is due to the fault or negligence of Landlord, its property manager, independent contractor or their respective agents or employees, and regardless of the amount of insurance proceeds collected or collectible under any insurance policies in effect.

B. Mutual Indemnity. Subject to the terms of Section 10(C), Tenant shall be solely responsible for, and agrees to indemnify, defend and hold harmless Landlord and its affiliates and its and their directors, officers, employees, property manager, agents, successors and assigns (the "Landlord Indemnified Parties") from and against, any and all damages, expenses, liabilities, demands, losses, claims, actions, judgments and costs of any kind including, without limitation, reasonable attorneys' fees (collectively, "Losses"), which any of the Landlord Indemnified Parties may incur to the extent relating to or arising out of the (i) the negligence or willful misconduct of the Tenant or Tenant's employees, agents, or contractors at the Project or (ii) an incident that occurs within the Premises and that results in personal injury or property damage, except for those incidents caused by the negligence or willful misconduct of Landlord or any of the other Landlord Indemnified Parties. The foregoing indemnity shall survive the termination of this Lease. Subject to the terms of Section 10(C), Landlord shall be solely responsible for, and agrees to indemnify, defend and hold harmless Tenant and its directors, officers, employees, agents, successors and assigns (the "Tenant Indemnified Parties") from and against, any and all Losses, which any of the Tenant Indemnified Parties may incur to the extent relating to or arising out of (i) the negligence or willful misconduct of Landlord or Landlord's agents or contractors within the Premises, or (ii) an incident that occurs at the Project other than within the Premises and that results in personal injury or property damage, except for those incidents caused by the negligence or willful misconduct of Tenant or any of the other Tenant Indemnified Parties. The foregoing indemnity shall survive the termination of this Lease.

12. **FIRE AND CASUALTY.**

A. Obligation to Repair or Rebuild. If the Premises or the Building shall be damaged or destroyed by fire or other casualty, Tenant shall promptly notify Landlord of any damage or destruction to the Premises which Tenant has knowledge or is aware of, and Landlord, subject to its mortgagee's consent and to the conditions set forth in this Section 12, shall repair, rebuild or replace such damage and restore the Premises and/or the Building, subject to Section 12.D and

Section 12.F below, to substantially the same condition in which they were immediately prior to such damage or destruction.

B. Commencement and Completion of Work. The work shall be commenced promptly and completed with due diligence, taking into account the time required by Landlord to effect a settlement with, and procure insurance proceeds from, the insurer, and for delays beyond Landlord's reasonable control.

C. Application of Proceeds. The net amount of any insurance proceeds (excluding proceeds received pursuant to any rental interruption coverage obtained by Landlord), recovered by reason of the damage or destruction of the Building in excess of the cost of adjusting the insurance claim and collecting the insurance proceeds (such excess amount being hereinafter called the "net insurance proceeds") shall be applied towards the reasonable cost of the work required to be performed by Landlord under this Section 12. If the net insurance proceeds are more than adequate to complete such work, the amount by which the net insurance proceeds exceed the cost of such work shall be retained by Landlord.

D. Tenant's Personal Property and Alterations. Landlord's obligation or election to restore the Premises under this Section 12 shall not include the repair, restoration or replacement of the furniture or any other personal property owned by or in the possession of Tenant, except for such furniture or other personal property that is located within the Premises as of the date of this Lease. In addition, Landlord shall not be under any obligation to repair, restore or replace any alterations or improvements to the Premises made by or on behalf of Tenant.

E. Abatement of Rent. Tenant will receive an abatement of Rent to the extent and during the time the Premises are rendered untenantable for the Permitted Use due to a fire or other casualty, such Rent to abate in such proportion as the part of the Premises thus destroyed or rendered untenantable bears to the total Premises from the date of such damage or destruction and until the earlier of (i) Landlord obtains a certificate of occupancy with respect to the completion of the work upon the Premises required to be performed by Landlord under this Section 12 or (ii) Tenant recommences use of such part of the Premises consistent with Tenant's typical use of such space prior to the fire or other casualty and, in cases in which the Premises are being restored by Landlord, to be conditioned upon Tenant not occupying such part of the Premises for its typical conduct of business (storage shall not constitute Tenant's typical conduct of business). If the Premises are so slightly damaged by such fire or other casualty as not to be rendered in any part untenantable for Tenant's business operations as reasonably determined by Tenant, Landlord shall complete the work upon the Premises required to be performed by Landlord under this Section 12 with reasonable promptness and the payment of Rent shall not be affected thereby. Tenant shall, at its own cost and expense, remove such of its furniture and furnishings and other belongings from the Premises as Landlord shall reasonably require in order to perform the work required to be performed by Landlord under this Section 12.

F. Landlord's Option Not to Restore. Notwithstanding any of the foregoing provisions of this Section 12 to the contrary, if there is substantial damage to the Building due to a fire or other casualty, or if, in the judgment of Landlord's architect, damage to the Premises due to a fire or other casualty is such that the work upon the Premises required to be performed by Landlord under this Section 12 with respect to such fire or other casualty cannot be completed within one hundred eighty (180) days after such fire or other casualty, then Landlord shall have the option not to perform the work upon the Premises required to be performed by Landlord under this Section 12 with respect to such fire or other casualty, and may elect to terminate this Lease by sending a written notice of such termination to Tenant, the notice to specify a termination date not less than thirty (30) days after its transmission. Landlord shall notify Tenant in writing within sixty (60) days after the date of such fire or other casualty of such architect's estimate of the period of time required to perform the work upon the Premises required to be performed by Landlord with respect to such fire or other casualty.

G. Tenant's Right to Terminate. Notwithstanding anything herein to the contrary, if the Premises are damaged by a fire or other casualty and if Landlord fails to restore the Premises, subject to the terms of Section 12D above, within one hundred eighty (180) days after such fire or other casualty, then Tenant may terminate this Lease by written notice to Landlord at any time after the end of such one hundred eighty (180) day period but prior to the date that Landlord has completed such restoration work.

13. **CONDEMNATION.** If the Premises or the Building is rendered untenantable for the Permitted Use by reason of a condemnation (or by a deed given in lieu thereof), then either party may terminate this Lease by giving written notice of termination to the other party within thirty (30) days after such condemnation, in which event this Lease shall terminate effective as of the date of such condemnation. If this Lease so terminates, Rent shall be paid through and apportioned as of the date of such condemnation. If such condemnation does not render the Premises or the Building untenantable, this Lease shall continue in effect and Landlord shall promptly restore the portion not condemned to the extent reasonably possible to the condition existing prior to the condemnation. All damages or awards awarded for such taking under the power of eminent domain, whether for the whole or a part of the Premises, will belong to and be the property of Landlord will; provided, however, that Tenant will be entitled to pursue and continue any award made for depreciation to, the cost of removal of Tenant's equipment and movable furniture and trade fixtures, if any, and any other claims available to Tenant at law or in equity.

14. **ASSIGNMENT AND SUBLETTING**

A. Landlord's Consent. Tenant shall not, without the prior written consent, such consent to be given in the reasonable discretion of Landlord: (i) assign, convey, mortgage or otherwise transfer this Lease or any interest hereunder, or sublease the Premises, or any part thereof, whether voluntarily or by operation of law; or (ii) permit the use of the Premises or any part thereof by any person other than Tenant and its employees. Any such transfer, sublease or use described in the preceding sentence (herein referred to as a "Transfer", which term shall include any reassignment of this Lease after any initial assignment of this Lease by the Tenant named herein, i.e. Liberty Utilities, or any subsequent reassignment and any assignment of any sublease with respect to all or any portion of the Premises and any sub-subleasing of any portion of the Premises previously subleased) occurring without the prior written consent of Landlord shall be void and of no effect. Landlord's consent to any Transfer shall not constitute a waiver of Landlord's right to withhold its consent to any future Transfer. Landlord's consent to any Transfer or acceptance of rent from any party other than Tenant shall not release Tenant from any covenant or obligation under this Lease. Landlord may require as a condition to its consent to any assignment of this Lease that the assignee execute an instrument in which such assignee assumes the obligations of Tenant hereunder, provided such instrument is reasonably acceptable to Tenant and such assignee.

B. Standards for Consent. If Tenant desires the consent of Landlord to a Transfer, Tenant shall submit to Landlord, at least thirty (30) days prior to the proposed effective date of the Transfer, a written notice which includes such information as Landlord may reasonably require about the proposed Transfer and the transferee. If Landlord does not terminate this Lease, in whole or in part, pursuant to Section 14C, Landlord shall not unreasonably withhold its consent to any assignment or sublease. Landlord shall not be deemed to have unreasonably withheld its consent if, in the judgment of Landlord: (i) the transferee is of a character or engaged in a business which is not in keeping with the standards or criteria used by Landlord in leasing the Building; (ii) the financial condition of the transferee is such that it may not be able to perform its obligations in connection with this Lease; (iii) the purpose for which the transferee intends to use the Premises or portion thereof is in violation of the terms of this Lease or would violate the exclusivity rights of any other tenant in the Building; (iv) the transferee is a tenant of the Building; or (v) any other bases which Landlord reasonably deems appropriate, including an assignment or sublease at less than the fair market rate for that would otherwise be charged for the premises. If Landlord wrongfully withholds its consent to any Transfer, Tenant's sole and exclusive remedy therefor, shall be to seek specific performance of Landlord's obligation to consent to such Transfer. If Landlord consents to any Transfer, Tenant shall pay to Landlord fifty percent (50%) of all rent and other consideration received by Tenant in excess of the Rent paid by Tenant hereunder for the portion of the Premises so transferred after deducting all costs Tenant incurs in effectuating such Transfer (including, without limitation, brokerage commissions, costs of any Alterations that Tenant may make to the Premises in connection with such Transfer, legal fees, and tenant improvement allowances that Tenant may provide to such transferee). Such rent shall be paid as and when received by Tenant.

C. Recapture. Landlord shall have the right to terminate this Lease as to that portion of the Premises covered by a Transfer. Landlord may exercise such right to terminate by giving notice to Tenant at any time within thirty (30) days after the date on which Tenant has furnished to Landlord all of the items required under Section 14B above. If Landlord exercises such right to terminate, Landlord shall be entitled to recover possession of, and Tenant shall surrender such portion of, the Premises (with appropriate demising partitions erected at the expense of Tenant) on the later of (i) the effective date of the proposed Transfer, or (ii) sixty (60) days after the date of Landlord's notice of termination. In the event Landlord exercises such right to terminate, Landlord shall have the right to enter into a lease with the proposed transferee without incurring any liability to Tenant on account thereof.

D. No Release. Except in the event of a termination under Section 14(C), in no event shall any Transfer release or relieve Tenant from its obligations to fully observe or perform all of the terms, covenants and conditions of this Lease on its part to be observed or performed. It is agreed that the liabilities and obligations of Tenant hereunder are enforceable either before, simultaneously with or after proceeding against any assignee, sublessee or other transferee of Tenant.

E. Permitted Transfers. Notwithstanding anything in this Section 14 to the contrary, Tenant may Transfer all or part of its interest in this Lease or all or part of the Premises (a

"Permitted Transfer") to the following types of entities (a "Permitted Transferee") without the written consent of Landlord:

(1) an Affiliate of Tenant;

(2) any corporation, limited partnership, limited liability partnership, limited liability company or other business entity in which or with which Tenant, or its corporate successors or assigns, is merged or consolidated, in accordance with applicable statutory provisions governing merger and consolidation of business entities, so long as Tenant's obligations hereunder are assumed by the entity surviving such merger or created by such consolidation; or

(3) any corporation, limited partnership, limited liability partnership, limited liability company or other business entity acquiring all or substantially all of Tenant's assets, stock, or membership interests.

Landlord acknowledges and agrees that the Premises may be occupied by one or more Affiliates pursuant to occupancy agreement(s) or license agreement(s) entered into by Tenant and such Affiliate, and Landlord agrees that the execution of such agreement(s) will not be deemed to be an assignment of this Lease or sublease of the Premises under the terms of the Lease. Tenant shall promptly notify Landlord of any such Permitted Transfer. Tenant shall remain liable for the performance of all of the obligations of Tenant hereunder, or if Tenant no longer exists because of a merger, consolidation, or acquisition, the surviving or acquiring entity shall expressly assume in writing the obligations of Tenant hereunder. Additionally, the Permitted Transferee shall comply with all of the terms and conditions of this Lease, including the Permitted Use, and the use of the Premises by the Permitted Transferee may not violate any other exclusivity rights that Landlord has granted to any other tenant of the Building or Project. Nothing herein, however, shall prohibit Tenant or such Permitted Transferee from using the Premises for the Permitted Use. No later than ten (10) business days after the effective date of any Permitted Transfer, Tenant agrees to furnish Landlord with (A) documentation establishing Tenant's satisfaction of the requirements set forth above applicable to any such Transfer, and (B) evidence of insurance as required under this Lease with respect to the Permitted Transferee. The occurrence of a Permitted Transfer shall not waive Landlord's rights as to any subsequent Transfers. As used herein, the term "Affiliate" shall mean any person or entity which, directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with the party in question. Any subsequent Transfer by a Permitted Transferee shall be subject to the terms of this Section 14.

15. **SURRENDER.** Upon the expiration or earlier termination of the Term or Tenant's right to possession of the Premises, Tenant shall return the Premises to Landlord broom clean and in the condition required to be maintained by Tenant hereunder, reasonable wear and tear, damage by casualty, and repairs for which the Landlord is responsible excepted. If Landlord requires Tenant to remove any Alterations pursuant to Section 9, then such removal shall be done in a good and workmanlike manner; and upon such removal Tenant shall repair any damage caused thereby to the Premises. If Tenant does not remove such Alterations after request to do so by Landlord and provided Tenant was notified of such requirement for removal at the time Landlord consented to the Alteration, Landlord may remove the same; and Tenant shall pay the cost of such removal and repair to Landlord within thirty (30) days after Tenant's receipt of an invoice

and reasonable supporting documentation therefor. Tenant shall also remove its furniture, equipment, trade fixtures and all other items of personal property from the Premises prior to the time Tenant surrenders the Premises to Landlord. If Tenant does not remove such items, Tenant shall be conclusively presumed to have conveyed the same to Landlord without further payment or credit by Landlord to Tenant; or at Landlord's sole option such items shall be deemed abandoned, in which event Landlord may cause such items to be removed and disposed of at Tenant's expense, without notice to Tenant and without obligation to compensate Tenant.

16. **DEFAULTS AND REMEDIES.**

A. Default. The occurrence of any of the following shall constitute a default (a "Default") by Tenant under this Lease:

(i) Tenant fails to pay any Rent when due and such failure to pay is not cured within five (5) days after Tenant's receipt of notice of such failure from Landlord; however, a Default shall occur without any obligation of Landlord to give any notice if Landlord has given Tenant written notice under this Section 16.A(i) on one (1) prior occasion during the twelve (12) month interval preceding such failure to pay by Tenant;

(ii) Tenant fails to perform or observe any other covenants or obligations of Tenant set forth in this Lease and such failure to perform is not cured within thirty (30) days after Tenant's receipt of notice of such failure from Landlord, provided that if such failure reasonably requires more than thirty (30) days to cure, Tenant shall have such reasonable time to cure as long as Tenant commences curing the failure within such initial thirty (30) day period and thereafter diligently pursues such cure to completion;

(iii) the leasehold interest of Tenant is levied upon or attached under process of law;

(iv) Tenant or any guarantor of this Lease dies or dissolves;

(v) Tenant abandons or vacates the Premises and ceases to pay Rent for more than forty-five (45) days; or

(vi) any voluntary or involuntary proceedings are filed by or against Tenant or any guarantor of this Lease under any bankruptcy, insolvency or similar laws and, in the case of any involuntary proceedings, are not dismissed within thirty (30) days after filing.

B. Right of Re-Entry. Upon the occurrence of a Default, Landlord may elect to terminate this Lease, or, without terminating this Lease, terminate Tenant's right to possession of the Premises. Upon any such termination, Tenant shall immediately surrender and vacate the Premises and deliver possession thereof to Landlord. Tenant grants to Landlord the right to enter and repossess the Premises and to expel Tenant and any others who may be occupying the Premises and to remove any and all property therefrom pursuant to the applicable legal process for such repossession, expulsion, and removal, without being deemed in any manner guilty of trespass and without relinquishing Landlord's rights to Rent or any other right given to Landlord hereunder or by operation of law.

C. Reletting. If Landlord terminates Tenant's right to possession of the Premises without terminating this Lease, Landlord may relet the Premises or any part thereof. In such case, Landlord shall use reasonable efforts to relet the Premises on such terms as Landlord shall reasonably deem appropriate; provided, however, Landlord may first lease Landlord's other available space and shall not be required to accept any tenant offered by Tenant or to observe any instructions given by Tenant about such reletting. Tenant shall reimburse Landlord for the costs and expenses of reletting the Premises including, but not limited to, all brokerage, advertising, legal, alteration and other expenses incurred to secure a new tenant for the Premises as such are reasonably allocated to any remaining Term of this Lease. In addition, if the consideration collected by Landlord upon any such reletting, after payment of the expenses of reletting the Premises which have not been reimbursed by Tenant, is insufficient to pay monthly the full amount of the Rent, Tenant shall pay to Landlord the amount of each monthly deficiency as it becomes due. If such consideration is greater than the amount necessary to pay the full amount of the Rent, the full amount of such excess shall be retained by Landlord and shall in no event be payable to Tenant.

D. Termination of Lease. If Landlord terminates this Lease pursuant to the terms and provisions of this Section 16, Landlord may recover from Tenant and Tenant shall pay to Landlord, on demand, the Rent and other charges payable by Tenant to Landlord through the date of termination, and, in addition, shall pay to Landlord as damages, at the election of Landlord, either: (x) an accelerated lump sum amount equal to the present value (discounted at one percent (1%) over the then current discount rate of the Federal Reserve Bank of Boston, Massachusetts) of the amount by which Landlord's estimate of the aggregate amount of Rent owing from the date of such termination through the Expiration Date plus Landlord's estimate of the aggregate expenses of reletting the Premises exceeds Landlord's estimate of the fair rental value of the Premises for the same period (after deducting from such fair rental value the time needed to relet the Premises and the amount of concessions which would normally be given to a new tenant); or (y) amounts equal to the Rent which would have been payable by Tenant had this Lease not been so terminated, payable upon the due dates therefor specified herein following such termination and until the Expiration Date; provided, however, if Landlord shall re-let the Premises during such period, that Landlord shall credit Tenant with the net rents received by Landlord from such re-letting, such net rents to be determined by first deducting from the gross rents as and when received by Landlord from such re-letting the expenses incurred or paid by Landlord in terminating this Lease, as well as the expenses of re-letting as proportionately applied to the balance of the term of this Lease at the time of termination, including altering and preparing the Premises for new tenants, brokerage commissions, and all other similar and dissimilar expenses properly chargeable against the Premises and the rental therefrom, it being understood that any such re-letting may be for a period equal to or shorter or longer than the remaining Term of this Lease; and provided, further, that (i) in no event shall Tenant be entitled to receive any excess of such net rents over the sums payable by Tenant to Landlord hereunder and (ii) in no event shall Tenant be entitled in any suit for the collection of damages pursuant to this subparagraph (y) to a credit in respect of any net rents from a re-letting except to the extent that such net rents are actually received by Landlord prior to the commencement of such suit. If the Premises or any part thereof shall be re-let in combination with other space, a proper apportionment on a square foot area basis shall be made of the rent received from re-letting and other expenses of such re-letting.

E. Other Remedies. Landlord may but shall not be obligated to perform any obligation of Tenant under this Lease; and, if Landlord so elects, all costs and expenses paid by Landlord in performing such obligation, together with interest at the Default Rate, shall be reimbursed by Tenant to Landlord on demand. Any and all remedies set forth in this Lease: (i) shall be in addition to any and all other remedies Landlord may have at law or in equity, (ii) shall be cumulative, and (iii) may be pursued successively or concurrently as Landlord may elect. The exercise of any remedy by Landlord shall not be deemed an election of remedies or preclude Landlord from exercising any other remedies in the future.

F. Bankruptcy. If Tenant becomes bankrupt, the bankruptcy trustee shall not have the right to assume or assign this Lease unless the trustee complies with all requirements of the United States Bankruptcy Code; and Landlord expressly reserves all of its rights, claims, and remedies thereunder.

G. Waiver of Trial by Jury. Landlord and Tenant waive trial by jury in the event of any action, proceeding or counterclaim brought by either Landlord or Tenant against the other in connection with this Lease.

H. Landlord's Right to Perform Tenant's Obligations; Emergency. In the event of imminent danger to person or property related to the Premises, Landlord shall have the right but not the obligation to immediately perform any obligation of Tenant under this Lease to address such imminent danger upon written notice thereof to Tenant; and, if Landlord so elects all costs and expenses paid by Landlord in performing such obligation shall be reimbursed by Tenant to Landlord within thirty (30) days after receipt of an invoice and reasonable supporting documentation therefor.

I. Landlord Default. A "Landlord Default" shall occur if Landlord fails to perform any obligations imposed upon Landlord by this Lease, and such failure continues for more than thirty (30) days after written notice thereof has been delivered by Tenant to Landlord, provided that Landlord will have such period of time reasonably necessary to cure such failure if it is of such a nature that it cannot reasonably be cured within thirty (30) days, so long as Landlord commences curing within said thirty (30) day period and thereafter diligently pursues such cure to completion. In the event of a Landlord Default, Tenant may, without limiting any other right that Tenant may have either in equity or in law, either terminate this Lease if such Landlord Default materially interferes with Tenant's operation on the Premises, or cure such Landlord Default and charge the cost of such cure to Landlord. If Landlord does not reimburse Tenant for the costs incurred to cure the Landlord Default within thirty (30) days after receipt of an invoice for such charges, Tenant may offset such amounts against any Rent due under this Lease. Nothing herein shall be deemed to limit Tenant's right to cure a default of Landlord in the event of an emergency or in the event that Tenant's operations or Tenant's property are materially jeopardized.

17. **HOLDING OVER.** If Tenant retains possession of the Premises after the expiration or termination of the Term or Tenant's right to possession of the Premises, Tenant shall be a month-to-month tenant on the same terms and conditions as set forth herein, except that the monthly

Rent shall be 150% of the monthly Base Rent and Adjustment Rent in effect immediately preceding such holding over. If Tenant holds over for more than thirty (30) days and Landlord has delivered written notice to Tenant that Landlord has entered into an agreement with another tenant to occupy the Premises after Tenant vacates, Tenant shall also pay, indemnify and defend Landlord from and against all claims and damages, consequential as well as direct, sustained by reason of Tenant's holding over.

18. **SECURITY DEPOSIT.** None.

19. **PARKING.** Tenant shall be permitted to use at no cost to Tenant the parking spaces in the Parking Facility (see Exhibit C) as well as the parking spaces shown as the Easement Area in Exhibit C. Such parking spaces shall be available for Tenant's use on an unassigned, non-reserved basis, provided that Tenant shall always have the right to use at least 3.5 spaces per 1,000 square feet of space within the Premises as to the Parking Facility and at least 2.4 spaces per 1,000 square feet of space within the Premises as to the Easement Area. Landlord may, pursuant to Section 6 above, establish reasonable rules and regulations regarding Tenant's use of such parking spaces, provided that in the event of any conflict between the terms of this Lease and the terms of such rules and regulations, the terms of this Lease shall prevail. Tenant's right to use such parking spaces shall be subject to the terms and provisions of this Lease.

20. **ESTOPPEL CERTIFICATES.** Tenant agrees that, from time to time upon not less than ten (10) business days' prior request by Landlord, Tenant shall execute and deliver to Landlord a written certificate certifying: (i) that this Lease is unmodified and in full force and effect (or if there have been modifications, a description of such modifications and that this Lease as modified is in full force and effect); (ii) the dates to which Rent has been paid; (iii) that Tenant is in possession of the Premises, if that is the case; (iv) that to the knowledge of Tenant, Landlord is not in default under this Lease, or, if Tenant believes Landlord is in default, the nature thereof in detail; (v) that Tenant has no off-sets or defenses to the performance of its obligations under this Lease (or if Tenant believes there are any off-sets or defenses, a full and complete explanation thereof); and (vi) such additional matters directly related to the terms of this Lease as may be requested by Landlord, it being agreed that such certificate may be relied upon by any prospective purchaser, mortgagee or other person having or acquiring an interest in the Building.

21. **SUBORDINATION, NON-DISTURBANCE & ATTORNMENT.** The lien of this Lease is and shall be expressly subject and subordinate at all times to (a) any present or future ground, underlying or operating lease of the Building, and all amendments, renewals and modifications to any such lease, and (b) the lien of any present or future mortgage or deed of trust encumbering fee title to the Building and/or the leasehold estate under any such lease, provided the ground lessor, mortgagee or trustee named in said leases, mortgages or trust deeds will agree to recognize this Lease in the event of termination of such leases, foreclosure or a deed in lieu of foreclosure if Tenant is not in Default. If any such mortgage or deed of trust be foreclosed, or if any such lease be terminated, upon request of the mortgagee, beneficiary or lessor, as the case may be, Tenant will attorn to the purchaser at the foreclosure sale or to the lessor under such lease, as the case may be. Notwithstanding the foregoing, Tenant's subordination of the lien of this Lease will not be effective unless and until it has received a subordination, non-disturbance, and attornment agreement reasonably acceptable to Tenant, recognizing all of Tenant's rights

under this Lease, and signed by the lessor of any ground, underlying, or operating lease or holder of any mortgages or deeds of trust upon the Building (an "SNDA Agreement"). Tenant shall promptly execute such SNDA Agreement after Tenant's receipt thereof. Notwithstanding the foregoing to the contrary, any such mortgagee, beneficiary or lessor may elect to give the rights and interests of Tenant under this Lease (excluding rights in and to insurance proceeds and condemnation awards) priority over the lien of its mortgage or deed of trust or the estate of its lease, as the case may be. In the event of such election and upon the mortgagee, beneficiary or lessor notifying Tenant of such election, the rights and interests of Tenant shall be deemed superior to and to have priority over the lien of said mortgage or deed of trust or the estate of such lease, as the case may be, whether this Lease is dated prior to or subsequent to the date of such mortgage, deed of trust or lease. In such event, Tenant shall execute and deliver whatever instruments may be required by such mortgagee, beneficiary or lessor to confirm such superiority on a form reasonably acceptable to Tenant.

Landlord shall obtain a signed SNDA Agreement from the lessor under any present ground, underlying or operating lease of the Building and from the holder of any present mortgage encumbering fee title to the Building and from the beneficiary under any present or future deed of trust encumbering fee title to the Building within sixty (60) days after the Commencement Date. If Landlord fails to obtain and deliver to Tenant such signed Non-Disturbance Agreement(s) within such sixty (60) days, Base Rent shall be abated until Tenant receives an SNDA Agreement from the lessor under any present ground, underlying or operating lease of the Building and from the holder of any present mortgage encumbering fee title to the Building and from the beneficiary under any present or future deed of trust encumbering fee title to the Building.

22. **QUIET ENJOYMENT.** As long as no Default exists, Tenant shall peacefully and quietly have and enjoy the Premises for the Term, free from interference by Landlord, subject, however, to the provisions of this Lease. The loss or reduction of Tenant's light, air or view will not be deemed a disturbance of Tenant's occupancy of the Premises nor will it affect Tenant's obligations under this Lease or create any liability of Landlord to Tenant.

23. **BROKERS.** Tenant represents to Landlord that Tenant has dealt only with the brokers set forth in Item 7 of the Schedule (the "Brokers") in connection with this Lease and that, insofar as Tenant knows, no other broker(s) negotiated this Lease or is entitled to any commission in connection herewith. Tenant agrees to indemnify, defend and hold Landlord, its property manager and their respective employees harmless from and against any claims for a fee or commission made by any broker(s), other than the Brokers, claiming to have acted by or on behalf of Tenant in connection with this Lease. Landlord represents to Tenant that Landlord has dealt only with the brokers set forth in Item 7 of the Schedule (the "Brokers") in connection with this Lease and that, insofar as Landlord knows, no other broker(s) negotiated this Lease or is entitled to any commission in connection herewith. Landlord agrees to indemnify, defend and hold Tenant and its employees harmless from and against any claims for a fee or commission made by any broker(s), other than the Brokers, claiming to have acted by or on behalf of Landlord in connection with this Lease. Landlord agrees to pay the Brokers commissions in accordance with separate agreements between Landlord and the Brokers.

24. **NOTICES.** All notices and demands to be given by one (1) party to the other party under this Lease shall be given in writing, mailed or delivered to Landlord or Tenant, as the case may be, at the address of each party set forth in the Schedule or at such other address as either party may hereafter designate. Notices shall be delivered by hand or by United States certified or registered mail, postage prepaid, return receipt requested, or by a nationally recognized overnight air courier service. Notices shall be considered to have been given upon the earlier to occur of actual receipt or refusal to accept delivery thereof.

25. **MISCELLANEOUS.**

A. Successors and Assigns. Subject to Section 14 of this Lease, each provision of this Lease shall extend to, bind and inure to the benefit of Landlord and Tenant and their respective legal representatives, successors and assigns; and all references herein to Landlord and Tenant shall be deemed to include all such parties.

B. Entire Agreement. This Lease, and the riders and exhibits, if any, attached hereto which are hereby made a part of this Lease, represent the complete agreement between Landlord and Tenant; and Landlord has made no representations or warranties except as expressly set forth in this Lease. No modification or amendment of or waiver under this Lease shall be binding upon Landlord or Tenant unless in writing signed by Landlord and Tenant. The normal rule of construction that any ambiguities be resolved against the drafting party shall not apply to the interpretation of this Lease or any exhibits or amendments hereto.

C. Time of Essence. Time is of the essence of this Lease and each and all of its provisions.

D. Execution and Delivery. Submission of this instrument for examination or signature by Tenant does not constitute a reservation of space or an option for lease, and it is not effective until execution and delivery by both Landlord and Tenant. Execution and delivery of this Lease by Tenant to Landlord shall constitute an irrevocable offer by Tenant to lease the Premises on the terms and conditions set forth herein, which offer may not be revoked for fifteen (15) days after such delivery.

E. Severability. The invalidity or unenforceability of any provision of this Lease shall not affect or impair any other provisions.

F. Governing Law. This Lease shall be governed by and construed in accordance with the laws of the State in which the Premises are located.

G. Attorneys' Fees. In the event of a Default, Tenant shall pay to Landlord all costs and expenses, including reasonable attorneys fees, incurred by Landlord in enforcing this Lease.

H. Joint and Several Liability. If Tenant is comprised of more than one party, each such party shall be jointly and severally liable for Tenant's obligations under this Lease.

I. Force Majeure. Excepting only the payment of money, in the event that either party hereto will be delayed or hindered in or prevented from the performance of any act required hereunder by reason of fire, flood, hurricane, explosion, war (declared or undeclared), invasion, insurrection, riot, mob violence, sabotage, as well as (i) strikes (ii) lockouts, (iii) action of labor unions which are not avoidable by, or a result of, the actions or decisions of, the delayed party, and reasonable delays related to condemnation, public requisition laws, orders of government or civil or defense authorities in performing work or doing acts required under the terms of this Lease, then performance of such act will be excused for the period of the delay and the period for the performance of any such act will be extended for a period equivalent to the period of such delay. The party entitled to such extension hereunder will give written notice as soon as possible to the other party hereto of its claim of right to such extension and the reason(s) therefor.

J. Captions. The headings and titles in this Lease are for convenience only and shall have no effect upon the construction or interpretation of this Lease.

K. No Waiver. No receipt of money by Landlord from Tenant after termination of this Lease or after the service of any notice or after the commencing of any suit or after final judgment for possession of the Premises shall renew, reinstate, continue or extend the Term or affect any such notice or suit. No waiver of any default of Tenant shall be implied from any omission by Landlord to take any action on account of such default if such default persists or be repeated, and no express waiver shall affect any default other than the default specified in the express waiver and then only for the time and to the extent therein stated.

L. No Recording. Tenant shall not record this Lease or a notice of this Lease in any official records.

M. Limitation of Liability. Any liability of Landlord under this Lease shall be limited solely to its equity in the Building, and in no event shall any personal liability be asserted against Landlord in connection with this Lease nor shall any recourse be had to any other property or assets of Landlord.

N. Intentionally Deleted.

O. Telecommunications. Tenant and its telecommunications companies, including but not limited to local exchange telecommunications companies and alternative access vendor services companies, shall have no right of access to and within the Building for the installation and operation of telecommunications systems, including but not limited to voice, video, data, and any other telecommunications services provided over wire, fiber optic, microwave, wireless, and any other transmission systems, for part or all of Tenant's telecommunications within the Building and from the Building to any other location without Landlord's prior written consent, which shall not be unreasonably withheld, delayed, or conditioned.

P. Load Bearing Capacity. Tenant shall not place a load upon any floor of the Premises which exceeds the load per square foot which such floor was designed to carry and which is allowed by law. Landlord reserves the right to prescribe in a reasonable manner the weight and position of all safes and heavy installations which Tenant wishes to place in the Premises so as to properly distribute the weight thereof.

Q. General Provision. If any provision of this lease is later considered to be vague or if there is any question, dispute or controversy concerning the interpretation or application of any provision of this lease, this lease, either in whole or in part, will not be construed against the "drafter" and in favor of the other party hereto. Accordingly, the language used in this lease shall be deemed to be the language mutually chosen by the parties to express their mutual intent, and no rule of strict construction shall be applied.

R. Waiver Of Landlord Lien. Landlord hereby expressly waives and releases any and all contractual liens and security interests or constitutional and/or statutory liens and security interests arising by operation of law to which Landlord might now or hereafter be entitled on all the property of Tenant or any Affiliate of Tenant which is now or hereafter placed in or upon the Premises (except for judgment liens that may arise in favor of Landlord).

26. **TENANT IMPROVEMENTS.** None – Subject to the terms of this Lease, Tenant agrees to lease the Premises "as is" in the configuration shown on Exhibit A – Floor Plan. Tenant, at its sole expense, will do all tenant improvements, subject to the terms of Section 9 of this Lease, including the prior review and approval of the Landlord and Town of Salem as applicable. Tenant has the right to use their own licensed & insured contractors for improvements to the Premises and Signage.

27. **LANDLORD IMPROVEMENTS.** Landlord shall deliver the Premises with all electrical, lighting, plumbing and HVAC in good working order. Also, any/all damaged acoustical ceiling tiles shall be replaced prior to delivery. Notwithstanding anything contained herein to the contrary, if Landlord fails to deliver the Premises to Tenant on or before August 1, 2019, Tenant's Rent credit period (currently August 1, 2019 through September 30, 2019) shall be extended on a day for day basis for each day of delay in Landlord's delivery of the Premises. If such delay extends for ninety (90) days, Tenant may, at any time thereafter, elect to terminate this Lease by providing at least ten (10) days' advance written notice to Landlord, and, in such event, Tenant will have no further obligations hereunder.

28. **CREDIT (BASE RENT AND ADJUSTMENT RENT).** Tenant shall receive a credit against the Base Rent and Adjustment Rent (sometimes referred to as the Common Area Expenses) otherwise due for the period of 8/1/19 – 9/30/19.

29. **OPTION TO EXTEND.** On the condition that Tenant is not in default of its covenants and obligations under this Lease (beyond applicable notice and cure periods) both at the time of option exercise and as of the commencement of the hereinafter described additional term, Tenant shall have the option ("Tenant's Extension Option") to extend the Term for an additional term of five (5) years (herein referred to as the "Additional Term"), said Additional Term to commence immediately after the expiration of the initial Term. If Tenant desires to extend the Term as aforesaid, it shall give notice thereof to Landlord no later than one hundred twenty (120) days prior to the end of the initial Term. If Tenant timely gives such notice (time being of the essence), then the Term shall be deemed extended upon all of the same terms and conditions of this Lease, except that the Annual Base Rent during said Additional Term shall be increased each August 1st (including the first year of the Additional Term) by three percent (3%).

30. **SIGNS.** Except as provided in the following paragraph and except for signs which are located wholly within the interior of the Premises and which are not visible from the exterior of

the Premises, no sign shall be placed, erected, maintained or painted by Tenant at any place upon the Premises or the Building.

Notwithstanding anything in the preceding paragraph to the contrary, Tenant, at its sole cost and expense, may install one (1) sign identifying Tenant's business on the pylon sign along Main Street (large upper panel), one (1) sign on the building fascia above the entrance and one (1) sign near the entry door to the unit. The specific location, size and design of such signs shall be subject to the prior written approval of Landlord, which shall not be unreasonably withheld, delayed, or conditioned. Tenant shall be responsible for obtaining all necessary governmental permits and approvals for the installation of such signs and may not commence such installations unless and until Tenant has provided to Landlord a copy of all such permits and approvals. Such signs shall be installed in accordance with the approved plans and specifications, in a good and workmanlike manner, in accordance with all governmental laws, rules and regulations, and in a manner so as not to unreasonably interfere with the use of the Building by others entitled thereto. Throughout the Term, Tenant shall, at Tenant's sole cost and expense, maintain such signs in a good, clean and safe condition. Tenant shall, at Tenant's sole cost and expense, remove such signs prior to the expiration or earlier termination of the Term. Tenant shall, at Tenant's sole cost and expense, repair all damage caused by the removal of such signs. If such signs are not removed as required herein, such signs shall, at Landlord's option, be deemed to have been abandoned by Tenant and may be appropriated, sold, stored, destroyed or otherwise disposed of by Landlord without notice to Tenant. The provisions of this Section 30 shall survive the end of the Term.

TENANT'S REVIEW OF LEASE AGREEMENT.

Tenant acknowledges the legal consequences of this Lease Agreement in negotiating with the Landlord and acknowledges that the Landlord has recommended that the Tenant review this Agreement and related Exhibits with Tenant's legal representative or counsel prior to the execution of this Agreement. Tenant further acknowledges and represents that the individual executing this Lease Agreement on behalf of Tenant is duly authorized to enter into this Agreement and to bind the Tenant to the terms herein.

IN WITNESS WHEREOF, Landlord and Tenant have executed this Lease as a sealed instrument as of the day and year first above written.

LANDLORD:

E-POINT, LLC,
a New Hampshire Limited Liability Company

By: ______________________

Name: Peter R. Milnes, Trustee
The Peter R. Milnes Rev. Trust of 1994, Member

TENANT:

LIBERTY ENERGY UTILITIES (NEW HAMPSHIRE) CORP.,
a Delaware corporation

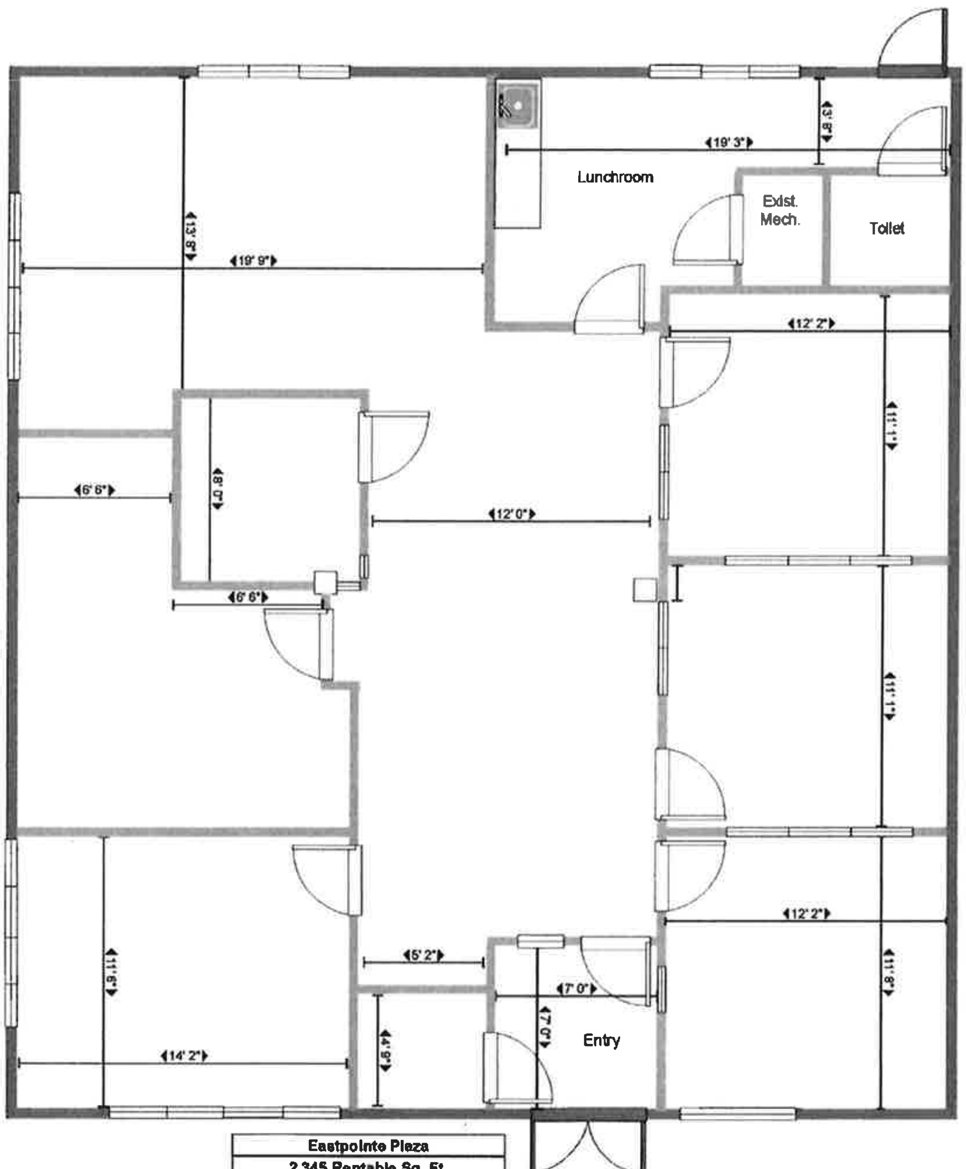
By: ______________________

Name: Susan Fleck

Title: President

EXHIBIT A

FLOOR PLAN SHOWING THE PREMISES



Eastpointe Plaza
2,345 Rentable Sq. Ft.
1st Floor
Approximate dimensions. Not to scale.

EXHIBIT B

RULES AND REGULATIONS

1. Tenant shall not make any room-to-room canvas to solicit business from other tenants in the Building and shall not exhibit, sell or offer to sell, use, rent or exchange any item or services in or from the Premises unless ordinarily included within Tenant's use of the Premises as specified in the Lease.

2. Tenant shall not make any use of the Premises which may be dangerous to person or property or which shall increase the cost of insurance or require additional insurance coverage.

3. Tenant shall not paint, display, inscribe or affix any sign, picture, advertisement, notice, lettering or direction or install any lights on any part of the outside or inside of the Building, other than the Premises, and then not on any part of the inside of the Premises which can be seen from outside the Premises, except as approved by Landlord in writing.

4. Tenant shall not use the name of the Building in advertising or other publicity, except as the address of its business, and shall not use pictures of the Building in advertising or publicity.

5. Tenant shall not obstruct or place objects on or in sidewalks, entrances, passages, courts, corridors, vestibules, halls, elevators and stairways in and about the Building. Tenant shall not place objects against glass partitions or doors or windows or adjacent to any open common space which would be unsightly from the Building corridors or from the exterior of the Building.

6. Bicycles shall not be permitted in the Building other than in locations designated by Landlord.

7. Tenant shall not allow any animals, other than registered service animals approved by the Landlord, in the Premises or the Building that are disruptive to other tenants and not under the control of the owner (on a leash outside the Premises) at all times.

8. Tenant shall not disturb other tenants or make excessive noises, cause disturbances, create excessive vibrations, odors or noxious fumes or use or operate any electrical or electronic devices or other devices that emit excessive sound waves or are dangerous to other tenants of the Building or that would interfere with the operation of any device or equipment or radio or television broadcasting or reception from or within the Building or elsewhere, and shall not place or install any projections, antennae, aerials or similar devices outside of the Building or the Premises.

9. Tenant shall not waste electricity or water and shall cooperate fully with Landlord to assure the most effective operation of the Building's heating and air conditioning, and shall refrain from attempting to adjust any controls except for the thermostats within the Premises. Tenant shall keep all doors to the Premises closed.

10. Unless Tenant installs new doors to the Premises, Landlord shall furnish two (2) sets of keys for all doors to the Premises at the commencement of the Term. Tenant shall furnish Landlord with duplicate keys for any new or additional locks on doors installed by Tenant. When the Lease is terminated, Tenant shall deliver all keys to Landlord and will provide to Landlord the means of opening any safes, cabinets or vaults left in the Premises.

11. Except as otherwise provided in the Lease, Tenant shall not install any signal, communication, alarm or other utility or service system or equipment without the prior written consent of Landlord.

12. Tenant shall not use any draperies or other window coverings instead of or in addition to the Building standard window coverings designated and approved by Landlord for exclusive use throughout the Building.

13. Landlord may require that all persons who enter or leave the Building identify themselves to watchmen, by registration or otherwise. Landlord, however, shall have no responsibility or liability for any theft, robbery or other crime in the Building. Tenant shall assume full responsibility for protecting the Premises, including keeping all doors to the Premises locked after the close of business.

14. Tenant shall not overload floors; and Tenant shall obtain Landlord's prior written approval as to size, maximum weight, routing and location of business machines, safes, and heavy objects. Tenant shall not install or operate machinery or any mechanical devices of a nature not directly related to Tenant's ordinary use of the Premises.

15. In no event shall Tenant bring into the Building inflammables such as gasoline, kerosene, naphtha and benzene, or explosives or firearms or any other articles of an intrinsically dangerous nature.

16. Furniture, equipment and other large articles may be brought into the Building only at the time and in the manner designated by Landlord. Movements of Tenant's property into or out of the Building and within the Building are entirely at the risk and responsibility of Tenant.

17. Tenant shall notify Landlord in advance of any person or contractor who is engaged by Tenant to do janitorial work, interior window washing, or cleaning in the Premises.

18. Tenant shall not use the Premises for lodging, cooking (except for microwave reheating and coffee makers) or manufacturing or selling any alcoholic beverages or for any illegal purposes.

19. Tenant shall comply with all safety, fire protection and evacuation procedures and regulations established by Landlord or any governmental agency.

20. Tenant shall cooperate and participate in all reasonable security programs affecting the Building.

21. Tenant shall not loiter, eat, drink, sit or lie in the lobby or other public areas in the Building. Tenant shall not go onto the roof of the Building or any other non-public areas of the Building (except the Premises), and Landlord reserves all rights to control the public and non-public areas of the Building (except the Premises). In no event shall Tenant have access to any electrical, telephone, plumbing or other mechanical closets without Landlord's prior written consent.

22. Tenant shall not use the freight or passenger elevators, loading docks or receiving areas of the Building except in accordance with regulations for their use established by Landlord.

23. Tenant shall not dispose of any foreign substances in the toilets, urinals, sinks or other washroom facilities, nor shall Tenant permit such items to be used other than for their intended purposes; and Tenant shall be liable for all damage as a result of a violation of this rule.

24. Tenant shall not permit its employees, invitees or guests to smoke in the Premises or in any other part of the Building, nor shall Tenant permit its employees, invitees or guests to loiter at the Building entrances for the purposes of smoking. Landlord may, but shall not be required to, designate an area for smoking outside the Building.

25. All vehicles are to be currently licensed, in good operating condition, parked for business purposes having to do with Tenant's business operated in the Premises, parked within designated parking spaces, one vehicle to each space. No vehicle shall be parked as a "billboard" vehicle in the Parking Facilities. Any vehicle parked improperly may be towed away. No oversized utility trucks shall be parked in the Parking Facilities. Tenant, Tenant's agents, employees, vendors and customers who do not operate or park their vehicles as required shall subject the vehicle to being towed at the expense of the owner or driver. Landlord may place a "boot" on the vehicle to immobilize it and may levy a charge of $50.00 to remove the "boot."

EXHIBIT C

PARKING

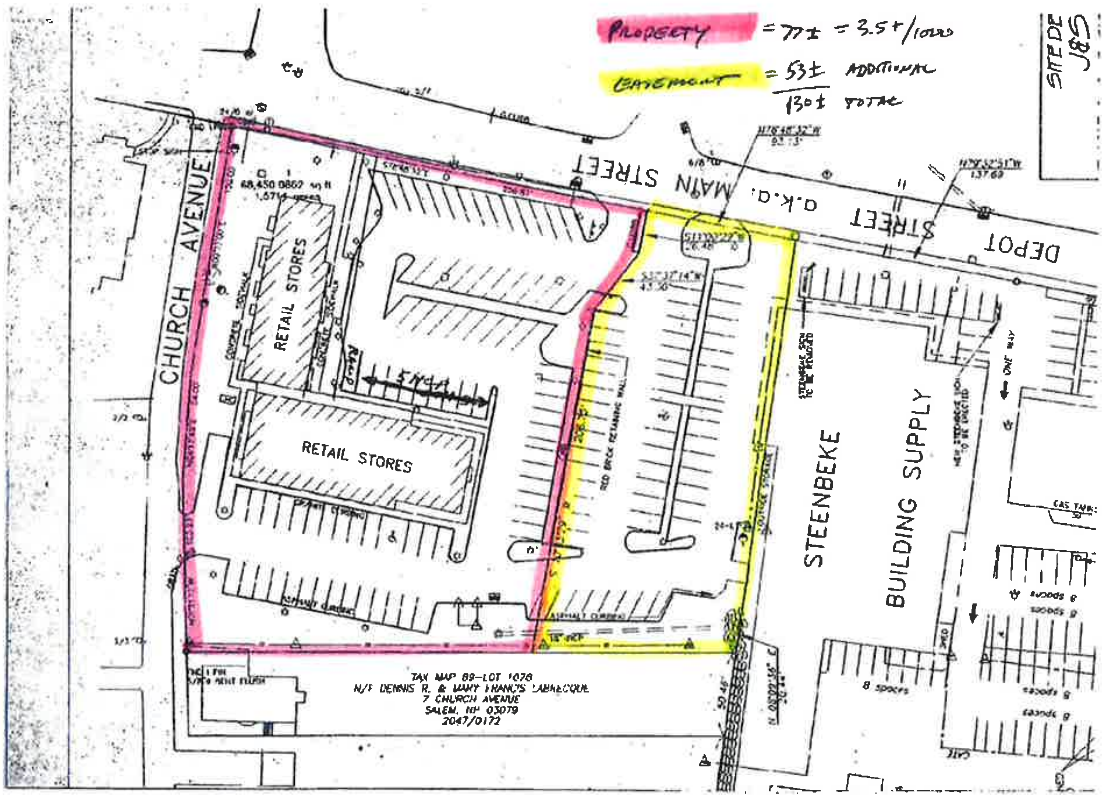
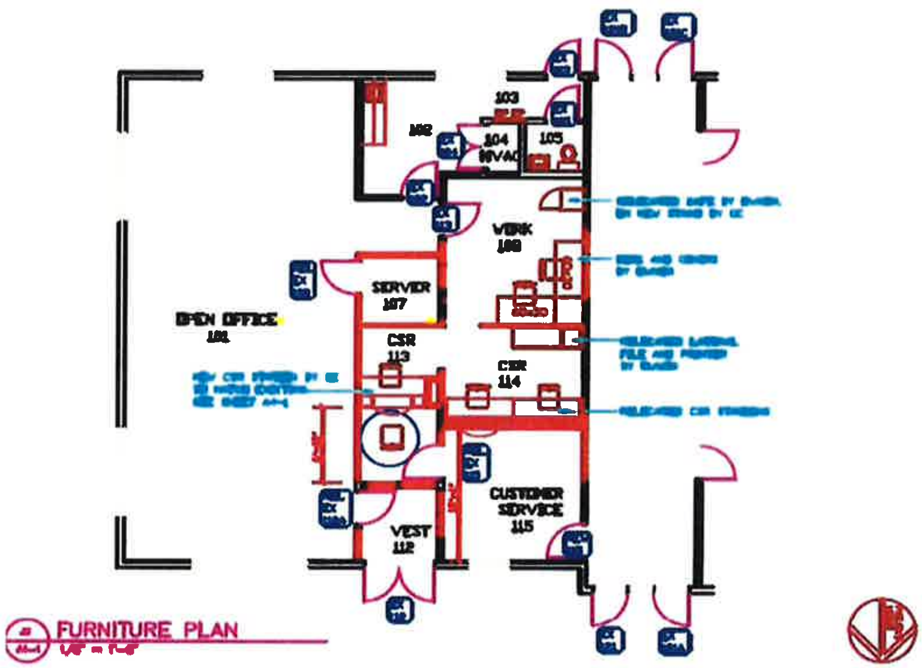


EXHIBIT D

INITIAL ALTERATIONS
(Only including a portion of a set of plans provided to Landlord for review & approval)



Liberty Utilites Lease Extension

These lease extensions are between Liberty Energy Utilities (New Hampshire) Corp. (Lessee), a Delaware corporation having an address of 15 Buttrick Road, Londonderry, NH 03053, and Ciborowski Associates LLC (Lessor) having an address of 18 North Main Street, Suite 202, Concord, NH 03301.

Whereas Lessor and Lessee are parties to a lease for 2,150 square feet of office space on the first floor at 116 North Main Street, Concord, NH, which commenced on December 1, 2016, and expired on November 30, 2021 (Lease 1);

Whereas, Lessee wishes to exercise its option to extend Lease 1 for five years, commencing December 1, 2021, and ending on November 30 1, 2026;

Whereas, Lessor and Lessee are parties to a separate lease for 1,660 square feet of office space on the third floor of 114 North Main Street, Concord, NH, which commenced on September 1, 2017, and expired on November 30, 2021 (Lease 2);

Whereas on or about November 1, 2019, the Parties amended Lease 2 to include an additional 645 square feet of office space on the third floor of 114 North Main Street, Concord, NH, and to adjust the Base Rent;

Whereas Lessee wishes to renew its option to extend Lease 2 as to the 1,660 square feet of office space on the third floor of 114 North Main Street, Concord, NH, but does not wish to extend Lease 2 as to the 645 square feet of office space on the third floor of 114 North Main Street, Concord, NH;

Now Therefore, the parties agree as follows:

1. Lease 1 shall be extended for a five-year term, commencing December 1, 2021, and ending November 30, 2026.

2. Lease 2 shall be extended as to the 1,660 square feet of office space on the third floor of 114 North Main Street, for a five-year term, commencing December 1, 2021, and ending November 30, 2026.

3. Lease 2 shall not be extended as to the 645 square feet of office space on the third floor of 114 North Main Street.

4. The combined Base Rent for the renewals of Lease 1 and Lease 2 as described above shall be as follows:

    a. Rent for the first year beginning December 1, 2021, and ending on November 30, 2022, shall be Thirteen thousand five hundred and fifty dollars ($13,550) per month.
    b. Rent for the second year beginning December 1, 2022, and ending November 30, 2023, shall be Thirteen thousand nine hundred fifty-six dollars and 50 cents ($13,956.50) per month.
    c. Rent for the third year beginning December 1, 2023, and ending November 30, 2024, shall be Fourteen thousand three hundred seventy-five dollars and 20 cents ($14,375.20).
    d. Rent for the fourth year beginning December 1, 2024, and ending November 30, 2025, shall be Fourteen thousand eight hundred six dollars and forty-five cents ($14,806.45) per month.
    e. Rent for the fifth year beginning December 1, 2025, and ending November 30, 2026, shall be Fifteen thousand two hundred fifty dollars and 64 cents ($15,250.64) per month.

5. Lessor is responsible for all real estate taxes for the five-year term of the extended leases. All other terms of Lease 1 and Lease 2 shall remain in effect.

EXECUTED this 30th day of December, 2021

CIBOROWSKI ASSOCIATES, LLC	LIBERTY ENERGY UTILITIES (NEW HAMPSHIRE) CORP.
By: Mark Ciborowski	By: Jody J Allison
Name: Mark Ciborowski	Name: Jody Allison
Title: Owner, Ciborowski Associates LLC	Title: President

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Office of the Consumer Advocate Data Requests - Set 3

Date Request Received: 9/18/23
Request No: OCA 3-66

Date of Response: 10/2/23
Respondent: Kristin Jardin
Daniel Dane

REQUEST:

Intercompany Rent. Refer to Attachment KMJD/DSD-1,Schedule RR-3.8.

a. Provide the address of each facility leased and a detailed explanation of the what these rental expenses pertain to.
b. Provide the amount rental expense by category included in the adjusted test year, each rate year and each of the calendar years 2018, 2019, 2020, 2021 and 2022.

RESPONSE:

a. As described in the response to OCA 3-2, the Londonderry facility located at 15 Buttrick Road, Londonderry, New Hampshire, is used for Granite State Electric and EnergyNorth Natural Gas company office space. The Concord Training Center, located at Broken Bridge Road, Concord, New Hampshire, is a training facility for the Company's gas and electric employees. The E-point location at 130 Main Street in Salem is the current customer service walk-in center. The Ciborowski facility located at 116 N. Main Street in Concord is a leased customer service location and office space for Liberty employees. Granite Center LLC is a parking lot adjacent to the Concord Office (Ciborowski – Concord).
b. Please refer to the tables below for the 2018–2022 lease expense and for the adjusted test year and each rate year. In preparing this response, the Company identified a correction to rental expenses included in RR-3.8 (along with a small adjustment to the amount reported in DOE 4-48). The Company will make a correcting adjustment in its next update to the revenue requirement in this proceeding.

Description of Rent / Lease	2018	2019	2020	2021	2022
Training Center	$ 77,789.24	$ 75,920.12	$ 88,634.76	$ 115,516.76	$ 123,892.76
LONDONDERRY LEASE	54,744.00	56,268.00	57,660.00	63,856.00	54,320.00
Ciborowski - Concord	22,541.82	21,345.30	21,210.62	12,146.34	26,124.50
E-Point LLC - Salem Walk-In					8,657.24
Granite Center LLC - Concord Parking		565.68	873.42	871.61	853.80
Totals	$ 155,075.06	$ 154,099.10	$ 168,378.80	$ 192,390.71	$ 213,848.30

Docket No. DE 23-039 Request No. OCA 3-66

SAP GL Account	G/L Account	FERC Account	Regulatory Acc	Forecast Method	2022 Pro Forma	2022/2023	2023/2024	2024/2025	2025/2026
501300	Meals & Ent	931	Rents—Admin	General Escalator	132,786	134,786	138,084	141,147	144,134
503000	Rental Expense	931	Rents—Admin	Specifically Forecasted	75,009	73,328	77,030	78,739	80,406
503000	Rental Expense	921	Office Splys n Exps	General Escalator	9,872	10,021	10,266	10,494	10,716
				Total [1]	217,667	218,135	225,380	230,380	235,256
[1] Reflects $95 that was incorrectly coded to rental expense.									

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

Department of Energy Data Requests - Set 2

Date Request Received: 6/2/23 Date of Response: 6/12/23
Request No. DOE 2-7 Respondent: Lauren Preston

REQUEST:

Please describe in detail any and all problems or challenges that Liberty has experienced during the implementation if its new customer information and billing system (SAP system) in each of the following categories: 1) Payroll; 2) Vendor Payments; 3) Financial reporting – both internal and external to regulatory agencies and/or consultants such as auditors; 4) preparation and delivery of accurate customer bills on the Company's regular, planned, billing cycles for any and all customer classes and customer sub-types (e.g. residential customers taking default service, those taking competitive supply, net metered customers, group net metered hosts and/or group members, etc.).

RESPONSE:

1. Payroll. The Company experienced minor work order mapping glitches that were corrected immediately by the Hypercare team. These issues did not impact employee pay.
2. Vendor Payments. Vendor payments continued after implementation with few delays. A few construction contractor invoices were paid in duplicate or incorrectly due to a legacy application that did not load properly; this legacy application was used to review and manage approvals of the invoices. An incorrect configuration in SAP was identified and corrected resolving the issue. The incorrect/duplicate payments have also been resolved directly with the vendors.
3. Financial Reporting. The Company experienced some delays in closing the books for the first month and the first quarter in the new system due to the learning curve. These were internal delays that did not impact the Company's ability to report results internally or externally, including providing information to our auditors.

   The Company requested and was granted, an extension to the FERC Form 1 filing deadline as well. The extension request was made in part due to SAP, but also as a result of the same team's involvement in the preparation of the rate case materials, the timing of which coincided with the FERC Form 1 filing. The SAP-related delay for the FERC Form 1 was due to preparing this information from SAP for the first time and the need to learn to run new reports, as well as the team taking time to prepare additional checks to compare to the legacy system reporting from prior quarters.

4. Customer Bills. For regular planned billing cycles, the majority of the customers were successfully billed during the first month of go-live and continue to be. There were delays in cleaning up data anomalies and transactions related to system changes resulting in a backlog of approximately 670 unbilled accounts. The most complicated accounts to resume billing were for the group net metered hosts. Although this was a relatively small number (93), the complexity of billing and data required to provide the information to this group of customers delayed billing. The Company communicated with customers affected by the delays and in all cases offered them extended payment arrangements and excluded them from late payment charges and collections activities due to the delay in billing.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

Department of Energy Data Requests - Set 2

Date Request Received: 6/2/23
Request No. DOE 2-8

Date of Response: 6/12/23
Respondent: Kristin Jardin
Daniel Dane
Gregg Therrien

REQUEST:

Please provide an estimated or actual amount of 2022 distribution revenue that was not billed in 2022 (but was billed or is planned to be billed in 2023) due to the implementation of new SAP customer information and billing system. Please indicate if the temporary rate revenue requirement was adjusted for any such unbilled revenue.

RESPONSE:

The Company cannot easily estimate or quantify the amount of 2022 distribution revenue not billed in 2022 due solely to the implementation of the new SAP customer information and billing system. Principally this is due to the fact that, regardless of the billing system, every year a portion of the prior years' billings are posted in the following year. Typically, this occurs for the higher numbered billing cycles (e.g., Cycles 18 to 20), the meters for which are read near the end of the month. The Company records unbilled revenue to compensate for this recurring effect to accrue revenue in the appropriate calendar month. The temporary rate revenue requirement included unbilled revenue each month.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Technical Session Data Requests - Set 2

Date Request Received: 11/3/23 | Date of Response: 11/20/23
Request No: DOE TS 2-66 | Respondent: Lauren Preston

REQUEST:

Reference Response to DOE 2-7 where, concerning implementation of its new customer information and billing system (SAP system), Liberty states:

"There were delays in cleaning up data anomalies and transactions related to system changes resulting in a backlog of approximately 670 unbilled accounts."

For those 670 backlogged accounts, please provide, by account number, by month, and by year:

a. The customers rate class
b. The amount of revenue not billed on schedule.
c. The dates and amounts when the backlogged or delayed revenue was billed.

RESPONSE:

A summary of the billing resolution by rate class each month is summarized in Confidential Attachment 23-039 DOE TS 2-66, page 1. The detailed list of account numbers is included in Confidential Attachment 23-039 DOE TS 2-66, page 2.

On a monthly basis, the Company calculates an estimate of revenue not billed and operates under a revenue decoupling mechanism, therefore the Company's allowed revenue is not impacted by accounts not billed on schedule. This is not to say that Liberty diminishes in any way the inconvenience to our customers in waiting for an invoice to be released.

The shaded or redacted information in Confidential Attachment 23-039 DOE TS 2-66 and Confidential Attachment 23-039 DOE TS 2-66 is "individual customer data … that can identify, singly or in combination, that specific customer," RSA 363:37, I, and is thus protected from disclosure by RSA 363:38 and RSA 91-A:5, IV. Therefore, pursuant to Puc 203.08(d), the Company has a good faith basis to seek confidential treatment of this information and will submit a motion seeking confidential treatment prior to the final hearing in this docket.

Summary of Delayed Invoices and Resolution by Date and Dollar

	Bill release month (2023) - Dollar value and Number of Accounts														Total #	Total $ by Rate
Rate class	Jan #	Jan $	Feb #	Feb $	Mar #	Mar $	Apr #	Apr $	June #	June $	July #	July $	Aug #	Aug $	by Rate	Class
G1 Large Commercial/ Industrial			1	$29,425.92	1	$51,700.36									2	$ 81,126.28
G2 Medium Commercial/ Industrial	10	$98,633.82	12	$118,308.00	1	$1,609.14	1	$47,473.16			1	$ 3,942.63			25	$ 269,966.75
G3 Small Commercial	51	$101,922.55	35	$55,309.03	1	$11.18	1	$573.20							88	$ 157,815.96
D Residential	259	$78,610.15	196	$98,202.85	7	$3,944.86	3	$1,175.55	1	$43.37			1	$60.97	467	$ 182,037.75
D10 Residential TOU (Time of Use)	4	$1,330.89	2	$1,050.82											6	$ 2,381.71
D11 Battery Storage	3	$572.02	87	$69,951.77	1	$691.78									91	$ 71,215.57
T00 Total Electric Home	2	$5,434.13	2	$2,363.79	1	$7,184.48									5	$ 14,982.40
Total by Month	329	$286,503.56	335	$374,612.18	12	$65,141.80	5	$49,221.91	1	$ 43.37	1	$ 3,942.63	1	$60.97	684	$ 779,526.42

Detailed list by account number of delayed bills post go live

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount		Invoice Date	Month-Yr
1	7000248206	[redacted]	GSER_D	9/22/2022	$	429.59	2/14/2023	Feb-23
2	7000261360		GSER_D	9/22/2022	$	507.50	3/6/2023	Mar-23
3	7000264244		GSER_D	9/22/2022	$	136.13	2/1/2023	Feb-23
4	7000264660		GSER_D	9/22/2022	$	1,322.92	2/25/2023	Feb-23
5	7000273295		GSER_D	9/22/2022	$	2,959.36	1/21/2023	Jan-23
6	7000276691		GSER_D	9/22/2022	$	56.74	2/1/2023	Feb-23
7	7000277915		GSER_D	9/22/2022	$	58.96	2/27/2023	Feb-23
8	7000278675		GSER_D	9/22/2022	$	61.25	2/1/2023	Feb-23
9	7000279793		GSER_D	8/24/2022	$	508.03	2/1/2023	Feb-23
10	7000281249		GSER_D	9/22/2022	$	311.44	2/1/2023	Feb-23
11	7000283480		GSER_D	9/22/2022	$	666.89	1/21/2023	Jan-23
12	7000287278		GSER_D	9/22/2022	$	61.17	2/1/2023	Feb-23
13	7000297872		GSER_D	9/22/2022	$	543.76	2/25/2023	Feb-23
14	7000259670		GSER_D	9/22/2022	$	(370.26)	1/30/2023	Jan-23
15	7000295726		GSEC_G3	9/22/2022	$	71.14	2/1/2023	Feb-23
16	7000293388		GSER_D	9/26/2022	$	2,594.48	1/21/2023	Jan-23
17	7000278008		GSER_D	9/29/2022	$	339.35	2/2/2023	Feb-23
18	7000279282		GSER_D	9/29/2022	$	2,182.57	1/21/2023	Jan-23
19	7000282041		GSER_D	9/29/2022	$	(346.22)	1/26/2023	Jan-23
20	7000274043		GSEC_G2	9/30/2022	$	1,609.14	3/16/2023	Mar-23
21	7000274979		GSER_D	9/30/2022	$	56.16	2/27/2023	Feb-23
22	7000263311		GSER_D	10/7/2022	$	253.38	2/14/2023	Feb-23
23	7000249691		GSER_D	10/7/2022	$	(257.91)	1/26/2023	Jan-23
24	7000274419		GSEC_G3	10/7/2022	$	(704.60)	2/23/2023	Feb-23
25	7000295301		GSEC_G3	10/7/2022	$	253.42	1/21/2023	Jan-23
26	7000265812		GSEC_G2	10/7/2022	$	7,974.75	1/28/2023	Jan-23
27	7000272807		GSEC_G3	10/7/2022	$	11.18	3/17/2023	Mar-23
28	7000267622		GSER_D	10/14/2022	$	15.76	1/24/2023	Jan-23
29	7000269236		GSEC_G3	10/11/2022	$	10,598.86	1/21/2023	Jan-23
30	7000253114		GSER_D	10/11/2022	$	575.40	1/28/2023	Jan-23
31	7000255454		GSER_D	10/12/2022	$	35.15	1/18/2023	Jan-23
32	7000255577		GSER_D	10/11/2022	$	14.74	3/8/2023	Mar-23
33	7000256808		GSER_D	10/11/2022	$	111.82	1/19/2023	Jan-23
34	7000258036		GSER_D	10/11/2022	$	664.10	1/28/2023	Jan-23
35	7000258606		GSER_D	10/11/2022	$	28.82	1/18/2023	Jan-23
36	7000259726		GSER_D	10/11/2022	$	573.76	1/21/2023	Jan-23
37	7000261316		GSER_D	10/11/2022	$	936.48	1/21/2023	Jan-23
38	7000263270		GSER_D	10/11/2022	$	56.61	1/19/2023	Jan-23
39	7000268847		GSER_D	10/11/2022	$	590.11	2/24/2023	Feb-23
40	7000271545		GSER_D	10/11/2022	$	308.70	1/19/2023	Jan-23
41	7000275848		GSER_D	10/11/2022	$	2,508.50	1/28/2023	Jan-23
42	7000276367		GSER_D	10/12/2022	$	688.91	1/26/2023	Jan-23
43	7000277017		GSER_D	10/11/2022	$	236.32	1/19/2023	Jan-23
44	7000281905		GSER_D	10/6/2022	$	397.02	2/6/2023	Feb-23
45	7000283317		GSER_D	10/11/2022	$	39.74	1/19/2023	Jan-23
46	7000285580		GSER_D	10/11/2022	$	104.34	3/10/2023	Mar-23
47	7000287249		GSER_D	10/11/2022	$	251.57	1/19/2023	Jan-23
48	7000287825		GSER_D	10/11/2022	$	527.37	2/24/2023	Feb-23
49	7000288730		GSER_D	10/12/2022	$	201.72	1/19/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
50	7000288757	[redacted]	GSER_D	10/11/2022	$ 58.24	1/19/2023	Jan-23
51	7000292387		GSER_D	10/3/2022	$ 87.74	2/1/2023	Feb-23
52	7000294844		GSER_D	10/12/2022	$ 132.60	1/19/2023	Jan-23
53	7000295212		GSER_D	10/11/2022	$ 699.29	1/21/2023	Jan-23
54	7000296812		GSER_D	10/11/2022	$ 40.51	1/18/2023	Jan-23
55	7000260321		GSEC_G3	10/11/2022	$ 14,205.44	1/21/2023	Jan-23
56	7000277946		GSER_D	10/11/2022	$ 15.72	1/25/2023	Jan-23
57	7000298244		GSER_D	10/7/2022	$ 66.02	1/19/2023	Jan-23
58	7000301689		GSER_D	10/12/2022	$ 262.67	2/24/2023	Feb-23
59	7000302027		GSER_D	10/12/2022	$ 103.55	1/19/2023	Jan-23
60	7000306704		GSER_D	10/12/2022	$ 358.38	1/21/2023	Jan-23
61	7000306830		GSER_D	10/12/2022	$ 565.07	1/21/2023	Jan-23
62	7000273968		GSEC_G3	10/11/2022	$ 2,946.78	1/21/2023	Jan-23
63	7000283548		GSEC_G3	10/11/2022	$ 618.43	1/28/2023	Jan-23
64	7000293001		GSEC_G3	10/11/2022	$ 32.02	1/19/2023	Jan-23
65	7000307957		GSEC_G2	10/11/2022	$ 22,913.57	1/21/2023	Jan-23
66	7000296222		GSER_D	10/11/2022	$ 69.32	1/19/2023	Jan-23
67	7000264228		GSEC_G3	10/11/2022	$ 6,681.81	1/21/2023	Jan-23
68	7000265407		GSEC_G3	10/11/2022	$ (2,599.67)	2/7/2023	Feb-23
69	7000306837		GSEC_G2	10/11/2022	$ 1,135.16	1/25/2023	Jan-23
70	7000248762		GSEC_G2	10/11/2022	$ 575.52	1/19/2023	Jan-23
71	7000288794		GSEC_G3	10/11/2022	$ 473.76	1/19/2023	Jan-23
72	7000295725		GSEC_G3	10/11/2022	$ 356.41	1/21/2023	Jan-23
73	7000248838		GSER_D	10/12/2022	$ 553.30	2/8/2023	Feb-23
74	7000251619		GSER_D	10/12/2022	$ 223.90	1/25/2023	Jan-23
75	7000251931		GSER_D	10/12/2022	$ 78.02	1/25/2023	Jan-23
76	7000257128		GSER_D	10/12/2022	$ 23.27	1/24/2023	Jan-23
77	7000258831		GSER_D	10/12/2022	$ 28.33	1/25/2023	Jan-23
78	7000264759		GSER_D	10/12/2022	$ 914.16	2/27/2023	Feb-23
79	7000264786		GSER_D	10/12/2022	$ 96.00	1/25/2023	Jan-23
80	7000265878		GSER_D	10/12/2022	$ 37.76	1/25/2023	Jan-23
81	7000266476		GSER_D	10/12/2022	$ 531.54	2/1/2023	Feb-23
82	7000268421		GSER_D	10/12/2022	$ 36.11	1/24/2023	Jan-23
83	7000268865		GSER_D	10/12/2022	$ 507.19	2/24/2023	Feb-23
84	7000268944		GSER_D	10/12/2022	$ 182.94	1/25/2023	Jan-23
85	7000269244		GSER_D	10/12/2022	$ 32.54	1/25/2023	Jan-23
86	7000269587		GSER_D	10/12/2022	$ 43.37	6/16/2023	Jun-23
87	7000269669		GSER_D	9/15/2022	$ 43.27	1/25/2023	Jan-23
88	7000269892		GSER_D	10/12/2022	$ 24.57	1/24/2023	Jan-23
89	7000270737		GSER_D	10/12/2022	$ 244.59	1/25/2023	Jan-23
90	7000270741		GSER_D	10/12/2022	$ 668.21	2/24/2023	Feb-23
91	7000271592		GSER_D	9/19/2022	$ 397.69	2/21/2023	Feb-23
92	7000274659		GSER_D	10/12/2022	$ 16.33	1/25/2023	Jan-23
93	7000274737		GSER_D	10/12/2022	$ 258.08	1/21/2023	Jan-23
94	7000275383		GSER_D	10/12/2022	$ 27.08	1/25/2023	Jan-23
95	7000278321		GSER_D	10/12/2022	$ 132.70	1/24/2023	Jan-23
96	7000282836		GSER_D	10/12/2022	$ 38.88	1/24/2023	Jan-23
97	7000283743		GSER_D	10/12/2022	$ 824.39	2/27/2023	Feb-23
98	7000283895		GSER_D	10/3/2022	$ 39.72	1/24/2023	Jan-23
99	7000294203		GSER_D	10/13/2022	$ 2,081.02	1/28/2023	Jan-23
100	7000295558		GSER_D	10/12/2022	$ 101.45	1/25/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
101	7000295761	[redacted]	GSER_D	10/12/2022	$ 10.43	1/24/2023	Jan-23
102	7000295844	[redacted]	GSER_D	10/12/2022	$ 223.50	1/25/2023	Jan-23
103	7000296538	[redacted]	GSER_D	10/12/2022	$ 30.59	1/24/2023	Jan-23
104	7000298084	[redacted]	GSER_D	10/12/2022	$ 8.02	1/24/2023	Jan-23
105	7000299098	[redacted]	GSER_D	10/13/2022	$ 752.40	2/27/2023	Feb-23
106	7000299719	[redacted]	GSER_D	10/12/2022	$ 35.27	1/24/2023	Jan-23
107	7000299949	[redacted]	GSER_D	10/12/2022	$ 37.17	1/26/2023	Jan-23
108	7000301912	[redacted]	GSER_D	10/12/2022	$ 70.91	1/25/2023	Jan-23
109	7000302220	[redacted]	GSER_D	10/12/2022	$ 36.11	1/25/2023	Jan-23
110	7000302748	[redacted]	GSER_D	10/12/2022	$ 70.20	1/25/2023	Jan-23
111	7000303100	[redacted]	GSER_D	10/12/2022	$ 38.71	1/30/2023	Jan-23
112	7000303751	[redacted]	GSER_D	10/12/2022	$ 76.83	3/6/2023	Mar-23
113	7000303804	[redacted]	GSER_D	10/12/2022	$ 23.57	1/24/2023	Jan-23
114	7000304099	[redacted]	GSER_D	10/12/2022	$ 326.83	2/24/2023	Feb-23
115	7000304112	[redacted]	GSER_D	10/5/2022	$ 40.68	2/27/2023	Feb-23
116	7000304574	[redacted]	GSER_D	10/12/2022	$ 75.14	1/26/2023	Jan-23
117	7000306532	[redacted]	GSER_D	10/12/2022	$ 29.12	1/24/2023	Jan-23
118	7000306663	[redacted]	GSER_D	10/3/2022	$ 58.31	1/23/2023	Jan-23
119	7000306810	[redacted]	GSER_D	10/12/2022	$ 47.95	1/24/2023	Jan-23
120	7000265205	[redacted]	GSEC_G2	10/12/2022	$ 47,473.16	4/21/2023	Apr-23
121	7000265400	[redacted]	GSEC_G3	10/12/2022	$ 196.97	2/8/2023	Feb-23
122	7000272714	[redacted]	GSEC_G2	9/19/2022	$ 11,847.27	1/21/2023	Jan-23
123	7000283394	[redacted]	GSEC_G3	10/12/2022	$ 297.01	2/24/2023	Feb-23
124	7000285117	[redacted]	GSEC_G3	10/12/2022	$ 1,180.63	2/24/2023	Feb-23
125	7000289613	[redacted]	GSEC_G2	10/12/2022	$ 38,727.57	1/21/2023	Jan-23
126	7000291259	[redacted]	GSEC_G3	10/12/2022	$ 8,422.70	1/21/2023	Jan-23
127	7000298276	[redacted]	GSER_D	10/13/2022	$ 1,278.96	2/25/2023	Feb-23
128	7000299118	[redacted]	GSEC_G3	10/12/2022	$ 312.08	1/25/2023	Jan-23
129	7000299557	[redacted]	GSEC_G3	10/12/2022	$ 1,748.11	1/21/2023	Jan-23
130	7000300682	[redacted]	GSER_D	10/12/2022	$ 1,406.97	2/25/2023	Feb-23
131	7000303404	[redacted]	GSEC_G3	10/12/2022	$ 170.77	1/25/2023	Jan-23
132	7000303670	[redacted]	GSEC_G3	10/12/2022	$ 1,115.00	1/25/2023	Jan-23
133	7000303740	[redacted]	GSEC_G2	10/12/2022	$ 828.31	1/25/2023	Jan-23
134	7000303762	[redacted]	GSEC_G2	10/12/2022	$ 1,098.43	1/25/2023	Jan-23
135	7000304631	[redacted]	GSEC_G3	10/12/2022	$ 573.20	4/17/2023	Apr-23
136	7000305362	[redacted]	GSEC_G3	10/12/2022	$ 3,108.06	2/27/2023	Feb-23
137	7000305384	[redacted]	GSEC_G3	10/12/2022	$ 2,102.91	2/27/2023	Feb-23
138	7000306942	[redacted]	GSEC_G3	10/12/2022	$ 2,244.83	2/27/2023	Feb-23
139	7000254994	[redacted]	GSEC_G2	10/12/2022	$ 685.95	2/25/2023	Feb-23
140	7000248557	[redacted]	GSEC_G2	10/12/2022	$ 7,573.58	2/24/2023	Feb-23
141	7000248843	[redacted]	GSEC_G3	10/12/2022	$ 133.82	1/24/2023	Jan-23
142	7000289431	[redacted]	GSEC_G3	10/12/2022	$ 16,058.15	1/21/2023	Jan-23
143	7000263867	[redacted]	GSEC_G2	10/12/2022	$ 9,764.01	2/24/2023	Feb-23
144	7000303308	[redacted]	GSEC_G3	10/12/2022	$ 270.25	1/25/2023	Jan-23
145	7000304196	[redacted]	GSEC_G3	10/12/2022	$ 512.03	1/25/2023	Jan-23
146	7000307787	[redacted]	GSEC_G3	10/12/2022	$ 203.00	1/25/2023	Jan-23
147	7000298293	[redacted]	GSEC_G3	10/12/2022	$ 306.91	1/25/2023	Jan-23
148	7000305340	[redacted]	GSEC_G3	10/12/2022	$ 353.69	1/25/2023	Jan-23
149	7000299854	[redacted]	GSEC_G3	10/12/2022	$ 336.74	1/25/2023	Jan-23
150	7000299095	[redacted]	GSEC_G3	10/12/2022	$ 396.79	1/25/2023	Jan-23
151	7000299072	[redacted]	GSEC_G3	10/12/2022	$ 315.09	1/25/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
152	7000304893	[redacted]	GSEC_G2	10/12/2022	$ 2,171.43	1/21/2023	Jan-23
153	7000260873		GSER_D	10/14/2022	$ 1,815.66	2/25/2023	Feb-23
154	7000265328		GSER_D	10/14/2022	$ 50.32	1/25/2023	Jan-23
155	7000268290		GSER_D	10/14/2022	$ 135.46	1/25/2023	Jan-23
156	7000268862		GSER_D	10/14/2022	$ 47.18	1/25/2023	Jan-23
157	7000269328		GSER_D	10/14/2022	$ 198.79	2/21/2023	Feb-23
158	7000276311		GSER_D	10/14/2022	$ 159.90	2/1/2023	Feb-23
159	7000279839		GSER_D	10/14/2022	$ 52.07	1/25/2023	Jan-23
160	7000281633		GSER_D	10/14/2022	$ 70.91	1/25/2023	Jan-23
161	7000273938		GSER_D10	10/14/2022	$ 150.05	1/24/2023	Jan-23
162	7000283329		GSER_D	10/14/2022	$ 44.22	2/11/2023	Feb-23
163	7000284276		GSER_D	10/14/2022	$ 4,493.33	1/21/2023	Jan-23
164	7000292313		GSER_D	10/14/2022	$ 86.25	2/27/2023	Feb-23
165	7000294442		GSER_T	10/14/2022	$ 7,184.48	3/2/2023	Mar-23
166	7000291975		GSEC_G3	10/14/2022	$ 366.67	1/21/2023	Jan-23
167	7000295158		GSER_D	9/21/2022	$ 1,564.03	1/31/2023	Jan-23
168	7000250908		GSER_D	10/18/2022	$ 135.76	1/27/2023	Jan-23
169	7000276670		GSER_D	10/18/2022	$ 84.07	1/27/2023	Jan-23
170	7000296353		GSER_D	10/18/2022	$ 877.41	1/28/2023	Jan-23
171	7000273056		GSER_D	10/18/2022	$ 111.59	1/27/2023	Jan-23
172	7000267753		GSEC_G3	10/18/2022	$ 5.55	2/1/2023	Feb-23
173	7000269902		GSEC_G3	10/18/2022	$ 25,290.96	2/27/2023	Feb-23
174	7000281415		GSER_D	10/17/2022	$ 51.65	1/27/2023	Jan-23
175	7000290901		GSER_D	10/17/2022	$ 91.57	1/24/2023	Jan-23
176	7000252702		GSEC_G3	10/19/2022	$ 101.96	2/9/2023	Feb-23
177	7000260039		GSEC_G1	9/23/2022	$ 51,700.36	3/24/2023	Mar-23
178	7000262617		GSER_D	10/20/2022	$ 145.36	1/31/2023	Jan-23
179	7000279578		GSEC_G3	10/20/2022	$ 14,433.91	2/27/2023	Feb-23
180	7000297290		GSER_D	10/20/2022	$ 705.13	2/27/2023	Feb-23
181	7000299792		GSER_D	10/20/2022	$ 387.57	2/24/2023	Feb-23
182	7000299796		GSER_D	10/20/2022	$ 1,081.50	2/25/2023	Feb-23
183	7000302406		GSER_D	10/20/2022	$ 1,630.27	2/25/2023	Feb-23
184	7000254331		GSER_D	10/17/2022	$ 11.41	1/27/2023	Jan-23
185	7000257318		GSER_D	10/17/2022	$ 9.45	1/27/2023	Jan-23
186	7000269478		GSER_D	10/17/2022	$ 161.70	1/27/2023	Jan-23
187	7000288193		GSER_D	10/17/2022	$ 30.24	1/27/2023	Jan-23
188	7000292567		GSER_D	10/17/2022	$ 18.21	2/11/2023	Feb-23
189	7000265634		GSEC_G3	10/17/2022	$ 7.75	1/27/2023	Jan-23
190	7000246958		GSEC_G3	10/21/2022	$ 94.83	1/31/2023	Jan-23
191	7000254628		GSER_D	9/29/2022	$ 17.08	2/16/2023	Feb-23
192	7000299739		GSER_D	10/16/2022	$ 932.77	2/27/2023	Feb-23
193	7000307207		GSEC_G2	9/29/2022	$ 4,692.68	2/3/2023	Feb-23
194	7000253317		GSER_D	10/17/2022	$ 33.49	1/27/2023	Jan-23
195	7000260646		GSER_D	10/18/2022	$ 23.49	1/27/2023	Jan-23
196	7000270157		GSER_D	10/17/2022	$ 73.57	1/30/2023	Jan-23
197	7000275440		GSER_D	10/17/2022	$ 96.63	1/27/2023	Jan-23
198	7000256696		GSER_D11	9/30/2022	$ 916.50	2/9/2023	Feb-23
199	7000269878		GSER_D11	9/30/2022	$ 210.60	1/28/2023	Jan-23
200	7000278123		GSER_D	9/30/2022	$ 969.83	4/20/2023	Apr-23
201	7000278889		GSER_D11	9/30/2022	$ 337.21	1/28/2023	Jan-23
202	7000283422		GSER_D11	9/30/2022	$ 275.23	2/6/2023	Feb-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
203	7000283457	[redacted]	GSER_D11	9/30/2022	$ 246.77	2/6/2023	Feb-23
204	7000283712		GSER_D11	9/30/2022	$ 418.58	2/6/2023	Feb-23
205	7000296516		GSER_D11	9/30/2022	$ 279.96	2/9/2023	Feb-23
206	7000305314		GSER_D11	9/30/2022	$ 395.11	2/6/2023	Feb-23
207	7000259030		GSER_D	10/17/2022	$ 32.37	2/11/2023	Feb-23
208	7000273436		GSER_D	10/17/2022	$ 32.70	1/27/2023	Jan-23
209	7000276274		GSER_D	10/17/2022	$ 38.56	1/27/2023	Jan-23
210	7000285294		GSER_D	10/17/2022	$ 11.58	1/27/2023	Jan-23
211	7000289974		GSER_D10	10/17/2022	$ 48.89	1/27/2023	Jan-23
212	7000299906		GSER_D	10/17/2022	$ 18.08	1/27/2023	Jan-23
213	7000254059		GSER_D	10/31/2022	$ 0.49	1/19/2023	Jan-23
214	7000294372		GSER_D	10/24/2022	$ 96.12	2/2/2023	Feb-23
215	7000254575		GSEC_G2	10/26/2022	$ 3,668.72	2/24/2023	Feb-23
216	7000262977		GSER_D	10/26/2022	$ 86.02	2/2/2023	Feb-23
217	7000264922		GSER_D	10/26/2022	$ 109.39	2/2/2023	Feb-23
218	7000285029		GSEC_G3	10/26/2022	$ (2,541.78)	2/9/2023	Feb-23
219	7000290214		GSER_T	10/26/2022	$ 263.74	2/17/2023	Feb-23
220	7000289521		GSEC_G2	10/26/2022	$ 41,182.51	2/27/2023	Feb-23
221	7000304510		GSER_D	10/17/2022	$ 81.55	1/27/2023	Jan-23
222	7000263012		GSER_D	10/17/2022	$ 144.37	1/27/2023	Jan-23
223	7000276844		GSER_D	10/17/2022	$ 66.46	1/27/2023	Jan-23
224	7000277363		GSER_D	10/17/2022	$ 20.69	2/11/2023	Feb-23
225	7000298269		GSEC_G3	10/24/2022	$ 5.55	2/1/2023	Feb-23
226	7000299716		GSEC_G3	10/24/2022	$ 5.55	2/6/2023	Feb-23
227	7000300500		GSEC_G3	10/24/2022	$ 5.55	2/1/2023	Feb-23
228	7000307748		GSEC_G3	10/24/2022	$ 6.18	2/1/2023	Feb-23
229	7000308046		GSEC_G3	10/24/2022	$ 111.24	2/1/2023	Feb-23
230	7000292669		GSER_D	10/28/2022	$ 263.62	2/3/2023	Feb-23
231	7000296142		GSER_D	10/28/2022	$ 1,810.29	2/27/2023	Feb-23
232	7000281867		GSEC_G2	10/28/2022	$ 3,370.68	2/27/2023	Feb-23
233	7000258485		GSER_D	10/24/2022	$ 25.79	1/25/2023	Jan-23
234	7000303807		GSER_D	10/31/2022	$ 18.21	1/25/2023	Jan-23
235	7000272871		GSER_D	11/4/2022	$ 0.98	2/1/2023	Feb-23
236	7000254216		GSEC_G3	10/17/2022	$ 223.41	1/27/2023	Jan-23
237	7000303694		GSER_D	10/17/2022	$ 48.30	1/25/2023	Jan-23
238	7000247254		GSER_D	11/1/2022	$ 59.69	1/18/2023	Jan-23
239	7000255989		GSER_D	11/1/2022	$ 68.32	1/18/2023	Jan-23
240	7000258183		GSER_D	11/1/2022	$ 33.93	1/18/2023	Jan-23
241	7000266328		GSER_D	11/1/2022	$ 103.39	1/18/2023	Jan-23
242	7000267862		GSER_D	10/5/2022	$ 429.59	2/27/2023	Feb-23
243	7000274169		GSER_D	11/1/2022	$ 706.24	1/28/2023	Jan-23
244	7000246284		GSEC_G3	11/1/2022	$ 390.21	1/28/2023	Jan-23
245	7000264513		GSEC_G3	11/1/2022	$ 163.81	1/21/2023	Jan-23
246	7000276343		GSER_D	11/1/2022	$ 76.09	2/24/2023	Feb-23
247	7000283225		GSER_D10	11/1/2022	$ 348.46	2/24/2023	Feb-23
248	7000292556		GSER_D	11/1/2022	$ 51.12	1/18/2023	Jan-23
249	7000253571		GSER_D	11/1/2022	$ 82.05	1/18/2023	Jan-23
250	7000283798		GSER_D10	11/1/2022	$ 813.67	1/26/2023	Jan-23
251	7000293436		GSEC_G2	11/1/2022	$ 3,942.63	7/10/2023	Jul-23
252	7000287945		GSER_D	10/24/2022	$ 7.36	2/24/2023	Feb-23
253	7000303897		GSEC_G3	10/17/2022	$ 66.46	1/24/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
254	7000300116	[redacted]	GSEC_G3	10/17/2022	$ 113.43	1/25/2023	Jan-23
255	7000298093		GSEC_G3	10/17/2022	$ 94.72	1/25/2023	Jan-23
256	7000298070		GSEC_G3	10/17/2022	$ 1,031.59	1/25/2023	Jan-23
257	7000254008		GSER_D	10/19/2022	$ 63.71	1/25/2023	Jan-23
258	7000276827		GSER_D	10/24/2022	$ 64.34	2/11/2023	Feb-23
259	7000253408		GSER_D	11/3/2022	$ 1,985.04	1/28/2023	Jan-23
260	7000255150		GSER_D	11/3/2022	$ 228.89	2/9/2023	Feb-23
261	7000259598		GSER_D	11/3/2022	$ 2,213.82	1/28/2023	Jan-23
262	7000273796		GSEC_G3	10/12/2022	$ (591.72)	2/24/2023	Feb-23
263	7000260087		GSEC_G2	11/3/2022	$ 26,280.17	2/11/2023	Feb-23
264	7000278567		GSER_D	11/3/2022	$ 257.47	2/27/2023	Feb-23
265	7000301227		GSER_D	10/17/2022	$ 125.08	1/30/2023	Jan-23
266	7000274072		GSEC_G3	11/9/2022	$ 0.56	1/19/2023	Jan-23
267	7000292230		GSER_D	10/17/2022	$ 42.47	1/30/2023	Jan-23
268	7000254248		GSER_D	11/9/2022	$ 17.23	1/19/2023	Jan-23
269	7000277941		GSER_D	10/24/2022	$ 167.18	2/2/2023	Feb-23
270	7000261891		GSER_D	11/10/2022	$ 43.67	1/25/2023	Jan-23
271	7000300110		GSER_D	11/10/2022	$ 6.99	1/25/2023	Jan-23
272	7000250909		GSER_D	10/24/2022	$ 105.87	2/1/2023	Feb-23
273	7000278029		GSER_D	10/17/2022	$ 134.39	1/26/2023	Jan-23
274	7000278159		GSER_D	11/10/2022	$ 25.67	1/30/2023	Jan-23
275	7000283691		GSER_D	11/4/2022	$ 141.06	1/26/2023	Jan-23
276	7000299926		GSER_D	11/10/2022	$ 14.95	1/25/2023	Jan-23
277	7000301384		GSER_D	11/10/2022	$ 5.54	1/25/2023	Jan-23
278	7000298966		GSER_D	10/24/2022	$ 36.60	2/2/2023	Feb-23
279	7000267918		GSER_D	10/11/2022	$ 2,406.57	3/2/2023	Mar-23
280	7000268334		GSER_D	11/7/2022	$ 817.98	1/28/2023	Jan-23
281	7000297055		GSEC_G2	11/7/2022	$ 12,046.15	2/27/2023	Feb-23
282	7000305959		GSEC_G1	10/14/2022	$ 29,425.92	2/7/2023	Feb-23
283	7000294490		GSER_D	10/17/2022	$ 52.72	1/27/2023	Jan-23
284	7000294828		GSER_D	10/17/2022	$ 108.56	1/27/2023	Jan-23
285	7000295036		GSER_D	10/17/2022	$ 51.10	1/27/2023	Jan-23
286	7000273713		GSER_D	10/29/2022	$ 57.56	1/19/2023	Jan-23
287	7000283247		GSER_D	11/1/2022	$ 51.88	1/19/2023	Jan-23
288	7000271198		GSER_D	10/24/2022	$ 67.94	2/2/2023	Feb-23
289	7000288291		GSER_D	10/24/2022	$ 176.36	2/2/2023	Feb-23
290	7000295464		GSER_D	10/24/2022	$ 314.63	2/2/2023	Feb-23
291	7000250176		GSER_D	11/10/2022	$ 59.53	1/20/2023	Jan-23
292	7000252197		GSER_D	11/9/2022	$ 136.75	1/19/2023	Jan-23
293	7000254170		GSER_D	11/9/2022	$ 82.90	1/20/2023	Jan-23
294	7000256035		GSER_D	11/9/2022	$ 23.47	1/19/2023	Jan-23
295	7000258894		GSER_D	11/9/2022	$ 106.57	1/19/2023	Jan-23
296	7000260350		GSER_D	11/9/2022	$ 80.60	1/19/2023	Jan-23
297	7000260848		GSER_D	11/9/2022	$ 81.15	1/23/2023	Jan-23
298	7000261364		GSER_D	11/9/2022	$ 205.39	1/20/2023	Jan-23
299	7000263105		GSER_D	11/9/2022	$ 39.08	1/20/2023	Jan-23
300	7000264001		GSER_D	11/9/2022	$ 113.39	1/19/2023	Jan-23
301	7000264414		GSER_D	11/9/2022	$ 220.54	1/28/2023	Jan-23
302	7000264587		GSER_D	11/9/2022	$ 62.14	1/20/2023	Jan-23
303	7000265688		GSER_D	11/9/2022	$ 20.23	1/20/2023	Jan-23
304	7000266433		GSER_D	11/9/2022	$ 53.06	1/20/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
305	7000266627	[redacted]	GSER_D	11/9/2022	$ 29.95	1/19/2023	Jan-23
306	7000266939		GSER_D	11/9/2022	$ 91.48	1/20/2023	Jan-23
307	7000266962		GSER_D	11/9/2022	$ 137.74	1/20/2023	Jan-23
308	7000268539		GSER_D	11/9/2022	$ 190.32	1/19/2023	Jan-23
309	7000268652		GSER_D	11/9/2022	$ 23.10	1/19/2023	Jan-23
310	7000276292		GSER_D	11/9/2022	$ 112.08	1/19/2023	Jan-23
311	7000277013		GSER_D	11/9/2022	$ 84.77	1/19/2023	Jan-23
312	7000279799		GSER_D	11/9/2022	$ 1,259.21	1/28/2023	Jan-23
313	7000281515		GSER_D	11/9/2022	$ 66.13	1/23/2023	Jan-23
314	7000281541		GSER_D	11/9/2022	$ 165.00	2/14/2023	Feb-23
315	7000281879		GSER_D	11/9/2022	$ 51.07	1/21/2023	Jan-23
316	7000282319		GSER_D	11/9/2022	$ 54.79	1/30/2023	Jan-23
317	7000282719		GSER_D	11/9/2022	$ 120.82	1/19/2023	Jan-23
318	7000283039		GSER_D	11/9/2022	$ 34.51	1/19/2023	Jan-23
319	7000283744		GSER_D	11/9/2022	$ 111.31	2/27/2023	Feb-23
320	7000284631		GSER_D	11/9/2022	$ 131.22	2/11/2023	Feb-23
321	7000286755		GSER_D	11/9/2022	$ 27.69	1/20/2023	Jan-23
322	7000287067		GSER_D	11/9/2022	$ 730.96	1/20/2023	Jan-23
323	7000287070		GSER_D	11/9/2022	$ 79.77	1/19/2023	Jan-23
324	7000287676		GSER_D	11/9/2022	$ 98.49	1/20/2023	Jan-23
325	7000288040		GSER_D	11/9/2022	$ 19.72	4/7/2023	Apr-23
326	7000288939		GSER_D	11/9/2022	$ 73.46	1/20/2023	Jan-23
327	7000289210		GSER_D	11/9/2022	$ 29.31	1/20/2023	Jan-23
328	7000291600		GSER_D	11/9/2022	$ 14.02	1/19/2023	Jan-23
329	7000291789		GSER_D	11/9/2022	$ 121.86	1/23/2023	Jan-23
330	7000292985		GSER_D	11/9/2022	$ 40.67	1/20/2023	Jan-23
331	7000294207		GSER_D	11/9/2022	$ 68.23	1/19/2023	Jan-23
332	7000295775		GSER_D	11/9/2022	$ 64.76	1/20/2023	Jan-23
333	7000296484		GSER_D	11/9/2022	$ 104.65	1/20/2023	Jan-23
334	7000251120		GSEC_G3	11/9/2022	$ 54.28	2/23/2023	Feb-23
335	7000298895		GSER_D	11/9/2022	$ 181.58	1/20/2023	Jan-23
336	7000302269		GSER_D	11/9/2022	$ 175.44	1/20/2023	Jan-23
337	7000305434		GSER_D	10/17/2022	$ 1,174.00	2/28/2023	Feb-23
338	7000305456		GSER_D	10/17/2022	$ 774.61	2/22/2023	Feb-23
339	7000305500		GSER_D	10/17/2022	$ 87.00	3/2/2023	Mar-23
340	7000305522		GSER_D	10/17/2022	$ 1,013.89	2/22/2023	Feb-23
341	7000305544		GSER_D	10/17/2022	$ 418.82	2/27/2023	Feb-23
342	7000305566		GSER_D	10/17/2022	$ 1,028.10	2/28/2023	Feb-23
343	7000305588		GSER_D	10/17/2022	$ 481.10	2/28/2023	Feb-23
344	7000305610		GSER_D	10/17/2022	$ 1,395.96	2/28/2023	Feb-23
345	7000305632		GSER_D	10/17/2022	$ 798.85	2/28/2023	Feb-23
346	7000305654		GSER_D	10/17/2022	$ 737.98	2/28/2023	Feb-23
347	7000305698		GSER_D	10/17/2022	$ 747.88	3/23/2023	Mar-23
348	7000305720		GSER_D	10/17/2022	$ 976.91	2/28/2023	Feb-23
349	7000305742		GSER_D	10/17/2022	$ 791.16	2/28/2023	Feb-23
350	7000305764		GSER_D	10/17/2022	$ 441.16	2/28/2023	Feb-23
351	7000305786		GSER_D	10/17/2022	$ 838.46	2/28/2023	Feb-23
352	7000305808		GSER_D	10/17/2022	$ 1,061.34	2/28/2023	Feb-23
353	7000305830		GSER_D	10/17/2022	$ 1,026.99	2/28/2023	Feb-23
354	7000305852		GSER_D	10/17/2022	$ 488.26	2/28/2023	Feb-23
355	7000305896		GSER_D	10/17/2022	$ 746.50	2/28/2023	Feb-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
356	7000305918	[redacted]	GSER_D	10/17/2022	$ 825.26	2/28/2023	Feb-23
357	7000305940		GSER_D	10/17/2022	$ 743.31	2/28/2023	Feb-23
358	7000305962		GSER_D	10/17/2022	$ 763.19	2/28/2023	Feb-23
359	7000305984		GSER_D	10/17/2022	$ 442.12	2/28/2023	Feb-23
360	7000306006		GSER_D	10/17/2022	$ 784.05	2/28/2023	Feb-23
361	7000306028		GSER_D	10/17/2022	$ 688.07	2/28/2023	Feb-23
362	7000306050		GSER_D	10/17/2022	$ 941.43	2/28/2023	Feb-23
363	7000306072		GSER_D	10/17/2022	$ 1,015.87	2/28/2023	Feb-23
364	7000306094		GSER_D	10/17/2022	$ 800.61	2/28/2023	Feb-23
365	7000306116		GSER_D	10/17/2022	$ 852.64	2/28/2023	Feb-23
366	7000306138		GSER_D	10/17/2022	$ 1,086.66	2/28/2023	Feb-23
367	7000306160		GSER_D	10/17/2022	$ 671.30	2/28/2023	Feb-23
368	7000306182		GSER_D	10/17/2022	$ 663.83	2/28/2023	Feb-23
369	7000306204		GSER_D	10/17/2022	$ 935.93	2/28/2023	Feb-23
370	7000306226		GSER_D	10/17/2022	$ 567.82	2/28/2023	Feb-23
371	7000306248		GSER_D	10/17/2022	$ 98.85	2/28/2023	Feb-23
372	7000308228		GSER_D	10/31/2022	$ 1,064.60	2/28/2023	Feb-23
373	7000261198		GSER_D	11/10/2022	$ 9.77	1/25/2023	Jan-23
374	7000295654		GSER_D	11/9/2022	$ 23.26	2/7/2023	Feb-23
375	7000275577		GSEC_G3	11/9/2022	$ 667.50	1/20/2023	Jan-23
376	7000286816		GSEC_G3	11/9/2022	$ 10.79	1/19/2023	Jan-23
377	7000256522		GSER_D	11/9/2022	$ 23.12	1/20/2023	Jan-23
378	7000296114		GSEC_G3	11/9/2022	$ 665.69	1/28/2023	Jan-23
379	7000263420		GSEC_G3	10/14/2022	$ 11,816.54	1/30/2023	Jan-23
380	7000287890		GSEC_G3	11/9/2022	$ 257.57	1/20/2023	Jan-23
381	7000249358		GSER_D	11/10/2022	$ 196.16	1/26/2023	Jan-23
382	7000251073		GSER_D	11/10/2022	$ 3.44	1/25/2023	Jan-23
383	7000251359		GSER_D	11/10/2022	$ 189.76	1/28/2023	Jan-23
384	7000258719		GSER_D	11/10/2022	$ 46.20	1/26/2023	Jan-23
385	7000258909		GSER_D	11/10/2022	$ 26.74	1/26/2023	Jan-23
386	7000259507		GSER_D	11/10/2022	$ 186.00	4/12/2023	Apr-23
387	7000260600		GSER_D	11/10/2022	$ 34.67	1/25/2023	Jan-23
388	7000260860		GSER_D	11/10/2022	$ 30.32	1/30/2023	Jan-23
389	7000261172		GSER_D	11/10/2022	$ 27.62	1/25/2023	Jan-23
390	7000261379		GSER_D	10/31/2022	$ 47.32	1/26/2023	Jan-23
391	7000264205		GSER_D	11/10/2022	$ 88.93	1/24/2023	Jan-23
392	7000265427		GSER_D	11/10/2022	$ 21.97	1/25/2023	Jan-23
393	7000265531		GSER_D	11/10/2022	$ 21.03	1/26/2023	Jan-23
394	7000266779		GSER_D	10/18/2022	$ 595.49	1/26/2023	Jan-23
395	7000270256		GSER_D	11/10/2022	$ 11.07	1/25/2023	Jan-23
396	7000273229		GSER_D	11/10/2022	$ 75.58	1/25/2023	Jan-23
397	7000275539		GSER_D	11/10/2022	$ 28.49	1/26/2023	Jan-23
398	7000279381		GSER_D	11/10/2022	$ 1,126.80	1/28/2023	Jan-23
399	7000283153		GSER_D	10/26/2022	$ 188.74	2/11/2023	Feb-23
400	7000285571		GSER_D	11/10/2022	$ 14.53	1/26/2023	Jan-23
401	7000287313		GSER_D	11/10/2022	$ 1,739.13	1/28/2023	Jan-23
402	7000289107		GSER_D	11/10/2022	$ 226.84	1/26/2023	Jan-23
403	7000294619		GSER_D	11/10/2022	$ 60.97	8/31/2023	Aug-23
404	7000294826		GSER_D	11/10/2022	$ 45.96	1/30/2023	Jan-23
405	7000294898		GSER_D	11/10/2022	$ 96.32	1/25/2023	Jan-23
406	7000297090		GSER_D	11/10/2022	$ 26.43	1/26/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
407	7000299972	[redacted]	GSER_D	11/10/2022	$ 47.97	1/26/2023	Jan-23
408	7000301560		GSER_D	11/10/2022	$ 43.43	1/26/2023	Jan-23
409	7000303364		GSER_D	11/10/2022	$ 19.99	1/26/2023	Jan-23
410	7000306246		GSER_D	11/10/2022	$ 49.45	1/26/2023	Jan-23
411	7000306444		GSER_D	11/10/2022	$ 48.50	1/26/2023	Jan-23
412	7000265439		GSEC_G2	10/18/2022	$ 11,361.81	1/21/2023	Jan-23
413	7000271594		GSEC_G3	11/10/2022	$ 2,491.33	1/28/2023	Jan-23
414	7000284779		GSEC_G3	11/10/2022	$ 153.54	1/26/2023	Jan-23
415	7000271120		GSER_D	10/24/2022	$ 204.29	2/2/2023	Feb-23
416	7000285025		GSER_D	11/10/2022	$ 99.00	1/26/2023	Jan-23
417	7000258523		GSER_D	11/10/2022	$ 146.03	2/25/2023	Feb-23
418	7000262627		GSER_D	10/18/2022	$ 498.32	2/11/2023	Feb-23
419	7000288119		GSEC_G3	10/18/2022	$ 1,263.23	1/23/2023	Jan-23
420	7000260366		GSER_D	11/10/2022	$ 432.08	1/25/2023	Jan-23
421	7000296277		GSER_D	11/15/2022	$ 14.77	1/27/2023	Jan-23
422	7000290909		GSEC_G3	10/17/2022	$ 9,014.26	1/28/2023	Jan-23
423	7000249420		GSER_D	11/15/2022	$ 107.89	1/28/2023	Jan-23
424	7000249859		GSER_D	10/17/2022	$ 370.91	1/28/2023	Jan-23
425	7000250601		GSER_D	11/15/2022	$ 384.44	2/11/2023	Feb-23
426	7000252384		GSER_D	10/17/2022	$ 58.96	2/24/2023	Feb-23
427	7000252979		GSER_D	10/17/2022	$ 1,194.86	2/25/2023	Feb-23
428	7000255813		GSER_D	11/15/2022	$ 194.25	1/28/2023	Jan-23
429	7000258541		GSER_D	11/15/2022	$ 42.20	2/23/2023	Feb-23
430	7000260880		GSER_D	11/15/2022	$ 199.56	1/28/2023	Jan-23
431	7000261526		GSER_D	11/15/2022	$ 62.14	1/28/2023	Jan-23
432	7000262936		GSER_D	10/17/2022	$ 985.54	2/27/2023	Feb-23
433	7000263950		GSER_D	11/15/2022	$ 1,756.92	1/28/2023	Jan-23
434	7000264025		GSER_D	11/15/2022	$ 271.65	1/28/2023	Jan-23
435	7000265647		GSER_D	11/15/2022	$ 354.61	1/31/2023	Jan-23
436	7000265949		GSER_D	11/15/2022	$ 68.43	1/28/2023	Jan-23
437	7000266183		GSER_D	11/15/2022	$ 1,744.18	2/10/2023	Feb-23
438	7000266518		GSER_D	11/15/2022	$ 2,165.59	1/28/2023	Jan-23
439	7000266685		GSER_D	10/17/2022	$ 731.06	1/21/2023	Jan-23
440	7000267613		GSER_D	11/15/2022	$ 235.09	1/27/2023	Jan-23
441	7000267845		GSER_D	11/15/2022	$ 17.28	1/27/2023	Jan-23
442	7000268729		GSER_D	10/17/2022	$ 544.69	2/24/2023	Feb-23
443	7000268757		GSER_D	10/18/2022	$ 917.56	2/25/2023	Feb-23
444	7000268806		GSER_D	11/15/2022	$ 1,117.53	1/28/2023	Jan-23
445	7000269511		GSER_D	11/15/2022	$ 64.40	1/28/2023	Jan-23
446	7000270447		GSER_D	11/15/2022	$ 119.60	2/2/2023	Feb-23
447	7000272166		GSER_D	11/15/2022	$ 849.04	1/28/2023	Jan-23
448	7000272866		GSER_D	11/15/2022	$ 118.08	1/27/2023	Jan-23
449	7000272916		GSER_D	11/2/2022	$ 39.25	1/27/2023	Jan-23
450	7000276088		GSER_D	10/17/2022	$ 221.42	2/22/2023	Feb-23
451	7000276401		GSER_D	11/15/2022	$ 32.10	1/31/2023	Jan-23
452	7000276700		GSER_D	11/15/2022	$ 422.88	1/31/2023	Jan-23
453	7000276869		GSER_D	11/15/2022	$ 89.21	1/28/2023	Jan-23
454	7000276960		GSER_D	11/15/2022	$ 190.35	1/28/2023	Jan-23
455	7000278016		GSER_D	10/17/2022	$ 570.05	2/24/2023	Feb-23
456	7000278090		GSER_D	11/15/2022	$ 79.79	1/28/2023	Jan-23
457	7000278792		GSER_D	11/15/2022	$ 287.35	1/27/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
458	7000280482	[redacted]	GSER_D	10/17/2022	$ 799.70	2/7/2023	Feb-23
459	7000282069		GSER_D	11/15/2022	$ 100.75	1/28/2023	Jan-23
460	7000284271		GSER_D	10/17/2022	$ 809.88	2/27/2023	Feb-23
461	7000285366		GSER_D	11/15/2022	$ 1,455.42	2/9/2023	Feb-23
462	7000286312		GSER_D	10/17/2022	$ 1,053.90	2/25/2023	Feb-23
463	7000286631		GSER_D	10/17/2022	$ 146.52	2/22/2023	Feb-23
464	7000286659		GSER_D	11/15/2022	$ 56.61	1/28/2023	Jan-23
465	7000290559		GSER_D	10/17/2022	$ 281.95	1/21/2023	Jan-23
466	7000290722		GSER_D	11/15/2022	$ 4,413.67	1/28/2023	Jan-23
467	7000293347		GSER_D	10/17/2022	$ 401.58	1/28/2023	Jan-23
468	7000293424		GSER_D	11/15/2022	$ 32.42	1/31/2023	Jan-23
469	7000294075		GSER_D	11/15/2022	$ 170.15	1/27/2023	Jan-23
470	7000294880		GSER_D	11/15/2022	$ 1,537.63	1/28/2023	Jan-23
471	7000295270		GSER_D	10/17/2022	$ 478.60	1/21/2023	Jan-23
472	7000257744		GSEC_G2	10/17/2022	$ 5,118.48	2/24/2023	Feb-23
473	7000258267		GSEC_G3	10/17/2022	$ 1,393.27	2/24/2023	Feb-23
474	7000262087		GSEC_G3	11/15/2022	$ 32.72	1/27/2023	Jan-23
475	7000268754		GSER_T	10/17/2022	$ 2,793.95	1/21/2023	Jan-23
476	7000272788		GSER_T	11/15/2022	$ 2,640.18	1/28/2023	Jan-23
477	7000273102		GSER_T	10/17/2022	$ 2,100.05	2/25/2023	Feb-23
478	7000297572		GSER_D	10/17/2022	$ 405.15	2/24/2023	Feb-23
479	7000298245		GSER_D	10/20/2022	$ 760.56	2/27/2023	Feb-23
480	7000299175		GSER_D	10/17/2022	$ 418.27	2/2/2023	Feb-23
481	7000300305		GSER_D	10/17/2022	$ 1,152.89	2/27/2023	Feb-23
482	7000306075		GSER_D	10/17/2022	$ 1,498.25	2/25/2023	Feb-23
483	7000306150		GSER_D	10/17/2022	$ 706.82	2/25/2023	Feb-23
484	7000306239		GSER_D	10/17/2022	$ 489.01	2/24/2023	Feb-23
485	7000306844		GSER_D	10/17/2022	$ 809.24	2/25/2023	Feb-23
486	7000306907		GSER_D	10/17/2022	$ 878.00	2/27/2023	Feb-23
487	7000308153		GSER_D	10/17/2022	$ 368.77	2/24/2023	Feb-23
488	7000276156		GSEC_G3	10/17/2022	$ 1,641.97	2/24/2023	Feb-23
489	7000289412		GSEC_G3	10/17/2022	$ 66.64	2/24/2023	Feb-23
490	7000308158		GSEC_G3	10/17/2022	$ 159.90	2/24/2023	Feb-23
491	7000260882		GSER_D	11/15/2022	$ 67.65	1/27/2023	Jan-23
492	7000294438		GSER_D	11/15/2022	$ 198.67	1/28/2023	Jan-23
493	7000267179		GSER_D	11/15/2022	$ 185.37	1/31/2023	Jan-23
494	7000270131		GSER_D	10/20/2022	$ 621.60	2/15/2023	Feb-23
495	7000272978		GSER_D	10/17/2022	$ 163.56	2/25/2023	Feb-23
496	7000308131		GSER_D	11/15/2022	$ 51.54	1/27/2023	Jan-23
497	7000250211		GSEC_G3	11/15/2022	$ 467.39	1/28/2023	Jan-23
498	7000276104		GSEC_G3	11/15/2022	$ 1,906.45	1/28/2023	Jan-23
499	7000278365		GSEC_G2	10/17/2022	$ 1,383.75	2/7/2023	Feb-23
500	7000304829		GSEC_G3	10/17/2022	$ 287.17	2/25/2023	Feb-23
501	7000287101		GSER_D	11/15/2022	$ 9.46	1/27/2023	Jan-23
502	7000266656		GSER_D	11/18/2022	$ 28.47	1/19/2023	Jan-23
503	7000281039		GSER_D	10/24/2022	$ 17.67	2/2/2023	Feb-23
504	7000276280		GSER_D	11/16/2022	$ 841.14	2/4/2023	Feb-23
505	7000277352		GSEC_G2	10/25/2022	$ 2,541.37	2/14/2023	Feb-23
506	7000295093		GSEC_G3	10/27/2022	$ 11.15	2/11/2023	Feb-23
507	7000287770		GSEC_G3	11/16/2022	$ (207.92)	2/9/2023	Feb-23
508	7000289947		GSER_D	11/15/2022	$ 17.72	1/25/2023	Jan-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
509	7000290640	[redacted]	GSER_D	11/14/2022	$ 32.55	1/19/2023	Jan-23
510	7000296909		GSER_D	10/24/2022	$ 615.62	2/2/2023	Feb-23
511	7000288647		GSER_D	10/24/2022	$ 180.36	2/2/2023	Feb-23
512	7000248031		GSER_D	11/22/2022	$ 34.27	2/2/2023	Feb-23
513	7000248421		GSER_D	10/24/2022	$ 1,225.82	2/27/2023	Feb-23
514	7000248910		GSER_D	11/22/2022	$ 119.97	2/2/2023	Feb-23
515	7000253103		GSER_D	11/22/2022	$ 34.48	2/2/2023	Feb-23
516	7000253796		GSER_D	11/22/2022	$ 29.48	2/3/2023	Feb-23
517	7000256419		GSER_D	10/24/2022	$ 1,615.97	1/21/2023	Jan-23
518	7000257690		GSER_D	11/22/2022	$ 868.13	1/26/2023	Jan-23
519	7000259824		GSER_D	11/22/2022	$ 57.39	2/2/2023	Feb-23
520	7000262086		GSER_D	10/24/2022	$ 245.81	1/21/2023	Jan-23
521	7000262350		GSER_D	11/22/2022	$ 31.04	2/2/2023	Feb-23
522	7000265576		GSER_D	10/24/2022	$ 486.67	2/24/2023	Feb-23
523	7000265892		GSER_D	10/24/2022	$ 216.32	1/19/2023	Jan-23
524	7000266324		GSER_D	11/22/2022	$ 18.85	2/2/2023	Feb-23
525	7000266356		GSER_D	10/24/2022	$ 479.85	2/24/2023	Feb-23
526	7000272165		GSER_D	11/22/2022	$ 53.31	2/2/2023	Feb-23
527	7000275323		GSER_D	10/24/2022	$ 2,516.47	1/28/2023	Jan-23
528	7000275531		GSER_D	11/22/2022	$ 106.54	2/2/2023	Feb-23
529	7000275765		GSER_D	10/24/2022	$ 3,666.39	1/28/2023	Jan-23
530	7000276025		GSER_D	11/22/2022	$ 29.79	2/2/2023	Feb-23
531	7000276155		GSER_D	11/22/2022	$ 578.39	2/3/2023	Feb-23
532	7000277243		GSER_D	11/22/2022	$ 693.82	1/25/2023	Jan-23
533	7000277435		GSER_D	11/22/2022	$ 55.26	2/2/2023	Feb-23
534	7000277681		GSER_D	10/24/2022	$ 1,253.73	1/21/2023	Jan-23
535	7000278649		GSER_D	10/24/2022	$ 365.97	2/25/2023	Feb-23
536	7000279791		GSER_D	11/22/2022	$ 79.47	2/2/2023	Feb-23
537	7000280597		GSER_D	10/24/2022	$ 523.48	2/24/2023	Feb-23
538	7000287763		GSER_D	10/24/2022	$ 329.29	2/1/2023	Feb-23
539	7000294131		GSER_D	10/24/2022	$ 301.85	2/27/2023	Feb-23
540	7000297177		GSER_D	10/24/2022	$ 958.43	2/27/2023	Feb-23
541	7000297782		GSER_D	10/24/2022	$ 322.50	2/2/2023	Feb-23
542	7000297923		GSER_D	10/24/2022	$ 621.92	2/24/2023	Feb-23
543	7000298079		GSER_D	10/24/2022	$ 308.10	2/24/2023	Feb-23
544	7000298153		GSER_D	10/24/2022	$ 298.27	2/27/2023	Feb-23
545	7000298163		GSER_D	10/24/2022	$ 88.76	2/15/2023	Feb-23
546	7000298280		GSER_D	10/24/2022	$ 473.73	2/24/2023	Feb-23
547	7000298429		GSER_D	10/24/2022	$ 654.14	2/24/2023	Feb-23
548	7000298529		GSER_D	11/13/2022	$ 73.95	2/2/2023	Feb-23
549	7000298981		GSER_D	10/24/2022	$ 792.03	2/25/2023	Feb-23
550	7000299154		GSER_D	11/22/2022	$ 648.38	1/23/2023	Jan-23
551	7000299690		GSER_D	10/24/2022	$ 754.61	2/27/2023	Feb-23
552	7000299788		GSER_D	10/24/2022	$ 424.94	2/24/2023	Feb-23
553	7000299970		GSER_D	10/24/2022	$ 689.68	2/24/2023	Feb-23
554	7000300016		GSER_D	10/24/2022	$ 306.59	2/24/2023	Feb-23
555	7000300598		GSER_D	10/24/2022	$ 674.91	2/24/2023	Feb-23
556	7000301263		GSER_D	10/24/2022	$ 706.16	2/25/2023	Feb-23
557	7000301381		GSER_D	10/24/2022	$ 162.20	2/27/2023	Feb-23
558	7000301743		GSER_D	10/27/2022	$ 535.45	2/24/2023	Feb-23
559	7000302652		GSER_D	10/24/2022	$ 742.58	2/25/2023	Feb-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
560	7000276624	[redacted]	GSEC_G3	11/22/2022	$ 1,914.20	1/23/2023	Jan-23
561	7000285237		GSEC_G3	10/24/2022	$ 4,249.20	2/27/2023	Feb-23
562	7000298676		GSER_D10	10/24/2022	$ 702.36	2/27/2023	Feb-23
563	7000299787		GSEC_G3	11/22/2022	$ 56.07	2/2/2023	Feb-23
564	7000303102		GSEC_G3	11/22/2022	$ 1,760.57	2/6/2023	Feb-23
565	7000303378		GSER_D	10/27/2022	$ 234.30	2/27/2023	Feb-23
566	7000304265		GSER_D	10/24/2022	$ 226.97	2/24/2023	Feb-23
567	7000304566		GSER_D	10/24/2022	$ 618.09	2/24/2023	Feb-23
568	7000304698		GSER_D	10/24/2022	$ 639.03	2/24/2023	Feb-23
569	7000305127		GSER_D	10/24/2022	$ 267.75	2/27/2023	Feb-23
570	7000305157		GSER_D	10/24/2022	$ 380.91	2/24/2023	Feb-23
571	7000305187		GSER_D	10/24/2022	$ 451.28	2/24/2023	Feb-23
572	7000305254		GSER_D	10/24/2022	$ 322.01	2/27/2023	Feb-23
573	7000305732		GSER_D	10/24/2022	$ 873.26	2/25/2023	Feb-23
574	7000306221		GSER_D	10/24/2022	$ 296.01	2/27/2023	Feb-23
575	7000307483		GSER_D	10/27/2022	$ 392.02	2/24/2023	Feb-23
576	7000307626		GSER_D	10/24/2022	$ 387.93	2/24/2023	Feb-23
577	7000278940		GSER_D	10/24/2022	$ 647.50	2/25/2023	Feb-23
578	7000282882		GSER_D	11/22/2022	$ 878.33	2/6/2023	Feb-23
579	7000282986		GSEC_G3	11/22/2022	$ 190.90	2/10/2023	Feb-23
580	7000306921		GSER_D	10/24/2022	$ 246.27	2/25/2023	Feb-23
581	7000262587		GSEC_G3	11/22/2022	$ 1,032.55	2/3/2023	Feb-23
582	7000297971		GSEC_G3	10/24/2022	$ 60.92	2/25/2023	Feb-23
583	7000257502		GSER_D	11/14/2022	$ 195.00	1/25/2023	Jan-23
584	7000264372		GSER_D	11/15/2022	$ 188.01	1/25/2023	Jan-23
585	7000248725		GSER_D10	11/14/2022	$ 318.28	1/26/2023	Jan-23
586	7000247299		GSER_D11	10/31/2022	$ 830.72	2/10/2023	Feb-23
587	7000247647		GSER_D11	10/31/2022	$ 1,566.66	2/10/2023	Feb-23
588	7000248070		GSER_D11	10/31/2022	$ 176.39	2/1/2023	Feb-23
589	7000248224		GSER_D11	10/31/2022	$ 849.13	2/10/2023	Feb-23
590	7000248427		GSER_D11	10/31/2022	$ 787.71	2/10/2023	Feb-23
591	7000250723		GSER_D11	10/31/2022	$ 346.27	2/1/2023	Feb-23
592	7000251168		GSER_D11	10/31/2022	$ 1,097.59	2/9/2023	Feb-23
593	7000252037		GSER_D11	10/31/2022	$ 518.77	2/1/2023	Feb-23
594	7000253587		GSER_D11	10/31/2022	$ 745.66	2/10/2023	Feb-23
595	7000254441		GSER_D11	10/31/2022	$ 24.21	1/19/2023	Jan-23
596	7000256730		GSER_D11	10/31/2022	$ 582.34	2/1/2023	Feb-23
597	7000256748		GSER_D11	10/31/2022	$ 1,001.58	2/9/2023	Feb-23
598	7000258624		GSER_D11	10/31/2022	$ 1,100.03	2/10/2023	Feb-23
599	7000260025		GSER_D11	10/31/2022	$ 826.31	2/10/2023	Feb-23
600	7000260102		GSER_D11	10/31/2022	$ 1,110.36	2/10/2023	Feb-23
601	7000260699		GSER_D11	10/31/2022	$ 637.87	2/1/2023	Feb-23
602	7000260800		GSER_D	10/31/2022	$ 80.50	2/1/2023	Feb-23
603	7000260805		GSER_D11	10/31/2022	$ 3,097.86	2/10/2023	Feb-23
604	7000261074		GSER_D11	10/31/2022	$ 983.54	2/9/2023	Feb-23
605	7000261143		GSER_D11	10/31/2022	$ 1,142.37	2/10/2023	Feb-23
606	7000262544		GSER_D11	10/31/2022	$ 1,930.31	2/10/2023	Feb-23
607	7000263476		GSER_D11	10/31/2022	$ 788.01	2/10/2023	Feb-23
608	7000264134		GSER_D11	10/31/2022	$ 722.51	2/10/2023	Feb-23
609	7000264415		GSER_D11	10/31/2022	$ 1,100.88	2/10/2023	Feb-23
610	7000264705		GSER_D11	10/31/2022	$ 1,013.69	2/9/2023	Feb-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
611	7000264940	[redacted]	GSER_D11	10/31/2022	$ 2,721.75	2/7/2023	Feb-23
612	7000265412		GSER_D11	10/31/2022	$ 2,159.27	2/10/2023	Feb-23
613	7000265655		GSER_D11	10/31/2022	$ 639.29	2/1/2023	Feb-23
614	7000265719		GSER_D11	10/31/2022	$ 444.24	2/1/2023	Feb-23
615	7000266058		GSER_D11	10/31/2022	$ 262.60	2/1/2023	Feb-23
616	7000266204		GSER_D11	10/31/2022	$ 519.60	2/1/2023	Feb-23
617	7000267249		GSER_D11	10/31/2022	$ 247.36	2/1/2023	Feb-23
618	7000267392		GSER_D11	10/31/2022	$ 980.71	2/10/2023	Feb-23
619	7000269374		GSER_D11	10/31/2022	$ 478.99	2/1/2023	Feb-23
620	7000269656		GSER_D11	10/31/2022	$ 404.29	2/1/2023	Feb-23
621	7000270228		GSER_D11	10/31/2022	$ 532.70	2/1/2023	Feb-23
622	7000271257		GSER_D11	10/31/2022	$ 897.42	2/9/2023	Feb-23
623	7000272131		GSER_D11	10/31/2022	$ 805.76	2/7/2023	Feb-23
624	7000273455		GSER_D11	10/31/2022	$ 1,388.24	2/10/2023	Feb-23
625	7000274810		GSER_D11	10/31/2022	$ (37.24)	2/7/2023	Feb-23
626	7000275336		GSER_D11	10/31/2022	$ 1,433.38	2/10/2023	Feb-23
627	7000275452		GSER_D11	10/31/2022	$ 933.29	2/10/2023	Feb-23
628	7000275488		GSER_D11	10/31/2022	$ 1,296.17	2/10/2023	Feb-23
629	7000275736		GSER_D11	10/31/2022	$ 855.43	2/9/2023	Feb-23
630	7000276513		GSER_D11	10/31/2022	$ 388.17	2/1/2023	Feb-23
631	7000277043		GSER_D11	10/31/2022	$ 1,082.35	2/10/2023	Feb-23
632	7000277460		GSER_D11	10/31/2022	$ 441.53	2/1/2023	Feb-23
633	7000277652		GSER_D	10/31/2022	$ 113.43	2/1/2023	Feb-23
634	7000277944		GSER_D11	10/31/2022	$ 434.57	2/1/2023	Feb-23
635	7000278668		GSER_D11	10/31/2022	$ 691.71	2/7/2023	Feb-23
636	7000278794		GSER_D11	10/31/2022	$ 359.42	2/10/2023	Feb-23
637	7000279941		GSER_D11	10/31/2022	$ 455.40	2/1/2023	Feb-23
638	7000281283		GSER_D11	10/31/2022	$ 842.65	2/10/2023	Feb-23
639	7000282430		GSER_D11	10/31/2022	$ 418.54	2/10/2023	Feb-23
640	7000282735		GSER_D11	10/31/2022	$ 340.23	2/1/2023	Feb-23
641	7000283291		GSER_D11	10/31/2022	$ 531.72	2/1/2023	Feb-23
642	7000283569		GSER_D11	10/31/2022	$ 521.78	2/1/2023	Feb-23
643	7000283925		GSER_D11	10/31/2022	$ 569.76	2/1/2023	Feb-23
644	7000287047		GSER_D11	10/31/2022	$ 414.40	2/1/2023	Feb-23
645	7000287723		GSER_D11	10/31/2022	$ 321.12	2/1/2023	Feb-23
646	7000287957		GSER_D11	10/31/2022	$ 766.44	2/10/2023	Feb-23
647	7000288128		GSER_D11	10/31/2022	$ 691.78	3/3/2023	Mar-23
648	7000288583		GSER_D11	10/31/2022	$ 470.23	2/1/2023	Feb-23
649	7000289189		GSER_D11	10/31/2022	$ 1,436.14	2/10/2023	Feb-23
650	7000289458		GSER_D11	10/31/2022	$ 694.85	2/10/2023	Feb-23
651	7000290152		GSER_D11	10/31/2022	$ 1,068.18	2/9/2023	Feb-23
652	7000290281		GSER_D11	10/31/2022	$ 1,094.59	2/9/2023	Feb-23
653	7000291568		GSER_D11	10/31/2022	$ 816.70	2/11/2023	Feb-23
654	7000292182		GSER_D11	10/31/2022	$ 698.45	2/11/2023	Feb-23
655	7000292506		GSER_D11	10/31/2022	$ 942.49	2/10/2023	Feb-23
656	7000293150		GSER_D11	10/31/2022	$ 446.58	2/1/2023	Feb-23
657	7000293712		GSER_D11	10/31/2022	$ 452.15	2/1/2023	Feb-23
658	7000293851		GSER_D11	10/31/2022	$ 345.46	2/1/2023	Feb-23
659	7000296129		GSER_D11	10/31/2022	$ 933.99	2/9/2023	Feb-23
660	7000296263		GSER_D11	10/31/2022	$ 1,592.52	2/10/2023	Feb-23
661	7000296743		GSER_D11	10/31/2022	$ 425.03	2/1/2023	Feb-23

Line No	Installat.	Contract Account Number	Rate Category	Last Bill Date	Total Bill Amount	Invoice Date	Month-Yr
662	7000296769	[redacted]	GSER_D11	10/31/2022	$ 994.89	2/10/2023	Feb-23
663	7000297038		GSER_D11	10/31/2022	$ 1,152.95	2/10/2023	Feb-23
664	7000297672		GSER_D11	10/31/2022	$ 1,250.59	2/10/2023	Feb-23
665	7000299947		GSER_D11	10/31/2022	$ 613.39	2/1/2023	Feb-23
666	7000303000		GSER_D11	10/31/2022	$ 1,512.81	2/10/2023	Feb-23
667	7000304555		GSER_D11	10/31/2022	$ 412.01	2/1/2023	Feb-23
668	7000307392		GSER_D11	10/31/2022	$ 522.27	2/1/2023	Feb-23
669	7000261627		GSER_D11	10/31/2022	$ 142.13	2/1/2023	Feb-23
670	7000262286		GSER_D11	10/31/2022	$ 901.62	2/10/2023	Feb-23
671	7000298667		GSER_D	11/17/2022	$ 58.16	1/26/2023	Jan-23
672	7000271248		GSER_D	11/23/2022	$ 24.05	2/2/2023	Feb-23
673	7000275888		GSER_D	11/15/2022	$ 75.04	1/26/2023	Jan-23
674	7000273031		GSEC_G3	11/18/2022	$ 23.48	1/31/2023	Jan-23
675	7000292424		GSEC_G3	10/31/2022	$ 1,621.58	1/26/2023	Jan-23
676	7000296474		GSER_D	11/23/2022	$ 98.55	2/2/2023	Feb-23
677	7000265450		GSER_D	11/30/2022	$ 11.22	1/20/2023	Jan-23
678	7000307997		GSER_D	11/15/2022	$ 41.97	1/20/2023	Jan-23
679	7000258307		GSEC_G3	11/14/2022	$ 240.78	1/26/2023	Jan-23
680	7000304193		GSER_D	11/2/2022	$ 1,237.83	2/27/2023	Feb-23
681	7000284077		GSEC_G3	11/7/2022	$ 1,822.13	2/1/2023	Feb-23
682	7000301089		GSER_D	12/2/2022	$ 39.83	1/26/2023	Jan-23
683	7000277558		GSER_D	11/14/2022	$ 311.74	1/26/2023	Jan-23
684	7000265706		GSER_D	11/23/2022	$ 37.82	2/2/2023	Feb-23

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Office of the Consumer Advocate Technical Session Data Requests - Set 1

Date Request Received: 10/31/23
Request No: OCA TS 1-11

Date of Response: 11/14/23
Respondent: Kristin Jardin
Daniel Dane

REQUEST:

Office-related Expenses:

Refer to the Attachment to OCA 3-104, tab RR 2.10, line 82. Please explain what expenses are included in this account, explain the increase in spending in 2022 over the prior years shown and why it is expected to increase in the rate years.

RESPONSE:

Schedule RR-2.10, line 82, includes general office supply expenses in the test year. Due to the migration from Great Plains ("GP"), however, general office supply expenses for the years 2018 through 2021 are also reflected in other account balances.

Specifically, the costs included on Schedule RR-2.10, line 82 (502700-10921000), for 2018-2021 included office supply expenses previously recorded in GP accounts ending in 5130-9215, plus training costs previously recorded in GP accounts ending in 5131-9215 and did not include office supply expenses previously recorded in GP accounts ending in 5130-9210 and 5131-9210. The costs in the accounts ending in 9210 were instead reported on line 61 (500400-10921000) Materials and Supplies. The training costs for 2018-2021, which were included in error in office supply expenses on line 82, were reported in the Test Year in Schedule RR 2.10, line 85 (503110-10921000).

A restatement of the line items described above is included below. The overall expenses levels, however, did not change.

RESTATED	2018	2019	2020	2021	2022 RR
500400-10921000	$ -	$ -	$ -	$ -	$ 9,908
502700-10921000	213,948	226,495	346,431	388,087	318,867
503110-10921000	46,611	69,084	31,848	50,154	38,256
Total - Restated	$ 260,559	$ 295,579	$ 378,279	$ 438,241	$ 367,031

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Office of the Consumer Advocate Technical Session Data Requests - Set 1

Date Request Received: 10/31/23
Request No: OCA TS 1-12

Date of Response: 11/14/23
Respondent: Kristin Jardin
Daniel Dane

REQUEST:

Meals and Entertainment:

Refer to the Attachment to OCA 3-104, tab RR 2.10, line 148. Please explain what expenses are included in this account, explain the increase in spending in 2022 over the prior years shown and why it is expected to increase in the rate years.

RESPONSE:

Schedule RR 2.10, line 148 does not report meals and entertainment expenses; instead this line reports certain lease expenses for the period January–September 2022 that were previously recorded in Great Plains ("GP") account 6125-9310. The GP to SAP mapping incorrectly converted the GP costs to account 501300-10931000; the correct GL account is 503000-10931000. The response to OCA 3-104, which provided costs for the years 2018 through 2021, reported the Lease Expense on line 149 (503000-10931000), which also includes the October-December 2022 Lease Expense cost of $71,285. The total intercompany lease costs for 2022 were $204,071 ($132,786 (line 148) + $71,285 (a portion of line 149[1])).

[1] The remainder of line 149 is related to other rent expense.

Erica L. Menard
Senior Director, Rates and Regulatory Affairs
15 Buttrick Rd.
Londonderry, NH 03053
603-361-3475
Erica.Menard@libertyutilities.com

January 28, 2023

Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Monthly Disconnection and Accounts Receivable Report — December 2022

Pursuant to Puc 1203.20, enclosed for filing please find Liberty's Monthly Disconnection and Accounts Receivable Report. Please note that most of the low/zero activity in October is due to Liberty's transition to SAP, a new financial and billing system. For example, since SAP does not assess late penalties on a customer's first bill, and since the new billing system went live in October 2022, the new system treats the first monthly bill to be on November 1. Also, no collections activity occurred in October due to the implementation of the new billing system.

Please note this report has been filed via the Commission's Electronic Report Filing system. Thank you for your attention to this matter. Please do not hesitate to call if you have any questions.

Sincerely,

Erica L Menard

Erica L. Menard

Enclosure

Cc: OCA Litigation

Liberty Utilities (Granite State Electric) Corp.
5054 Monthly Disconnection and Account Receivables Report
For Month Ending December 31, 2022
Residential Accounts

	January	February	March	April	May	June	July	August	September	October	November	December	YTD
Number Of Business Days	20	19	23	21	22	22	20	23	21	-	20	21	232
Residential Disconnection Notices													
# of Disconnection Notices Mailed	1,132	952	1,077	1,080	1,199	1,297	1,070	362	1	-	-	-	8,170
$ Total balance owed on accounts with notice	$842,638	$743,684	$902,669	$879,942	$920,999	$973,740	$771,891	$309,653	$2,287	$0	$0	$0	6,347,504
$ Arrears balance owed on accounts with notice	$650,446	$583,292	$707,760	$716,294	$753,626	$786,902	$602,158	$211,691	$2,287	$0	$0	$0	5,014,457
Residential Terminations													
# of Accounts Terminated for Non Payment	3	-	1	108	82	60	83	65	-	-	-	-	402
$ Total balance owed on accounts terminated	$1,422	$0	$370	$99,662	$67,926	$52,754	$63,950	$68,882	$0	$0	$0	$0	354,965
$ Arrears balance owed on accounts terminated	$894	$0	$370	$82,685	$54,873	$43,701	$47,390	$52,673	$0	$0	$0	$0	282,586
# of Accounts Restored	2	-	-	80	67	44	66	52	-	-	-	-	311
# Restored same day	2	-	-	49	46	30	41	27	-	-	-	-	195
# Restored next day or after	0	-	-	31	21	14	25	25	-	-	-	-	116

NH PUC - Utility Accounts Receivable Report
Granite State

Residential Accounts	January	February	March	April	May	June	July	August	September	October	November	December	YTD
$ Sales Revenue	$5,833,238	$6,075,158	$5,989,636	$5,384,920	$4,729,168	$5,086,259	$6,250,992	$8,600,329	$7,120,279	$7,510,030	$6,483,955	$7,508,731	$76,572,695
# kwh	28,327,694	28,065,086	25,556,654	22,626,289	19,560,914	21,313,936	26,960,992	30,462,507	20,969,745	23,005,275	18,449,116	$21,671,821	$286,970,029
# of Customers	35,290	35,324	35,508	35,230	35,506	35,309	35,430	35,182	31,035	34,815	33,962	33,293	$415,884
$ Avg Customer Bill	$165	$172	$169	$153	$133	$144	$176	$244	$229	$216	$191	$226	$184
# Avg use (kwh)	803	795	720	642	551	604	761	866	676	661	543	651	690
***Gross Write-offs**	$29,685	$44,377	$35,457	$18,962	$37,479	$45,227	$15,647	$54,318	$3,076	$0	$0.00	$0.00	$211,187
*Recoveries	($1,093)	($3,027)	($2,615)	($3,562)	($4,137)	($2,298)	($3,181)	($3,922)	($1,605)	$0	(4,830)	(1,199)	($16,732)
*Net Write-off	$28,592	$41,350	$32,842	$15,400	$33,342	$42,930	$12,465	$50,397	$1,471	$0	(4,830)	($1,199)	$194,455
** Combined Residential and Commercial Data*													
$ Late Charge Revenue	$9,591	$4,457	$8,500	$8,062	$5,981	$7,108	$7,838	$4,923	$8,125	$208	$4,899	$10,854	$43,699
Accounts Receivable													
$ Current	$5,353,914	$5,847,409	$5,292,579	$5,110,373	$4,535,022	$4,667,612	$5,836,971	$7,479,230	$6,872,305	$8,659,727	$7,617,844	$8,207,043	$75,480,028
$ 30 days past due	$396,629	$459,405	$513,418	$587,538	$604,308	$506,174	$437,541	$421,835	$594,784	$788,714	$765,442	$887,039	$6,962,827
$ 60 days past due	$244,476	$261,864	$273,157	$326,413	$397,589	$364,085	$330,608	$258,905	$299,196	$200,867	$557,042	$708,255	$4,222,458
$ 90 days past due	$191,888	$158,438	$144,757	$159,038	$186,565	$229,924	$204,838	$166,730	$190,599	$162,300	$186,407	$415,626	$2,397,110
$ Over 90 days past due	$923,951	$945,921	$916,968	$890,666	$867,157	$869,392	$934,934	$931,436	$978,204	$791,526	$1,748,889	$1,886,056	$12,685,100
Total A/R	$7,110,856	$7,673,036	$7,140,879	$7,074,028	$6,590,641	$6,637,188	$7,744,891	$9,258,136	$8,935,088	$10,603,134	$10,875,624	$12,104,020	$101,747,523

Prepared by: Shelby Ivey
Date: 1/26/2023
Reviewed by: Audrey Sobolesky
Date: 1/26/2023

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 6

Date Request Received: 8/31/23 | Date of Response: 9/15/23
Request No. DOE 6-4 | Respondent: Gregg Therrien

REQUEST:

Reference Testimony of Gregg Therrien at Bates II- 827 stating that “base rates were designed to recover $61,377,409 of delivery-related revenue requirements” and that “this amount is the sum of the $45,890,407 test year normalized revenues calculated in Attachment GHT-2 plus the revenue deficiency of $15,487,002 discussed in the testimony of the Revenue Requirements panel.”

Reference also Testimony of Gregg Therrien at Bates II – 826 where Mr. Therrien states that “normal distribution revenues have been calculated using the most recently approved base distribution rates effective March 1, 2023. These rates are then multiplied times actual calendar 2022 (test year) billing determinants.”

Reference also the statement from Department of Energy Attorney Dexter on 5/30/23 in PUC Docket No. DE 22-035 (transcript at p. 61):

“I think the Company is going to have to make a positive revenue adjustment to their test year revenues, to reflect the fact that they had the wrong rates in effect for the five months of the test year. I don't think it's going to be complicated.”

Reference also Liberty Attorney Sheehan stated (5/30/23 transcript at 65):

“[O]n the rate case, I do see this as a simple issue. It makes perfect sense that what we've heard today does indicate our revenue in 2022, if we just look at what was in place was lower than it should have been, and it may very well have understated what's in the rate case, which would overstate our revenue request. And there's two easy fixes. One, they may have fixed it in calculating the rate case. I don't know either. We do many adjustments to test year revenues to fix issues like that was done, but that's an easy check. If not, yes, we will make the adjustment to the test year revenues. So, I agree with Mr. Dexter that the fix is easy to identify and easy to do, as necessary.”

a. Please provide corrected test year normalized revenues to address Liberty's billing incorrect rates for 5 months in the test year as discussed above and quantify the impact on test year normalized revenues of using the correct rates instead.

b. Please quantify the impact of this change on the Company's requested revenue deficiency and revenue requirements for each of proposed Rates Years 1, 2, and 3.

RESPONSE:

a. Please see Attachment 23-039 DOE 6-4.a. Total corrected test year revenues, now based on August 1, 2023, rates currently in effect (excluding the July 1, 2023, temporary rate adjustment), equal $48,019,557 (Line 19 of attachment).

b. Revised revenues are $2,129,170 higher than that included in the Company's Application (Line 19 of attachment).

Liberty Utilities (Granite State Electric) Corp.
Summary of Revenues at Present Rates
Response to DOE 6-4

Granite State Electric
2022 Test Year

REVISED PER DOE 6-4 9/15/2023

Line	**Distribution Operating Revenue**	FERC Account	Unadjusted Test Period	Test Period Adjustments	Adjusted Test Period	Adjustment Explanation
1	Distribution (calculated)[1]					
2	Residential	440	$24,677,791	$2,245,454	$26,923,245	Rate normalization to 08/2023 rates (inclusive of temporary rate increase). Minor corrections to D-5, D-11 CPP and LED-2 kWh.
3	Commercial	442	$22,558,771	$2,847,327	$25,406,098	
4	Industrial	444	$1,004,313	$148,797	$1,153,110	
5	Subtotal Distribution		$48,240,875	$5,241,578	$53,482,453	
6	Prov. For Refunds	449	($1,018,212)	$1,018,212	$0	Assume no over/(under) "T" collection
7	Misc. service revenue	451	$536,454	($14,690)	$521,764	Change in NSF, Connect/Reconnect occurrences and fees
8	Rent from Electric property	454	$361,375		$361,375	No Adjustment
9	Revenue Decoupling	456	$2,408,283	($2,408,283)	$0	Assumes new rates recover full rev req
10	Other revenue	456	($725,948)	$239,618	($486,331)	Removal of Step Adjustment
11	Sales for resale	447	$169,677	($169,677)	$0	Revised adjustment to reflect fact that these revenues are included in distribution revenues above.
12	**Total**		**$49,972,503**	**$3,906,758**	**$53,879,261**	
13	Less: Temporary rate increase included in August 1, 2023 rates				($5,462,876)	
14	Normalized Test Year Revenues				**$48,416,385**	

TY Normalized Revenues

Line		Change to GHT-2		Distribution Only	
15	Revised per DOE 6-4	$53,482,453	Revised per DOE 6-4	$53,482,453	Line 5
16	Attachment GHT-2 as filed	$45,890,407			
17	Increase/(Decrease)	$7,592,046			
18	Less: July 2023 temporary rate increase	($5,462,876)		($5,462,876)	Line 13
19	Total Change	$2,129,170	Normalized TY Revenues	$48,019,577	

[1] "Unadjusted Test Period" distribution revenues calculated using the then-current rates in effect times normalized billing determinants provided by the company. "Adjusted Test Period" distribution revenues use August 1, 2023 rates for all months.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Data Requests - Set 9

Date Request Received: 9/22/23 | Date of Response: 10/6/23
Request No: DOE 9-15 | Respondent: Gregg Therrien

REQUEST:

Reference DOE 6-004, regarding corrected test year revenues, and the September 11, 2023 filing by the Company in DE 22-035, which corrects errors in the rates in the August 1, 2023 filing used as the basis for the response in DOE 6-004. Please update the following response provided in DOE 6-004 with the correct information:

a. Please provide corrected test year normalized revenues to address Liberty's billingincorrect rates for 5 months in the test year as discussed above and quantify the impact on test year normalized revenues of using the correct rates instead.
b. Please quantify the impact of this change on the Company's requested revenue deficiency and revenue requirements for each of proposed Rates Years 1, 2, and 3.

RESPONSE:

a. Please see Attachment 23-039 DOE 9-15. Total test year revenues, based on the proposed November 1 rates included in the Company's September 11, 2023, filing (excluding the July 1, 2023, temporary rate adjustment), equal $48,023,470 (Line 19 of the attachment).
b. Revised revenues are $2,133,063 higher than that included in the Company's Application (Line 19 of the attachment).

Liberty Utilities (Granite State Electric) Corp.
Summary of Revenues at Present Rates
Response to DOE 9-15

Docket No. DE 23-039
Attachment 23-039 DOE 9-15

Granite State Electric
2022 Test Year

REVISED Per DOE 9-15 9/29/2023

Line	Distribution Operating Revenue	FERC Account	Unadjusted Test Period	Test Period Adjustments	Adjusted Test Period	Adjustment Explanation
1	Distribution (calculated)[1]					
2	Residential	440	$24,677,791	$2,248,416	$26,926,207	Rate normalization to 08/2023 rates (inclusive of temporary rate increase). Minor corrections to D-5, D-11 CPP and LED-2 kWh.
3	Commercial	442	$22,558,771	$2,848,231	$25,407,002	
4	Industrial	444	$1,004,313	$148,823	$1,153,137	
5	Subtotal Distribution		$48,240,875	$5,245,471	$53,486,346	
6	Prov. For Refunds	449	($1,018,212)	$1,018,212	$0	Assume no over/(under) "T" collection
7	Misc. service revenue	451	$536,454	($14,690)	$521,764	Change in NSF, Connect/Reconnect occurrences and fees
8	Rent from Electric property	454	$361,375		$361,375	No Adjustment
9	Revenue Decoupling	456	$2,408,283	($2,408,283)	$0	Assumes new rates recover full rev req
10	Other revenue	456	($725,948)	$239,618	($486,331)	Removal of Step Adjustment
	Sales for resale	447				Revised adjustment to reflect fact that these revenues are included in distribution revenues above.
11			$169,677	($169,677)	$0	
12	**Total**		**$49,972,503**	**$3,910,651**	**$53,883,154**	
13	Less: Temporary rate increase included in August 1, 2023 rates				($5,462,876)	
14	Normalized Test Year Revenues				**$48,420,278**	

TY Normalized Revenues

Line		Change to GHT-2		Distribution Only	
15	Revised per DOE 9-15	$53,486,346	Revised per DOE 9-15	$53,486,346	Line 5
16	Attachment GHT-2 as filed	$45,890,407			
17	Increase/(Decrease)	$7,595,939			
18	Less: July 2023 temporary rate increase	($5,462,876)		($5,462,876)	Line 13
19	Total Change	$2,133,063	Normalized TY Revenues	$48,023,470	

[1] "Unadjusted Test Period" distribution revenues calculated using the then-current rates in effect times normalized billing determinants provided by the company. "Adjusted Test Period" distribution revenues use proposed November 1, 2023 rates for all months.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039

Distribution Service Rate Case

NH Department of Energy Data Requests - Set 6

Date Request Received: 8/31/23 | Date of Response: 9/15/23
Request No. DOE 6-23 | Respondent: Heather Green

REQUEST:

Reference Attachment DOE 3-5: VMP Project Rate Years Spending.

a. Provide a detailed breakdown of the cost components that comprise the Planned Cycle Trimming line item. Specifically, breakout the cost associated with increasing the size of the trimming box.
b. Describe the role and responsibilities of the work planners, number of individuals, who they work for, and who they report to.
c. Explain why the work planners' cost was increased under the "2023 Budget (Full Services)" (column D).
d. Provide a typical field plan and report a work planner provides to Liberty as part of their responsibility.

RESPONSE:

In preparing this response, the Company identified that the May 5, 2023, filing contained an erroneous schedule and definitions on Bates pages II-572 through II-575. In the Company's response to DOE 1-1, specifically Attachment DOE 1-1.5.xlsx, the Company provided an attachment revising the schedule on Bates II-572, however did not clearly identify that the Company provided a revised schedule. The original schedule as filed on Bates II-572 was missing a line for Program Assessment of $66,384 in 2025 ($33,192 in Rate Year 1 and $33,192 in Rate Year 2) and contained outdated program names and definitions.

In the Company's response to DOE 3-5, the Company provided an attachment in the response that referred to the original schedule as filed on Bates II-572.

With this response, the Company is providing Attachment 23-039 DOE 6-23.1 containing the revised Rate Years 2 and 3 VMP plan to reflect the Program Assessment line and as provided in Attachment DOE 1-1.5 as well as a revised program definitions updating what was originally filed on Bates II-573 through II-575.

a. The Cycle Trim (Planned Cycle Trimming) line item per Attachment 23-039 DOE 6-23.1.xlsx, line 18, is comprised of only one (1) item. It reflects the estimated tree contractor lump sum bid cost to perform routine tree trimming on the designated mileage as listed in line 11 (# Miles). These costs were estimated based on historical cost per mile with a 10 percent adder per year. The Company acknowledges that fluctuations in the supply chain and the labor market make it very difficult to estimate future costs and has proposed a full annual reconciliation of these costs.

   A specific breakdown of the cost associated with increasing the size of the trimming box does not exist.

b. The plan includes three arborists or work planners. Two of the work planners are responsible for pre-planning the work at a property and span level to provide an executable work plan to the tree crews. Responsibilities also include property owner notification and permissions for tree trims/removals where required and auditing the completion of the tree work to ensure contract compliance.

   One work planner is responsible for process implementation and improvements, data integrity, Terra Spectrum Field Note build and support, support of invoice processing, quality control, assisting in auditing, training, work coordination, and more.

   In addition to the duties described above, the work planners support the vegetation management program in any way needed, depending on the needs of the program. These duties include investigation of tree-related interruptions (to provide guidance on future tree removal priorities), customer service needs, verifying safe tree crew practices, risk tree evaluation, data entry, data validation, coordination of joint work between the vegetation department and other entities, scenic road work requests and town hearings, assistance to tree crews with data entry, and data entry software training.

   The three work planners are contracted, external resources that report to the Manager of Vegetation Management for Liberty.

c. The "Full Services" in column (e) in Attachment 23-039 DOE 6-23.1.xlsx refers to the cost to fully fund the program per the Company's estimate. Column (d) refers to how the company budgeted programs and resources to achieve the $2.4 M agreed-upon budget. The increase from the budget established in the previous rate case now reflects the Company's estimate to provide full services.

d. The work planners identify the work that needs to be performed and write the work order for the crews to execute the work. There are no specific "Work Planners reports," there are only work orders that the work planners write up according to their review of the work needed to be done.

   See Attachment 23-039 DOE 6-23.2 for a demonstration of the type of instructions/advice provided by the work planners to Liberty and the vegetation management crews as previously provided in response to DOE TS 1-2 in Docket No. DE 21-138.

Attachment 11

Revision to Bates II-575, Attachment HG-4

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
1																									
2																									
3																									
4																									
5																									
6																									
7																									
8						Bridge Period		Rate Year 1				Rate Year 2				Rate Year 3									
9					Escalator	**Q1 2023**	**Q2 2023**	**Q3 2023**	**Q4 2023**	**Q1 2024**	**Q2 2024**	**Q3 2024**	**Q4 2024**	**Q1 2025**	**Q2 2025**	**Q3 2025**	**Q4 2025**	**Q1 2026**	**Q2 2026**	**Q3 2026**	**Q4 2026**	**Q1 2027**	**Q2 2027**	**Q3 2027**	**Q4 2027**
10	Vegetation Management	Vegetation Management (VM)		5 Yr																					
11	# Miles	# Miles	165.09	175.00		41.27	41.27	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75						
12	Type of Work Attachment 23-039 DOE 3-5	Type of Work Attachment 23-039 DOE 1-1.5	2023 Budget ($2.4M)	2023 Budget (Full Services)	Annual Escalator	2023 Q1 Budget	2023 Q2 Budget	2023 Q3 Budget	2023 Q4 Budget	2024 Q1 Budget	2024 Q2 Budget	2024 Q3 Budget	2024 Q4 Budget	2025 Q1 Budget	2025 Q2 Budget	2025 Q3 Budget	2025 Q4 Budget	2026 Q1 Budget	2026 Q2 Budget	2026 Q3 Budget	2026 Q4 Budget				
13																									
14	Work Planners for Veg Plan	Cycle Administration	$220,000	$375,000	5%	$55,000	$55,000	$93,750	$93,750	$98,438	$98,438	$98,438	$98,438	$103,359	$103,359	$103,359	$103,359	$108,527	$108,527	$108,527	$108,527				
15	Spot Tree Trimming	Spot Work	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
16	Trouble and Restoration Maintenance	Trouble and Restoration Maintenance	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
17	Interim Trimming	Interim Trimming	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
18	Planned Cycle Trimming	Cycle Trim	$1,435,663	$1,418,025	10%	$358,916	$358,916	$354,506	$354,506	$389,957	$389,957	$389,957	$389,957	$428,953	$428,953	$428,953	$428,953	$471,848	$471,848	$471,848	$471,848				
19	Police Detail Expenses - Cycle Trimming & Other	Traffic Control	$324,836	$607,099	5%	$81,209	$81,209	$151,775	$151,775	$159,363	$159,363	$159,363	$159,363	$167,332	$167,332	$167,332	$167,332	$175,698	$175,698	$175,698	$175,698				
20	Hazard Tree Removal	Fall-In Risk Tree Removals	$50,000	$437,500	5%	$12,500	$12,500	$109,375	$109,375	$114,844	$114,844	$114,844	$114,844	$120,586	$120,586	$120,586	$120,586	$126,615	$126,615	$126,615	$126,615				
21	Hazard Tree Removal - Catch up	Grow-In Risk Tree Removals	$0	$437,500	5%	$0	$0	$109,375	$109,375	$114,844	$114,844	$114,844	$114,844	$120,586	$120,586	$120,586	$120,586	$126,615	$126,615	$126,615	$126,615				
22	Brush & Limb Lead Removal	Brush & Limb Lead Removal	$0	$135,200	5%	$0	$0	$33,800	$33,800	$35,490	$35,490	$35,490	$35,490	$37,265	$37,265	$37,265	$37,265	$39,128	$39,128	$39,128	$39,128				
23	Tree Planting	Tree Planting	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
24	IVM/ Herbicide in ROW	ROW IVM Sub-Transmission Herbicide	$69,210	$69,210	Specific	$17,303	$17,303	$17,303	$17,303	$15,000	$15,000	$15,000	$15,000	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250				
25	Polinator Education/Habitat	ROW IVM Pollinator Education/Habitat	$5,000	$5,000	5%	$1,250	$1,250	$1,250	$1,250	$1,313	$1,313	$1,313	$1,313	$1,378	$1,378	$1,378	$1,378	$1,447	$1,447	$1,447	$1,447				
26	Monarch Butterfly Conservation	ROW IVM Monarch Butterfly Conservation	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
27	AI- Dash Software	VM Software AI- Dash	$42,000	$42,000	5%	$10,500	$10,500	$10,500	$10,500	$11,025	$11,025	$11,025	$11,025	$11,576	$11,576	$11,576	$11,576	$12,155	$12,155	$12,155	$12,155				
28	Mailers/ Permissions	Printed Material	$3,500	$5,000	5%	$875	$875	$1,250	$1,250	$1,313	$1,313	$1,313	$1,313	$1,378	$1,378	$1,378	$1,378	$1,447	$1,447	$1,447	$1,447				
29	Permit Fees	Permit Fees	$25,000	$25,000	5%	$6,250	$6,250	$6,250	$6,250	$6,563	$6,563	$6,563	$6,563	$6,891	$6,891	$6,891	$6,891	$7,235	$7,235	$7,235	$7,235				
30	Terra Spectrum	VM Software Terra Spectrum	$25,000	$25,000	5%	$6,250	$6,250	$6,250	$6,250	$6,563	$6,563	$6,563	$6,563	$6,891	$6,891	$6,891	$6,891	$7,235	$7,235	$7,235	$7,235				
31	Training	Training	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
32	Sub-Transmission Right of Way Clearing	ROW IVM Sub-Transmission Clearing	$0	$80,000	5%	$0	$0	$20,000	$20,000	$21,000	$21,000	$21,000	$21,000	$22,050	$22,050	$22,050	$22,050	$23,153	$23,153	$23,153	$23,153				
33	Make Safe Removals	Make Safe Work	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
34		Program Assessment	$0	$0	5%	$0	$0	$0	$0	$0	$0	$0	$0	$16,596	$16,596	$16,596	$16,596	$0	$0	$0	$0				
35	Total VMP O&M Expenses	Total VMP O&M Expenses	$2,419,709	$3,923,363		$604,927	$604,927	$980,841	$980,841	$1,044,441	$1,044,441	$1,044,441	$1,044,441	$1,118,256	$1,118,256	$1,118,256	$1,118,256	$1,178,129	$1,178,129	$1,178,129	$1,178,129				
36																									
37	Calendar Year	Calendar Year						CY23	$3,171,536			CY24	$4,177,762			CY25	$4,473,026			CY26	$4,712,514				
38								RY1	$4,050,563			RY2	$4,325,394			RY3	$4,592,770								
39		Bridge period spending = 50% of allowed rates ($2.2M) + 10% overage = $1.21M																							
40		Assumes a reset of trim cycles - no catch up of deferred miles																							
41		Assumes a 5 year trim cycle consistent with Puc 307.10																							
42		Assumes full reconciliation of vegetation management costs through the Revenue Adjusment Charge (RAC) - actuals compared to forecasted rate year																							

Brush & Limb Lead Removal (Planned)
This captures all charges for removal of 4.5”-8.5” diameter* trees or limb leads 8.5” diameter or greater on the system typically performed with cycle work. However, may be performed off cycle as catchup.
DNH.VEGMGNT.VM.1220.5931

Cycle Administration: (Planned)
This captures the activities around the work planning and administrative processes. Work planning is a systematic approach to prescribing vegetation maintenance work around power lines. It involves the patrol and inspection of the power line corridor on a span-by-span basis. Work planning begins with an experienced (and typically degreed) forester working as an inspector (work planner). The clearances and tree selection parameters are pre-determined by the utility and are applied to the field conditions. Work is recorded in a software management system and assigned. The prescribed work is executed by the line clearance contractor. The work planning process concludes with a review of the work by auditing. Additional administrative responsibilities include, but are not limited to: process implementation and improvements, data integrity management, Terra Spectrum Field Note build and support, support of invoice processing, quality control, assisting in auditing,providing training, p[roviding work coordination and more.
DNH.VEGMGNT.VM.1000

Cycle Trim: (Planned)
This captures charges for annual fiscal year of obtaining permissions and execution of planned cycle pruning, brush cutting, clearing and vine removals activities but does not include police detail expenses, removals 5” in diameter or greater or work planning.
DNH.VEGMGNT.VM.1215

Enhanced Risk Tree Removal (ERTM): (Planned) (Not in current budget. Placeholder for future.)
Captures all charges for the hazard tree removal program directed at improving reliability of on and off cycle poor performing circuits based on removing dead, dying and/or structurally weak trees, limbs and leads on the three phase portions of those targeted circuits using a Customer Served approach beyond each major reliability device point including the lockout section or station breaker to the first reliability device.
DNH.VEGMGNT.VM.1220.5933

Fall-In Risk Tree Removals (Planned)
This captures all charges for removal of fall-in (mostly growing outside the corridor) risk related dead, dying and/or structurally weak trees, limbs and leads typically performed with cycle work. However, may be performed off cycle as catchup.
DNH.VEGMGNT.VM.1220.5933

Grow-In Risk Tree Removals (Planned)
This captures all charges for tree removals growing within the corridor typically performed with cycle work. However, may be performed off cycle as catchup. Typically, the diameter is 8.6” in diameter or greater. Removal of these trees helps establish the corridor to maintain in the future.
DNH.VEGMGNT.VM.1220.5932

Integrated Vegetation Management (IVM)
A system of managing plant communities in which compatible and incompatible vegetation are identified; action thresholds are determined; tolerance levels are established; and control methods are evaluated, selected and applied to achieve management goals and maintenance objectives. IVM often integrates multiple methods to promote sustainable plant communities that are compatible with management goals

Interim Trimming: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for charges for mitigation of tree conditions that threaten reliability of one or more sections of primary conductor on a circuit or circuits not contained in the current fiscal year's annual plan of work.
DNH.VEGMGNT.VM.1235

Make Safe Work: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for assistance to private tree work as required to allow a landowner to perform property maintenance while following industry safety requirements.
DNH.VEGMGNT.VM.1010.5932

Permit Fees
This captures all charges for activities related to permitting, ie environmental permits, railroad permits, scenic roads, etc.
DNH.VEGMGNT.VM.1215.5932

Printed Material
This captures all charges for activities related to printed material to perform program needs: mailers, door hangers, tree removal forms, traffic control forms, etc.
DNH.VEGMGNT.VM.1215.5932

Program Assessment
A review and assessment of the vegetation maintenance program evaluating efficiency and effectiveness. Performed by a 3rd party contractor.
DNH.VEGMGNT.VM.1215.5932

VM Software
Vegetation Management software includes Ai-Dash and Terra Spectrum and others as needed. Ai-Dash and Terra Spectrum are 2 software tools utilized as work management system, evaluation tool, and reporting or projecting experiences or expectations.
DNH.VEGMGNT.VM.1215.5932

ROW IVM: Monarch Butterfly Conservation
This captures all charges for activities related to Monarch Butterfly Conservation to aid in effective and efficient IVM.
DNH.VEGMGNT.VM.1280

ROW IVM: Pollinator Education/Habitat
This captures all charges for activities related to incorporating promotion of pollinator habitat and cultural activities to aid in effective and efficient IVM.
DNH.VEGMGNT.VM.1280

ROW IVM: Sub-Transmission Clearing (Floor & Side & Removals):
This captures all charges for activities related to cutting, clearing, herbicide application and tree removal on off-road distribution and substation supply lines up to 115kV.
DNH.VEGMGNT.VM.1280

ROW IVM: Sub-Transmission Herbicide
This captures all charges for activities related to herbicide application on off-road distribution and substation supply lines up to 115kV.
DNH.VEGMGNT.VM.1280.5934

Spot Work: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up of corrective action required, if any, to mitigate vegetation management concerns requested or reported by a customer between cycle work. Can usually be scheduled over next several weeks to months for efficiencies.
DNH.VEGMGNT.VM.1010.5931

Traffic Control: (Planned & Unplanned)
This captures all charges for traffic control expenses associated with annual planned cycle trim, tree removals, and unplanned work of spot trimming, trouble, interim work and other Vegetation Management work requiring traffic control.
DNH.VEGMGNT.VM.1218

Training
Scope of work, safety, software, process, or more training for program supervisors, administrators or crews as needed. Can be one on one or in group settings.
DNH.VEGMGNT.VM.1215.5932

Tree Planting:
This captures all charges for tree replacements in exchange for tree removals of full clearance, tree replacement to remediate property owner complaints, trees planted for Arbor Day events.
DNH.VEGMGNT.VM.1240

Trouble and Restoration Maintenance: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for response and corrective action to mitigate isolated tree related trouble, overhead line requests to mitigate tree related trouble and storm responses not covered by a storm specific charge number. It typically requires immediate response. That is, cannot be schedule weeks or months later.
DNH.VEGMGNT.VM.1210

VM
Vegetation Management

*Diameter of trees is measured 4.5’ from the ground.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 21-138
Calendar Year 2022 Vegetation Management Program (VMP) Plan

Department of Energy Tech Session Data Requests –Set 1

Date Request Received: 4/14/22	Date of Response: 4/19/22
Request No. DOE TS 1-2	Respondent: Heather Green

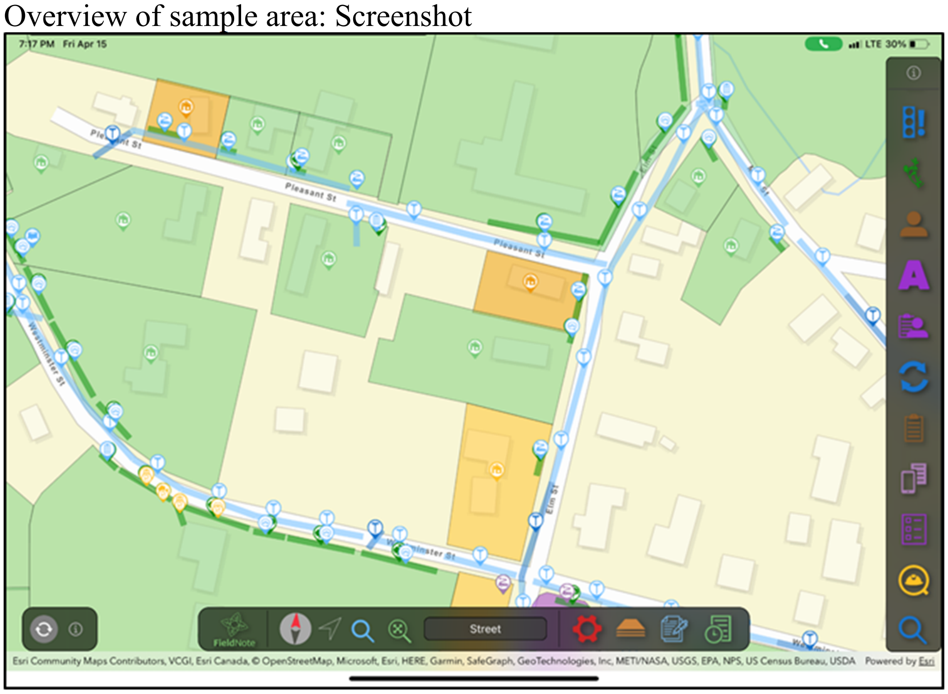
REQUEST:

Refer to response DOE 1-2 which describes the duties of work planner/arborist and states that the work planners do not produce specific reports. At the tech session, Liberty stated that the instructions from the work planners are conveyed to Liberty and the vegetation management crews via computer tablets on a real- time basis. Please provide a sample of screen shots from these computer tablets which demonstrate the type of instructions/advice provided by the work planners to Liberty and the vegetation management crews.

RESPONSE:

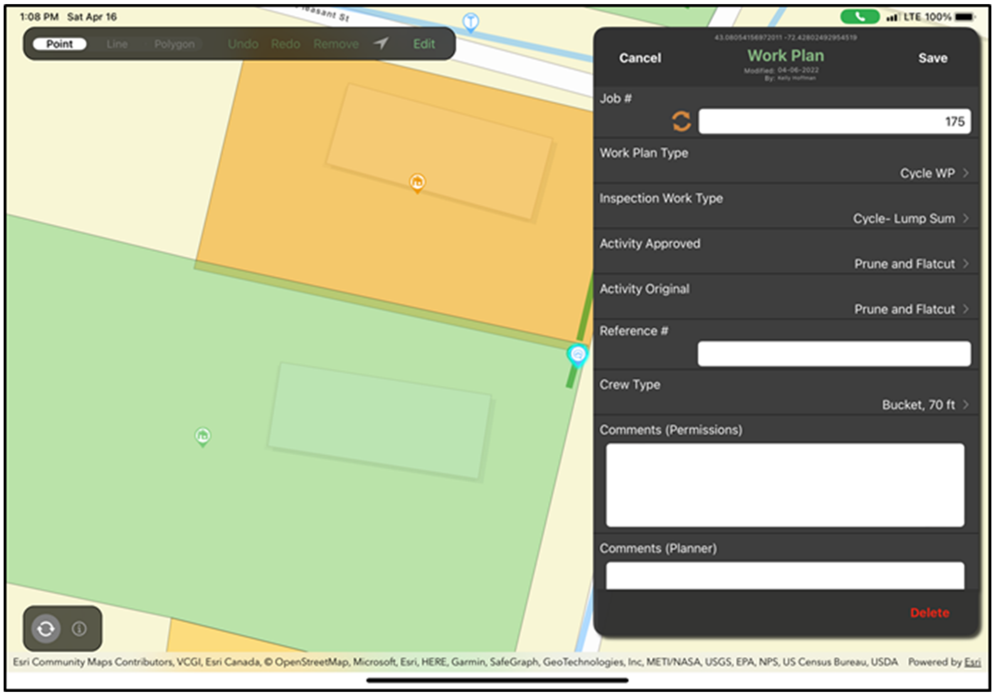
Please see the screenshots below demonstrating the type of information captured by the work planners.

Overview of sample area: Screenshot



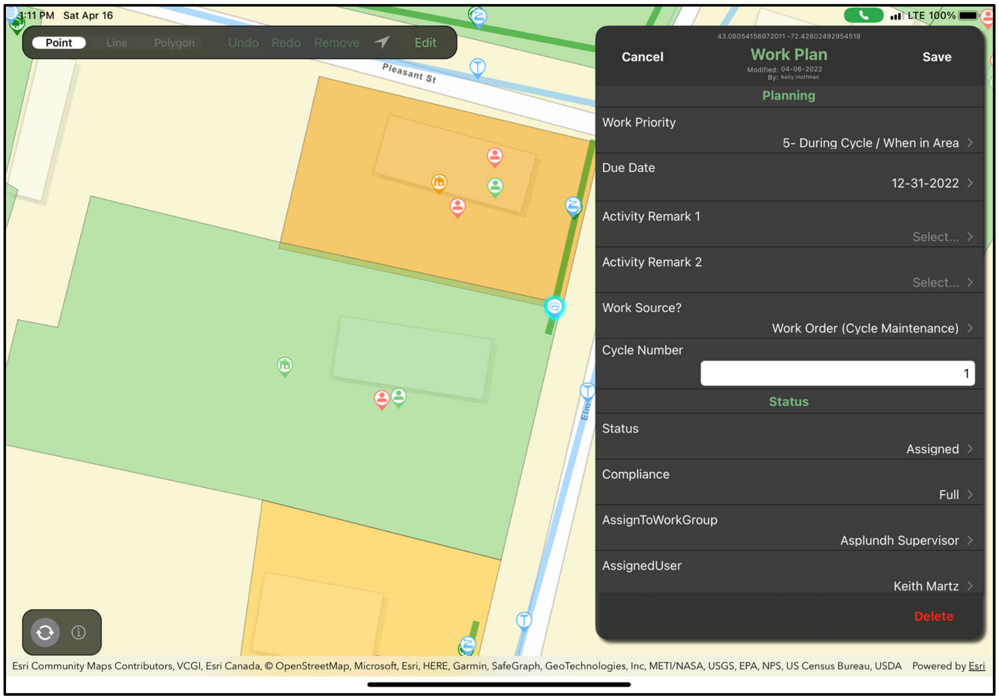
The following screenshots show the data collected in the various forms: Work Plan Form, Property Form, Vegetation Form, and Line Segment Form.

Work Plan: Screenshot 1



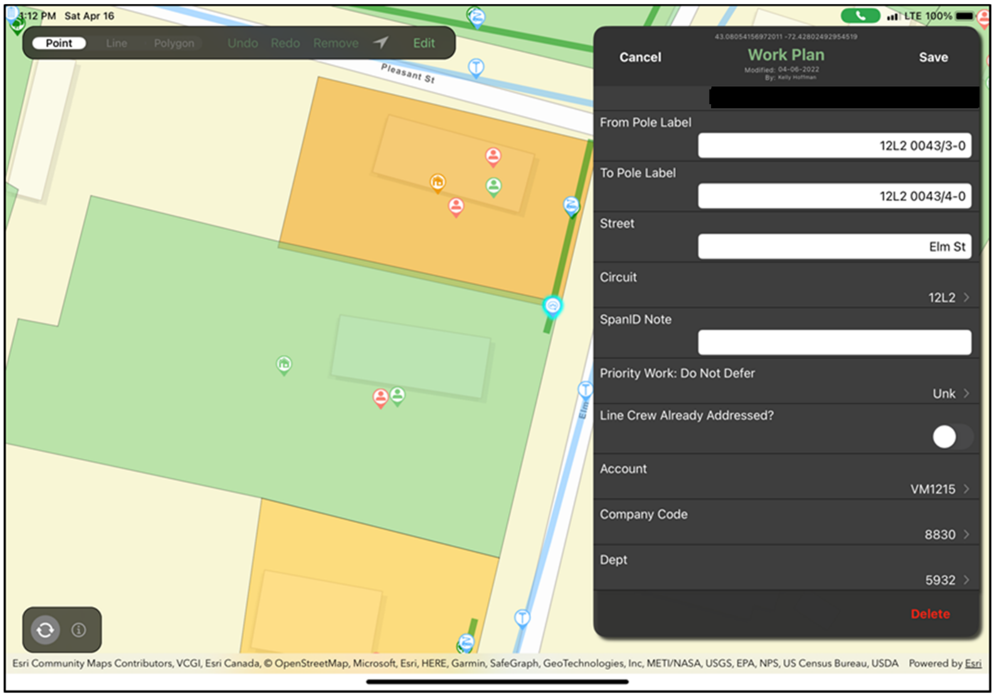
Work Plan: Screenshot 2

Work Plan: Screenshot 3

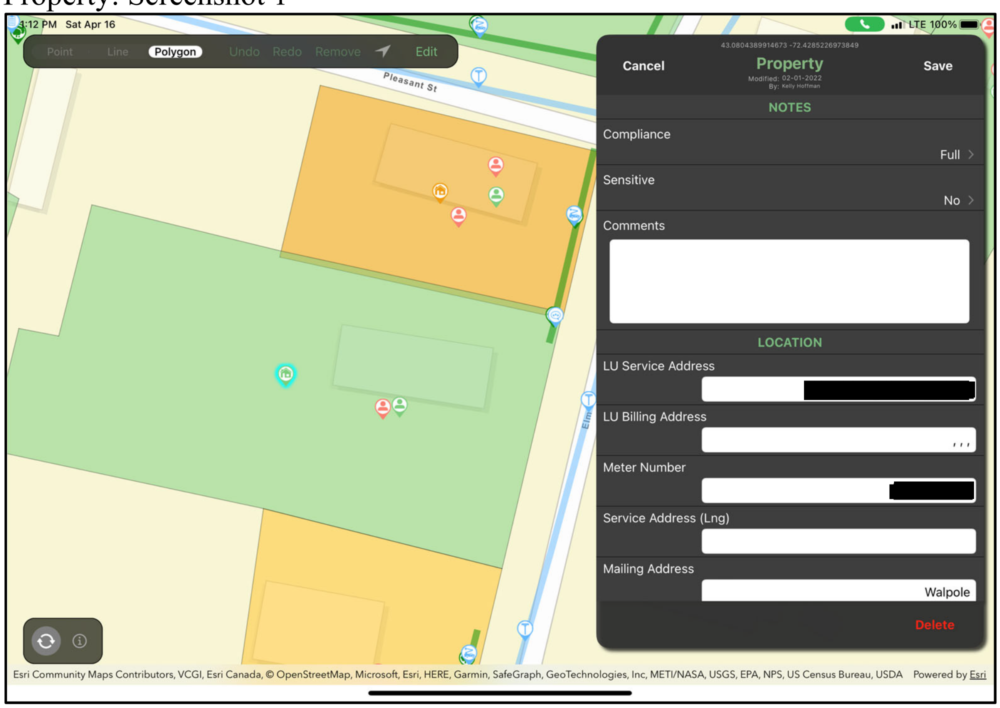


Work Plan: Screenshot 4

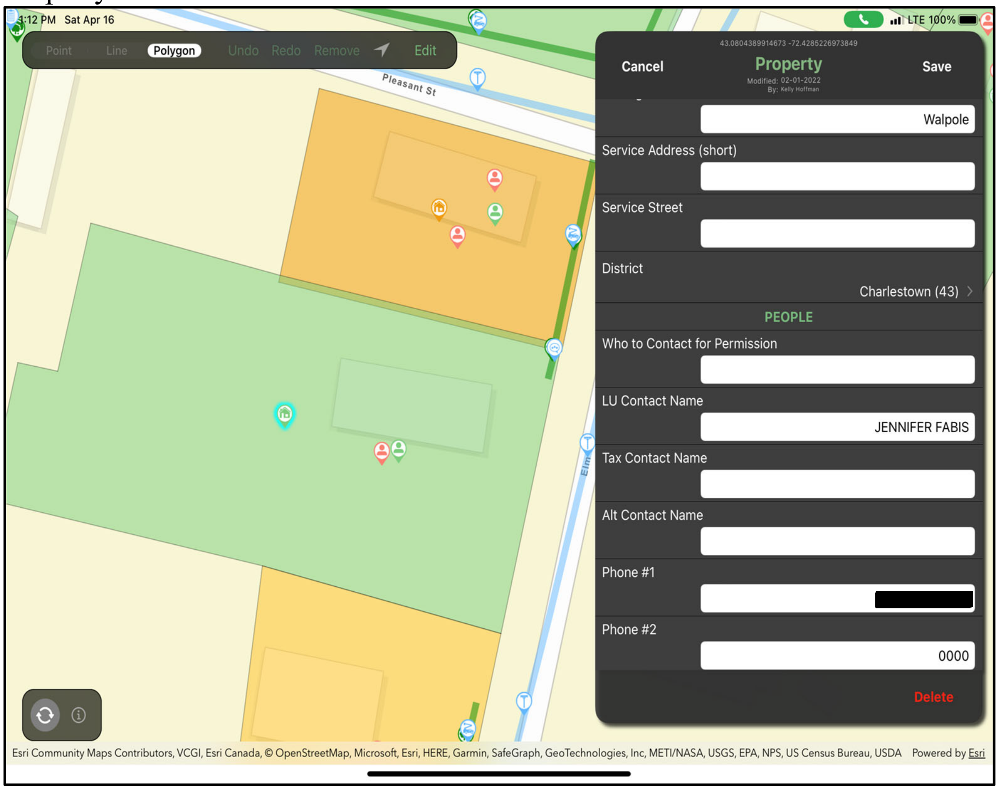
Work Plan: Screenshot 5



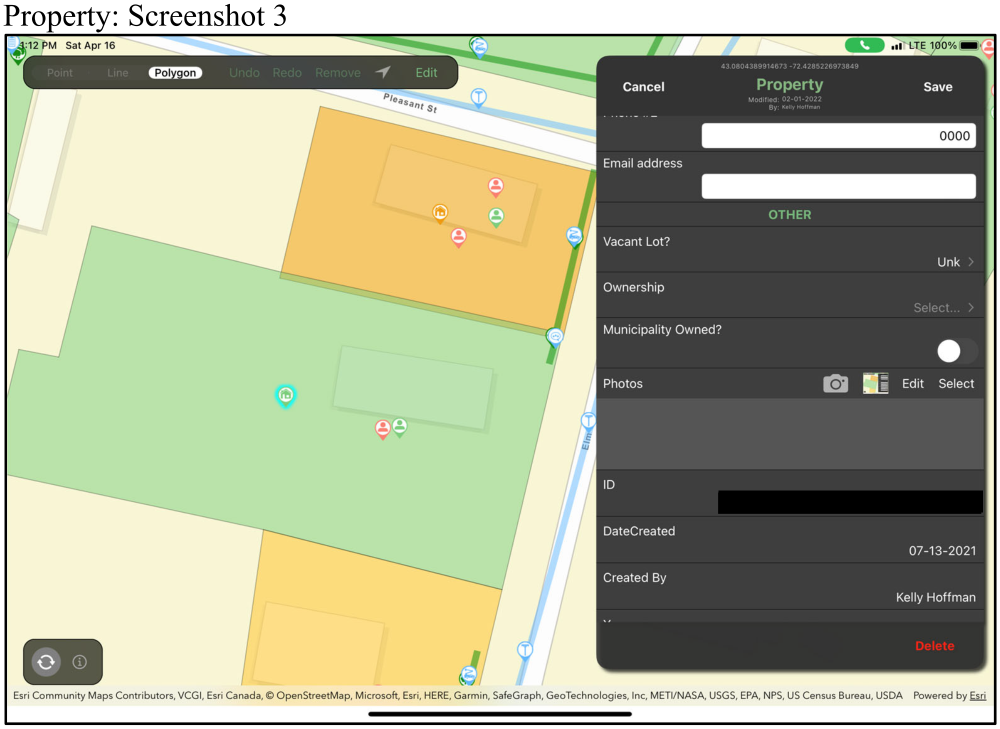
Property: Screenshot 1



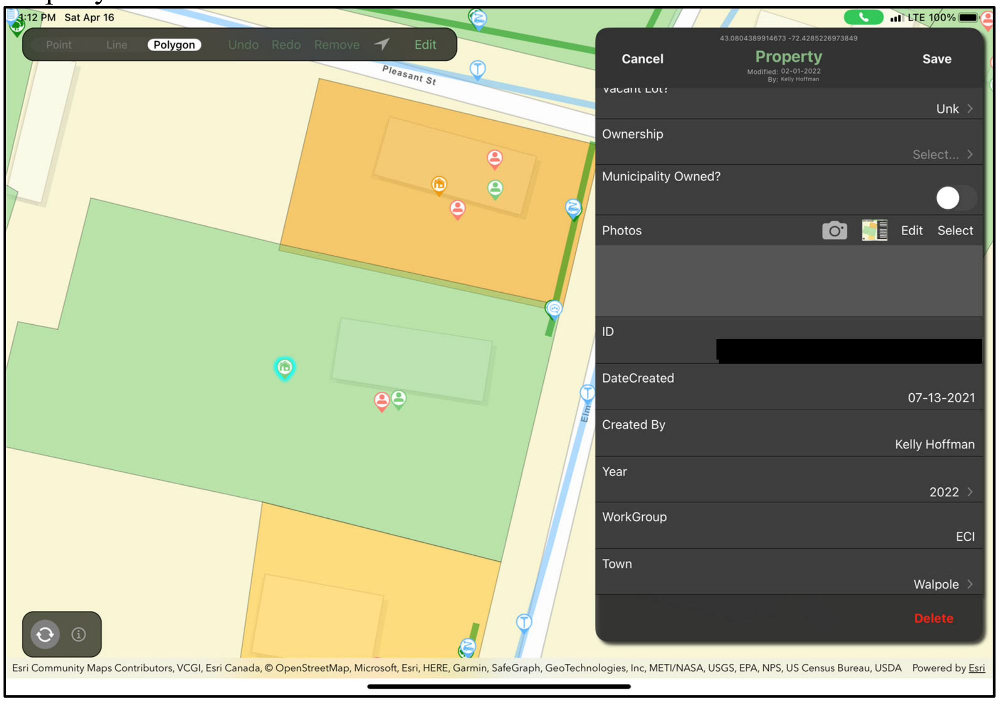
Property: Screenshot 2



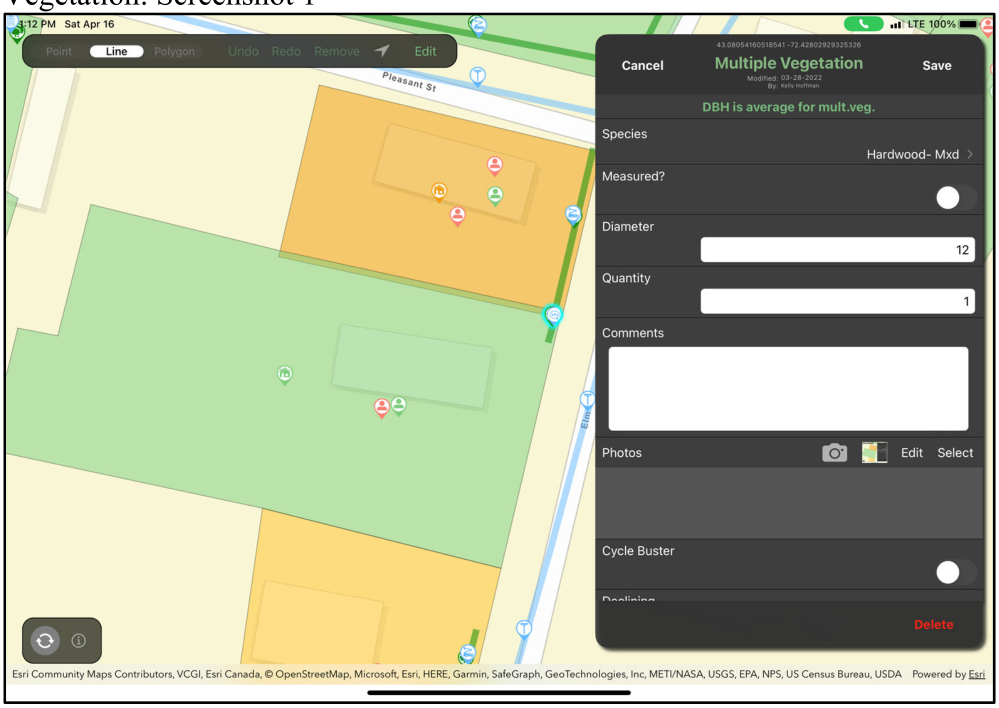
Property: Screenshot 3



Property: Screenshot 4

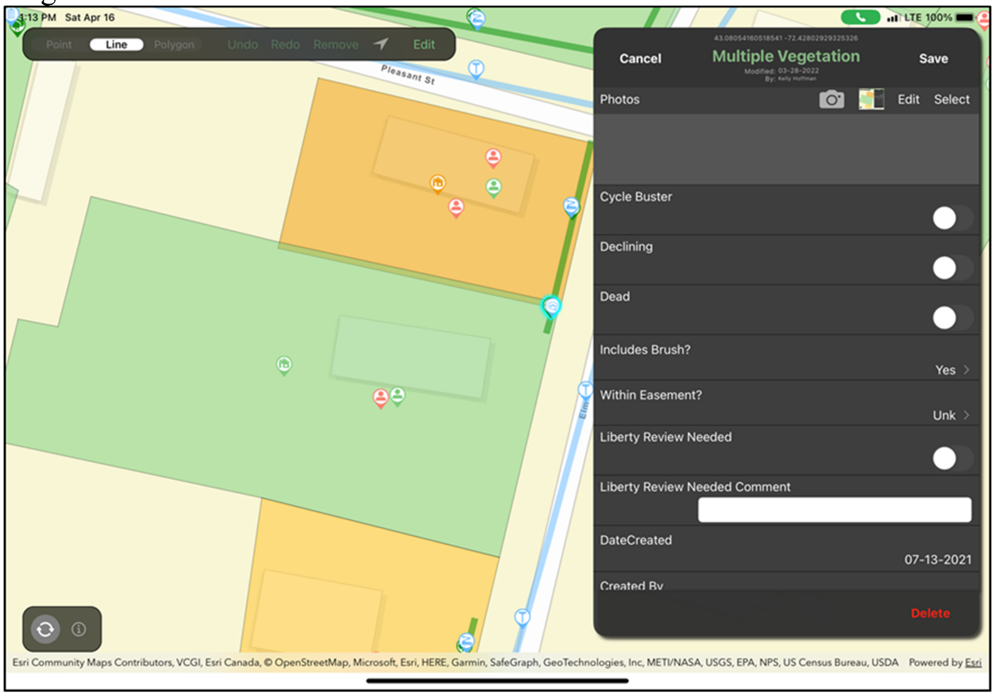


Vegetation: Screenshot 1

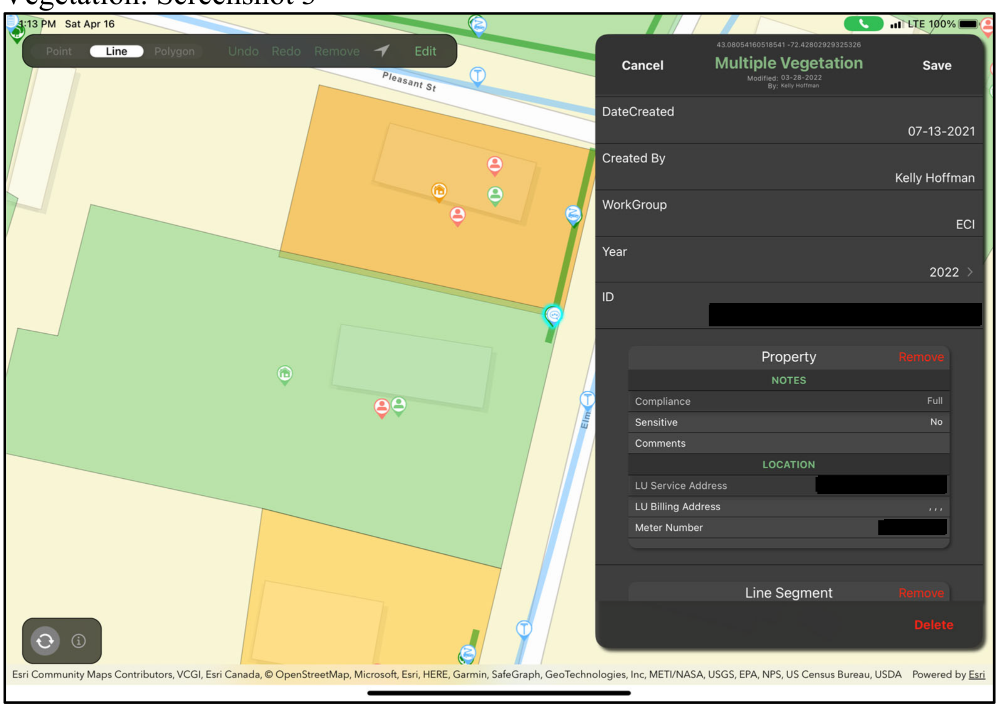


Docket No. DE 21-138 Request No. DOE TS 1-2

Vegetation: Screenshot 2

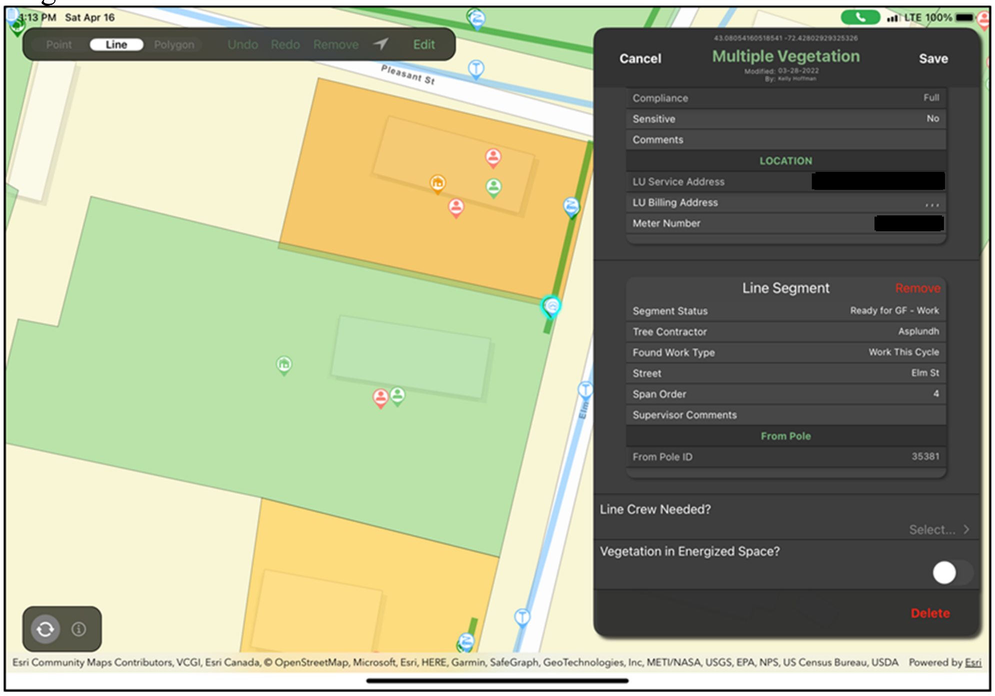


Vegetation: Screenshot 3

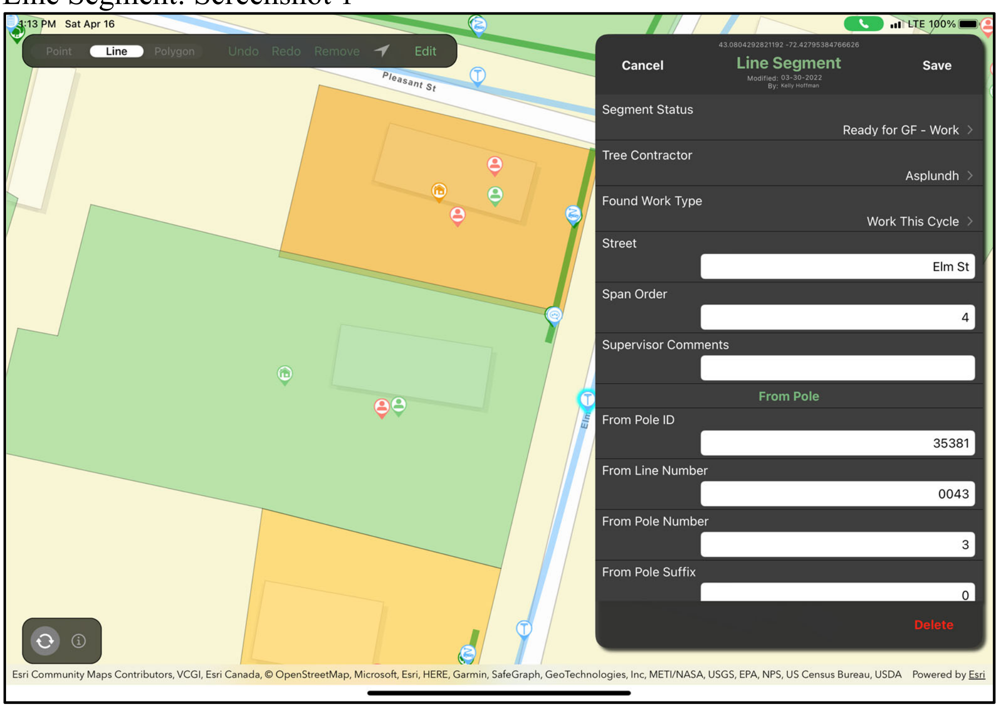


Docket No. DE 21-138 Request No. DOE TS 1-2

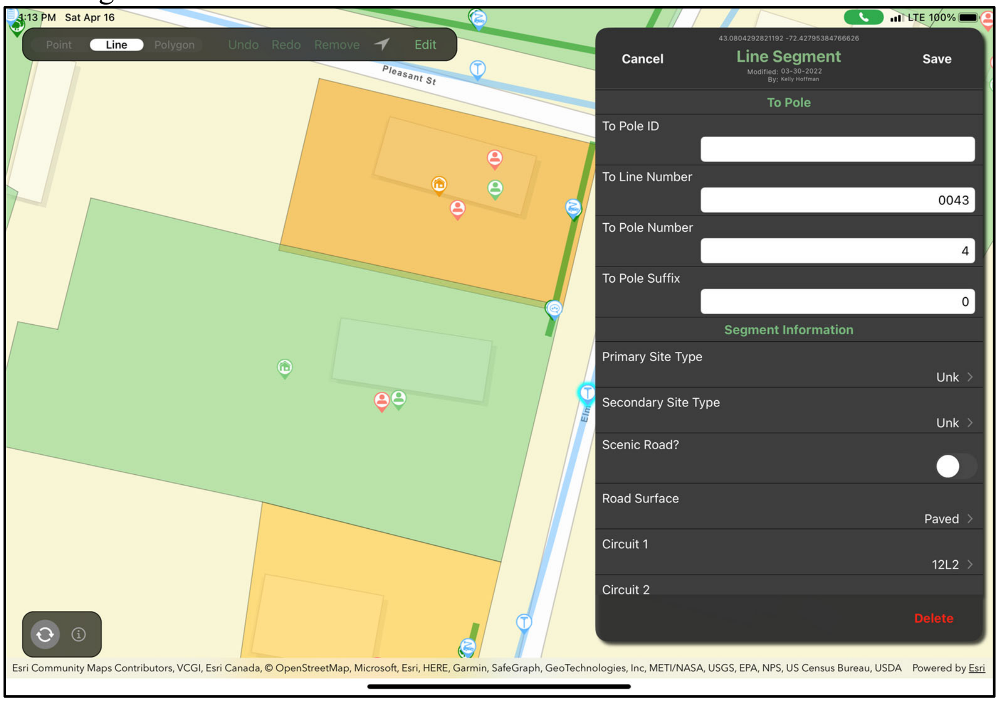
Vegetation: Screenshot 4



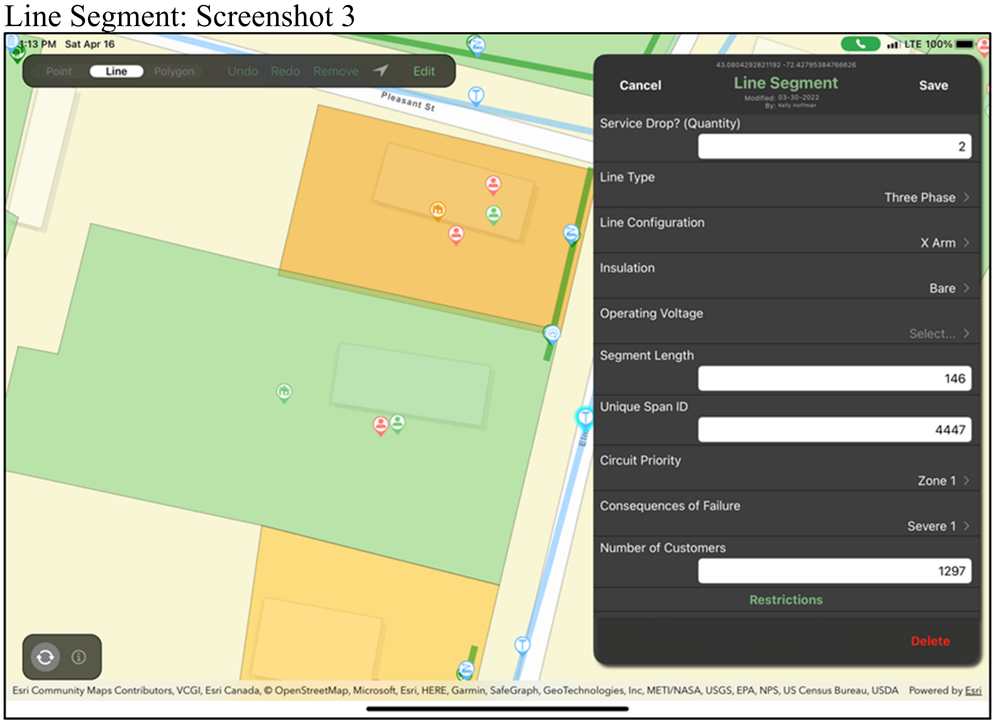
Line Segment: Screenshot 1



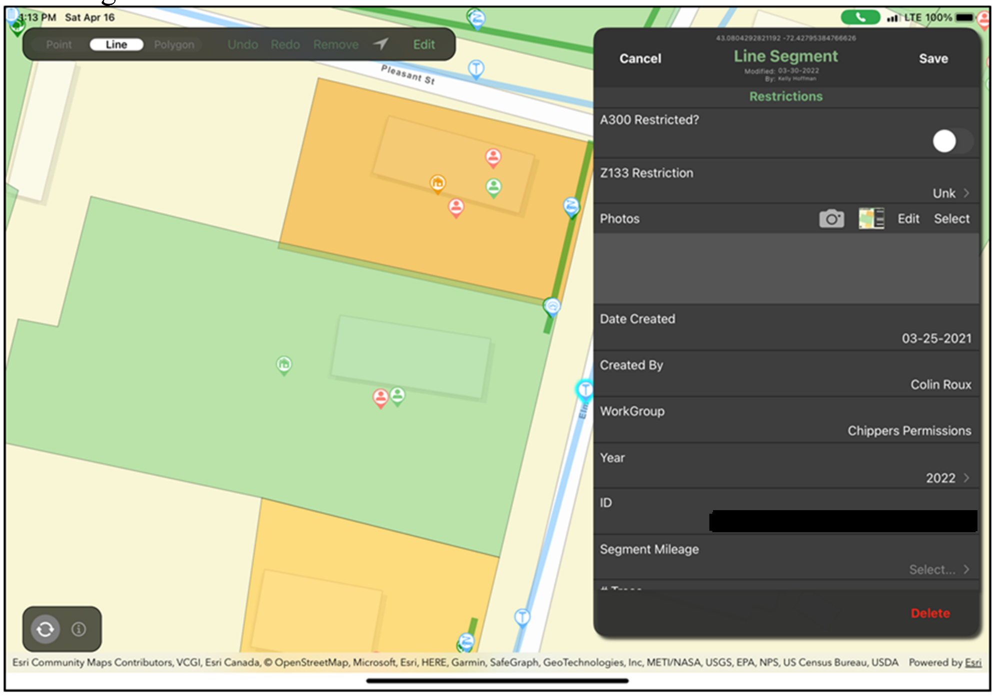
Line Segment: Screenshot 2



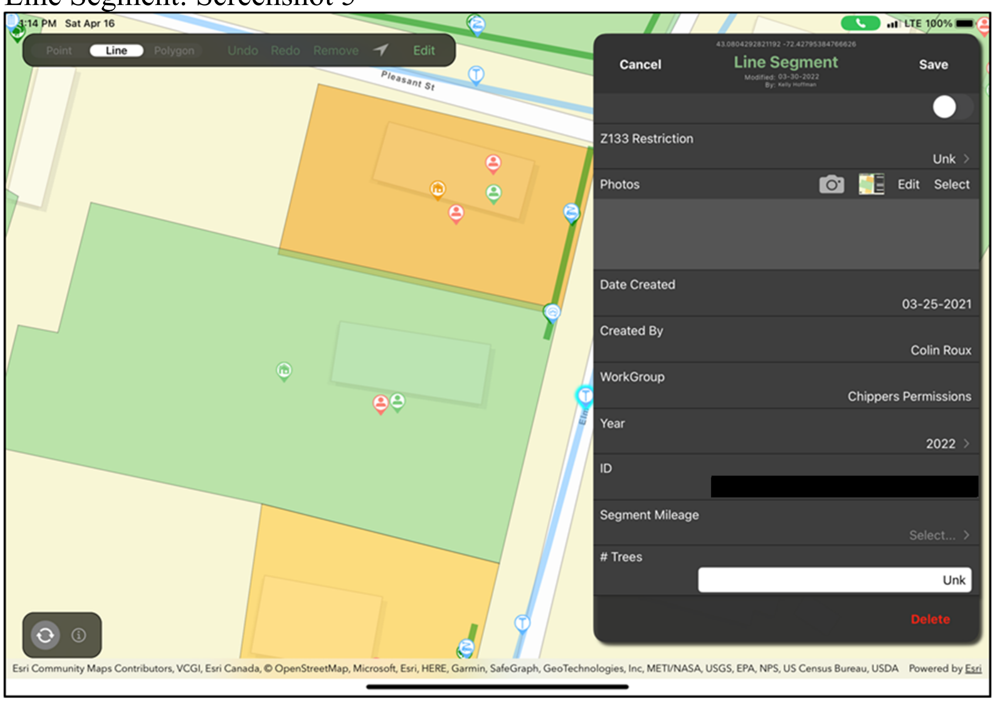
Line Segment: Screenshot 3



Line Segment: Screenshot 4



Line Segment: Screenshot 5



Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Office of the Consumer Advocate Data Requests - Set 5

Date Request Received: 10/4/23
Request No: OCA 5-33

Date of Response: 10/18/23
Respondent: Kristin Jardin
Daniel Dane
Heather Green

REQUEST:

Vegetation Management (IVM). Refer to Table 3 in Green/Sparkman Testimony (Bates II-545). Are the amounts shown included in Schedule RR-3.12 (Bates II-348) If so, please reconcile the amounts in Table 3 with Schedule RR-3.12

RESPONSE:

Yes. IVM / Herbicide in ROW is listed on line 16 in Schedule RR-3.12 (Bates II-348). While responding to this request, the Company identified some inconsistencies/errors in Table 3 of the joint testimony of Green and Sparkman and to Attachment HG-4. Please see below for the updated Table 3 and Attachment 23-039 OCA 5-33.xlsx for the updated Attachment HG-4 which reflects updates specifically to lines 15-19 and 32. The Company will update Schedule RR-3.12 line 15 of the revenue requirement to reflect an update to the Sub-Transmission Right of Way Clearing amount in its next update of the revenue requirement in this proceeding. Additionally, the Company will be providing revised responses to DOE 1-1, DOE 3-5 and DOE 6-23 to reflect these updates.

Table 3

			Escalator	Rate Year 1	Rate Year 2	Rate Year 3
Vegetation Management		5 Yr				
# Miles	165.09	175.00		175.00	175.00	175.00
IVM/ Herbicide in ROW	$69,210	$69,210	Specific	~~$175~~ $64,605	$32,500	$5,000
Pollinators Education/Habitat	$5,000	$5,000	5%	~~$64,605~~ $5,125	$5,381	$5,650
Monarch Butterfly Conservation	$20,000	$20,000	5%	~~$5,125~~ $20,500	$21,525	$22,601
Sub-Transmission Right of Way Clearing	$0	$80,000	5%	~~$20,500~~ $82,000	$86,100	$90,405
Total VMP O&M Expenses	$94,210	$174,210		~~$82,000~~ $172,230	$145,506	$123,657

Docket No. DE 23-039
Attachment OCA 5-33.2
Page 1 of 1

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1											
2											
3											
4											
5											
6											
7											
8						Bridge Period		Rate Year 1			
9					Escalator	**Q1 2023**	**Q2 2023**	**Q3 2023**	**Q4 2023**	**Q1 2024**	**Q2 2024**
10	Vegetation Management	Vegetation Management		5 Yr							
11	# Miles	# Miles	165.09	175.00		41.27	41.27	43.75	43.75	43.75	43.75
12	Type of Work Attachment 23-039 DOE 3-5	Type of Work Attachment 23-039 DOE 1-1.5	2023 Budget ($2.4M)	2023 Budget (Full Services)	Annual Escalator	2023 Q1 Budget	2023 Q2 Budget	2023 Q3 Budget	2023 Q4 Budget	2024 Q1 Budget	2024 Q2 Budget
13											
14	Work Planners for Veg Plan	Cycle Administration	$220,000	$375,000	5%	$55,000	$55,000	$93,750	$93,750	$98,438	$98,438
15	Spot Tree Trimming	Spot Work	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910
16	Trouble and Restoration Maintenance	Trouble and Restoration Maintenance	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910
17	Interim Trimming	Interim Trimming	$46,500	$60,610	5%	$11,625	$11,625	$15,152	$15,152	$15,910	$15,910
18	Planned Cycle Trimming	Cycle Trim	$1,435,663	$1,418,025	10%	$358,916	$358,916	$354,506	$354,506	$389,957	$389,957
19	Police Detail Expenses - Cycle Trimming & Other	Traffic Control	$324,836	$607,099	5%	$81,209	$81,209	$151,775	$151,775	$159,363	$159,363
20	Hazard Tree Removal	Fall-In Risk Tree Removals	$50,000	$437,500	5%	$12,500	$12,500	$109,375	$109,375	$114,844	$114,844
21	Hazard Tree Removal - Catch up	Grow-In Risk Tree Removals	$0	$437,500	5%	$0	$0	$109,375	$109,375	$114,844	$114,844
22	Brush & Limb Lead Removal	Brush & Limb Lead Removal	$0	$135,200	5%	$0	$0	$33,800	$33,800	$35,490	$35,490
23	Tree Planting	Tree Planting	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250
24	IVM/ Herbicide in ROW	ROW IVM: Sub-Transmission Herbicide	$69,210	$69,210	Specific	$17,303	$17,303	$17,303	$17,303	$15,000	$15,000
25	Polinator Education/Habitat	ROW IVM: Pollinator Education/Habitat	$5,000	$5,000	5%	$1,250	$1,250	$1,250	$1,250	$1,313	$1,313
26	Monarch Butterfly Conservation	ROW IVM: Monarch Butterfly Conservation	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250
27	AI- Dash Software	VM Software: AI- Dash	$42,000	$42,000	5%	$10,500	$10,500	$10,500	$10,500	$11,025	$11,025
28	Mailers/ Permissions	Printed Material	$3,500	$5,000	5%	$875	$875	$1,250	$1,250	$1,313	$1,313
29	Permit Fees	Permit Fees	$25,000	$25,000	5%	$6,250	$6,250	$6,250	$6,250	$6,563	$6,563
30	Terra Spectrum	VM Software: Terra Spectrum	$25,000	$25,000	5%	$6,250	$6,250	$6,250	$6,250	$6,563	$6,563
31	Training	Training	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250
32	Sub-Transmission Right of Way Clearing	ROW IVM: Sub-Transmission Clearing	$0	$80,000	5%	$0	$0	$20,000	$20,000	$21,000	$21,000
33	Make Safe Removals	Make Safe Work	$20,000	$20,000	5%	$5,000	$5,000	$5,000	$5,000	$5,250	$5,250
34		Program Assessment	$0	$0	5%	$0	$0	$0	$0	$0	$0
35	Total VMP O&M Expenses	Total VMP O&M Expenses	$2,419,709	$3,923,363		$604,927	$604,927	$980,841	$980,841	$1,044,441	$1,044,441
36											
37	Calendar Year	Calendar Year						CY23	$3,171,536		
38								RY1	$4,050,563		
39		Bridge period spending = 50% of allowed rates ($2.2M) + 10% overage = $1.21M									
40		Assumes a reset of trim cycles - no catch up of deferred miles									
41		Assumes a 5 year trim cycle consistent with Puc 307.10									
42		Assumes full reconciliation of vegetation management costs through the Revenue Adjusment Charge (RAC) - actuals compared to forecasted rate year									

(a)	(m)	(n)	(o)	(p)	(q)	®	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)
1														
2														
3														
4														
5														
6														
7														
8	Rate Year 2				Rate Year 3									
9	**Q3 2024**	**Q4 2024**	**Q1 2025**	**Q2 2025**	**Q3 2025**	**Q4 2025**	**Q1 2026**	**Q2 2026**	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
10														
11	43.75	43.75	43.75	43.75	43.75	43.75	43.75	43.75						
12	2024 Q3 Budget	2024 Q4 Budget	2025 Q1 Budget	2025 Q2 Budget	2025 Q3 Budget	2025 Q4 Budget	2026 Q1 Budget	2026 Q2 Budget	2026 Q3 Budget	2026 Q4 Budget				
13														
14	$98,438	$98,438	$103,359	$103,359	$103,359	$103,359	$108,527	$108,527	$108,527	$108,527				
15	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
16	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
17	$15,910	$15,910	$16,706	$16,706	$16,706	$16,706	$17,541	$17,541	$17,541	$17,541				
18	$389,957	$389,957	$428,953	$428,953	$428,953	$428,953	$471,848	$471,848	$471,848	$471,848				
19	$159,363	$159,363	$167,332	$167,332	$167,332	$167,332	$175,698	$175,698	$175,698	$175,698				
20	$114,844	$114,844	$120,586	$120,586	$120,586	$120,586	$126,615	$126,615	$126,615	$126,615				
21	$114,844	$114,844	$120,586	$120,586	$120,586	$120,586	$126,615	$126,615	$126,615	$126,615				
22	$35,490	$35,490	$37,265	$37,265	$37,265	$37,265	$39,128	$39,128	$39,128	$39,128				
23	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
24	$15,000	$15,000	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250	$1,250				
25	$1,313	$1,313	$1,378	$1,378	$1,378	$1,378	$1,447	$1,447	$1,447	$1,447				
26	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
27	$11,025	$11,025	$11,576	$11,576	$11,576	$11,576	$12,155	$12,155	$12,155	$12,155				
28	$1,313	$1,313	$1,378	$1,378	$1,378	$1,378	$1,447	$1,447	$1,447	$1,447				
29	$6,563	$6,563	$6,891	$6,891	$6,891	$6,891	$7,235	$7,235	$7,235	$7,235				
30	$6,563	$6,563	$6,891	$6,891	$6,891	$6,891	$7,235	$7,235	$7,235	$7,235				
31	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
32	$21,000	$21,000	$22,050	$22,050	$22,050	$22,050	$23,153	$23,153	$23,153	$23,153				
33	$5,250	$5,250	$5,513	$5,513	$5,513	$5,513	$5,788	$5,788	$5,788	$5,788				
34	$0	$0	$16,596	$16,596	$16,596	$0	$0	$0	$0	$0				
35	$1,044,441	$1,044,441	$1,118,256	$1,118,256	$1,118,256	$1,101,660	$1,178,129	$1,178,129	$1,178,129	$1,178,129				
36														
37	CY24	$4,177,762			CY25	$4,456,430		$4,456,430	CY26	$4,712,514				
38	RY2	$4,325,394			RY3	$4,576,174		$4,576,174						
39														
40														
41														
42														

VMP Definitions

Brush & Limb Lead Removal (Planned)
This captures all charges for removal of 4.5”-8.5” diameter* trees or limb leads 8.5” diameter or greater on the system typically performed with cycle work. However, may be performed off cycle as catchup.
DNH.VEGMGNT.VM.1220.5931

Cycle Administration: (Planned)
This captures the activities around the work planning and administrative processes. Work planning is a systematic approach to prescribing vegetation maintenance work around power lines. It involves the patrol and inspection of the power line corridor on a span-by-span basis. Work planning begins with an experienced (and typically degreed) forester working as an inspector (work planner). The clearances and tree selection parameters are pre-determined by the utility and are applied to the field conditions. Work is recorded in a software management system and assigned. The prescribed work is executed by the line clearance contractor. The work planning process concludes with a review of the work by auditing. Additional administrative responsibilities include, but are not limited to: process implementation and improvements, data integrity management, Terra Spectrum Field Note build and support, support of invoice processing, quality control, assisting in auditing,providing training, p[roviding work coordination and more.
DNH.VEGMGNT.VM.1000

Cycle Trim: (Planned)
This captures charges for annual fiscal year of obtaining permissions and execution of planned cycle pruning, brush cutting, clearing and vine removals activities but does not include police detail expenses, removals 5” in diameter or greater or work planning.
DNH.VEGMGNT.VM.1215

Enhanced Risk Tree Removal (ERTM): (Planned) (Not in current budget. Placeholder for future.)
Captures all charges for the hazard tree removal program directed at improving reliability of on and off cycle poor performing circuits based on removing dead, dying and/or structurally weak trees, limbs and leads on the three phase portions of those targeted circuits using a Customer Served approach beyond each major reliability device point including the lockout section or station breaker to the first reliability device.
DNH.VEGMGNT.VM.1220.5933

Fall-In Risk Tree Removals (Planned)
This captures all charges for removal of fall-in (mostly growing outside the corridor) risk related dead, dying and/or structurally weak trees, limbs and leads typically performed with cycle work. However, may be performed off cycle as catchup.
DNH.VEGMGNT.VM.1220.5933

Grow-In Risk Tree Removals (Planned)
This captures all charges for tree removals growing within the corridor typically performed with cycle work. However, may be performed off cycle as catchup. Typically, the diameter is 8.6” in diameter or greater. Removal of these trees helps establish the corridor to maintain in the future.
DNH.VEGMGNT.VM.1220.5932

VMP Definitions

Integrated Vegetation Management (IVM)
A system of managing plant communities in which compatible and incompatible vegetation are identified; action thresholds are determined; tolerance levels are established; and control methods are evaluated, selected and applied to achieve management goals and maintenance objectives. IVM often integrates multiple methods to promote sustainable plant communities that are compatible with management goals

Interim Trimming: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for charges for mitigation of tree conditions that threaten reliability of one or more sections of primary conductor on a circuit or circuits not contained in the current fiscal year's annual plan of work.
DNH.VEGMGNT.VM.1235

Make Safe Work: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for assistance to private tree work as required to allow a landowner to perform property maintenance while following industry safety requirements
DNH.VEGMGNT.VM.1010.5932

Permit Fees
This captures all charges for activities related to permitting, ie environmental permits, railroad permits, scenic roads, etc.
DNH.VEGMGNT.VM.1215.5932

Printed Material
This captures all charges for activities related to printed material to perform program needs: mailers, door hangers, tree removal forms, traffic control forms, etc.
DNH.VEGMGNT.VM.1215.5932

Program Assessment
A review and assessment of the vegetation maintenance program evaluating efficiency and effectiveness. Performed by a 3rd party contractor.
DNH.VEGMGNT.VM.1215.5932

VM Software
Vegetation Management software includes Ai-Dash and Terra Spectrum and others as needed. Ai-Dash and Terra Spectrum are 2 software tools utilized as work management system, evaluation tool, and reporting or projecting experiences or expectations.
DNH.VEGMGNT.VM.1215.5932

ROW IVM: Monarch Butterfly Conservation
This captures all charges for activities related to Monarch Butterfly Conservation to aid in effective and efficient IVM.
DNH.VEGMGNT.VM.1280

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VMP Definitions

ROW IVM: Pollinator Education/Habitat
This captures all charges for activities related to incorporating promotion of pollinator habitat and cultural activities to aid in effective and efficient IVM.
DNH.VEGMGNT.VM.1280

ROW IVM: Sub-Transmission Clearing (Floor & Side & Removals):
This captures all charges for activities related to cutting, clearing, herbicide application and tree removal on off-road distribution and substation supply lines up to 115kV.
DNH.VEGMGNT.VM.1280

ROW IVM: Sub-Transmission Herbicide
This captures all charges for activities related to herbicide application on off-road distribution and substation supply lines up to 115kV.
DNH.VEGMGNT.VM.1280.5934

Spot Work: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up of corrective action required, if any, to mitigate vegetation management concerns requested or reported by a customer between cycle work. Can usually be scheduled over next several weeks to months for efficiencies.
DNH.VEGMGNT.VM.1010.5931

Traffic Control: (Planned & Unplanned)
This captures all charges for traffic control expenses associated with annual planned cycle trim, tree removals, and unplanned work of spot trimming, trouble, interim work and other Vegetation Management work requiring traffic control.
DNH.VEGMGNT.VM.1218

Training
Scope of work, safety, software, process, or more training for program supervisors, administrators or crews as needed. Can be one on one or in group settings.
DNH.VEGMGNT.VM.1215.5932

Tree Planting:
This captures all charges for tree replacements in exchange for tree removals of full clearance, tree replacement to remediate property owner complaints, trees planted for Arbor Day events.
DNH.VEGMGNT.VM.1240

Trouble and Restoration Maintenance: (Unplanned)
This captures all charges for customer contact, field review, assignment, execution, and follow up for response and corrective action to mitigate isolated tree related trouble, overhead line requests to mitigate tree related trouble and storm responses not covered by a storm specific charge number. It typically requires immediate response. That is, cannot be schedule weeks or months later.
DNH.VEGMGNT.VM.1210

VM
Vegetation Management

*Diameter of trees is measured 4.5’ from the ground.

SUPPLEMENTAL

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Technical Session Data Requests - Set 2

Date Request Received: 11/3/23
Request No: DOE TS 2-5

Date of Supplemental Response: 12/6/23
Respondent: Kristin Jardin (i)
Daniel Dane (i)
Erin O'Brien (a-h)

REQUEST:

General Filing Requirements. Reference Puc 1604.01(a)(1)(a) BS, pages 1-4 on Bates p. I-006 to I-009 and FERC Form 1, pp. 24-28 of 163.

a. Please explain why the net utility plant amounts for 2022 are not the same on the filing requirements ($242,404,453) and FERC Form 1 ($242,052,576).

b. Please explain why the Total Current and Accrued Assets differ by almost $1 billion on the filing requirements ($1,044,954,833) and FERC Form 1 ($80,882,925).

c. Under current and accrued assets for accounts receivable from Assoc. Companies (146), please explain why the FERC Form 1 is blank and the filing requirements show over $964 million.

d. Under Deferred Debits for Other Regulatory Assets (182.3), please explain why the amounts differ by over $1.1 million.

e. For Total Deferred Debits, please explain why the FERC Form 1 ($5,934,753) and the filing requirements ($7,264,066) differ by over $1 million.

f. For Accounts Payable to Associated Companies (234), please explain why the FERC Form 1 ($75,125,573) and the filing requirements ($1,039,197,482) differ by almost $1 billion.

g. For Total Liabilities and Stockholder Equity, please explain why the FERC Form 1 ($328,891,720) and the filing requirements ($1,294,644,819) differ by almost $1 billion.

h. For all accounts and subtotals and totals shown in the filing requirements and the FERC Form 1, please show a table listing the amounts for each as shown in the filing requirement and the FERC Form 1 and calculate the variance between the two. Please provide an explanation for each of the variances. Please provide a live excel spreadsheet.

i. For subparts a-h, please explain which amount is used in rate base, a cite of where the amount is listed in the revenue requirement calculation, and how the Commission and Parties are to know which amounts are correct and can be used as the basis for this rate case.

Docket No. DE 23-039 Request No. DOE TS 2-5 (Supplemental)

INITIAL RESPONSE (11/20/23):

a. Please refer to Attachment 23-039 DOE TS 2-5, page 1. This difference occurs due to the Construction Work In Progress account (107) reflecting changes in the 1604 filing as outlined in the attachment.

b. The difference is due to the presentation of Accounts Receivable from Associated Companies. Please see (c) below. Please also refer to Attachment 23-039 DOE TS 2-5, pages 2-3, lines 43 and 125 which show how these amounts are reflected in accounts 146 (Amounts due from associated companies) and account 125 (amounts due to associated companies).

c. In the FERC Form 1, Accounts Receivable from and Accounts Payable to Associated Companies were shown on a net basis to remain consistent with the presentation from the previous year. In the 1604 filing requirement, these balances were shown gross as they appear in the trial balance. The result of the net balance in 2022 in account 234 for Accounts Payable is $(75,125,573) shown on the FERC Form 1. This balance is comprised of the $964,071,909 in Accounts Receivable (noted above in account 146) and ($1,039,197,482) in Accounts Payable (recorded in account 234), which is the gross presentation shown in the 1604 filing requirement. Please also refer to Attachment 23-039 DOE TS 2-5, pages 2-3, lines 43 and 125.

d. Please refer to Attachment 23-039 DOE TS 2-5, page 4 for details of the difference. As can be seen on page 4, the balance is comprised of adjustments corrected in response to data request DOE 11-14 in the amount of $496,268.87 and presentation differences between the 1604 and the FERC form 1 in the amount of $667,181.63.

e. The difference is due to those differences identified in (d) above, offset by the presentation of Miscellaneous Deferred Debit (186) balance. The 186 account was presented as a Miscellaneous Deferred Debit (186) in the filing requirements and as an Other Regulatory Asset (182.3) in the FERC Form 1. Please also refer to Attachment 23-039 DOE TS 2-5, pages 2 through 4.

f. The difference is due to the presentation of Accounts Receivable from Associated Companies as outlined in subpart (c) above. Please also refer to Attachment 23-039 DOE TS 2-5, pages 2-3.

g. This difference is comprised of (1) the presentation of Accounts Receivable from Associated Companies, as discussed in (c) above, (2) a regulatory liability in a debit position, presented as a regulatory asset in the filing requirement and an offset to the regulatory liabilities in the FERC Form 1, as shown in the reference at (d) above, and (3) the difference in Retained Earnings as discussed in the response to DOE 11-14. Please refer to Attachment 23-039 DOE TS 2-5, pages 2-3.

h. Please see the live Excel file Attachment 23-039 DOE TS 2-5.xlsx. The "BS Comparison" tab provides a table showing all accounts in the filing requirement and FERC Form 1, calculated difference between each line, and explanation for each of those variances.

i. Please see the table below for the requested information.

Docket No. DE 23-039 Request No. DOE TS 2-5 (Supplemental)

Question Subpart	Response
a	The difference in FERC account 107 Construction Work in Progress is excluded from the rate base calculation, not included in the revenue requirement schedules and does not impact the revenue requirement.
b	See the Company's response to subpart c below.
c	The difference in FERC account 146 is excluded from the rate base calculation, not included in the revenue requirement schedules and does not impact the revenue requirement.
d	FERC account 182 is reflected in the Company's filing in Schedule RR-4.4, Line 3. However, the Company did not include the entirety of FERC 182 in rate base in the revenue requirement. The differences in FERC 182 identified in the data request were not included in the Company's rate base calculation, not included in the revenue requirement schedules and do not impact the revenue requirement.
e	FERC account 186 is reflected in the Company's filing in Schedule RR-4.4, line 7. The differences in FERC 186 identified in the data request were not included in the Company's rate base calculation, not included in the revenue requirement schedules and do not impact the revenue requirement.
f	The difference in FERC account 234 is excluded from the rate base calculation, not included in the revenue requirement schedules and does not impact the revenue requirement.
g	See the responses above.
h	The Company's response to subpart h is not applicable to the revenue requirement schedules.

SUPPLEMENTAL RESPONSE (12/6/23):

Related to subparts b, c, f, and g:

The Company has identified that the Intercompany Accounts Receivable from Associated Companies (FERC account 146) and Accounts Payable to Associated Companies (FERC account 234) account balances were each overstated by the same amount as of December 31, 2022 on the Company's balance sheet. The Company has made the correction as of December 2023 and notes that there is no change in the net balance of intercompany receivables/payables following the correction of these accounts. An explanation follows.

As explained in the Company's initial response above, in the Company's legacy general ledger system, intercompany balances were recorded to the Intercompany Accounts Payable general ledger account and the intercompany balances were always reported on the financial statements as a net payable. In the Company's new general ledger, SAP, intercompany balances are shown on a gross basis -- receivables are recorded in Intercompany Accounts Receivable (FERC account 146), and payables are recorded in Intercompany Accounts Payable (FERC account 234). When the Company transitioned to SAP, the legacy general ledger balance was brought over to one general ledger account in SAP. A manual journal entry was recorded to separate balances into the Intercompany Accounts Receivable and Intercompany Accounts Payable accounts. In the process of separating those balances, the Company inadvertently increased both the receivable and payable by $572.9 million. This does not change the net position which has been reported. The incorrect increases were the result of accumulating the monthly net changes in the intercompany payable account instead of taking the ending balances as of September 30, 2022. While the net balance remained and continues to be accurate, the individual balances of the receivable and payable were overstated as of December 31, 2022.

Please refer to the table below for the revised 146 and 234 balance sheet accounts and a comparison to the amounts initially reported on the Company's balance sheet in Puc 1604.01(a)(1)(a) BS, pages 1-4 on Bates p. I-006 to I-009 which reflects that the amounts net out.

	Updated Result	**Initial Filing**	**Change**
Accounts Receivable from Assoc. Companies (146)	391,133,658.44	964,071,908.63	(572,938,250.19)
Accounts Payable to Associated Companies (234)	(466,259,231.37)	(1,039,197,481.56)	572,938,250.19
Net total	(75,125,572.93)	(75,125,572.93)	0

There is no change to the Company's 2022 FERC Form 1 and there is no impact to the Company's revenue requirement as described above in the responses to subparts b, c, f, and g.

SUPPLEMENTAL

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

DE 23-039
Distribution Service Rate Case

Department of Energy Technical Session Data Requests - Set 2

Date Request Received: 11/3/23
Request No: DOE TS 2-7

Date of Supplemental Response: 12/6/23
Respondent: Erin O'Brien

REQUEST:

General Filing Requirements. Reference Puc 1604.01(a)(1)(a) BS, page 1 of 4, Bates p. I-006 and Puc 1604.01(a)(1)(c) p. 2 of 13, Bates p. I-018. Please explain why the amounts for Accounts Receivable from Assoc. Companies (146) increase by almost $1 billion from Q4 2020 to the end of 2022 and from the beginning of 2022 to the end of 2022:

Q4 2020: $59,984
Q1 2021: $54,757
Q2 2021: $0
Q3 2021: $0
Q4 2021: $0
January 31, 2022: $0
December 31, 2022: $964,071,909

INITIAL RESPONSE (11/20/23):

The Accounts Receivable from Associated Companies (account 146) is offset against the Accounts Payable to Associated Companies (account 234) as shown in Puc 1604.01(a)(1)(a) BS, page 3 of 4, Bates p. I-008. This results in a net balance for 2022 in account 234 of $(75,125,573). This net balance is comprised of the $964,071,909 (noted above in account 146) and ($1,039,197,482) (recorded in account 234). Reviewing the Accounts Receivable from and Accounts Payable to Associated Companies on a net basis allows for the determination of the position of intercompany balances. In the Company's legacy general ledger system, the amounts were netted through Accounts Payable to Associated Companies (then titled "Due to/from" accounts) and therefore reflected $0 balances as the net of the balances was a payable amount. In SAP, the amounts are shown in the trial balance on a gross basis.

SUPPLEMENTAL RESPONSE (12/6/23):

Please see the Company's supplemental response to DOE TS 2-5 for an update to the Accounts Receivable from Associated Companies (account 146) and the Accounts Payable to Associated

Companies (account 234) balances as shown in Puc 1604.01(a)(1)(a) BS, page 3 of 4, Bates p. I-008. This net balance is comprised of the $391,133,6658 (as revised in DOE TS 2-5 in account 146) and ($466,259,231) (as revised in DOE TS 2-5 in account 234).

Adam M. Hall
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November 15, 2022

Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DE 22-043; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Monthly EAP Reconciliation Report — October 2022

Enclosed for filing please find Liberty's Monthly EAP Reconciliation Report. Please note this report has been filed via the Commission's Electronic Report Filing system.

On October 3, 2022, Liberty transitioned to a new financial and billing system. Due to this change, the October 2022 Number of Active Participants by Discount Tier Levels and Amounts and Aging Report information provided monthly in the EAP filing is not available at this time. Liberty will file this information as soon as it is available.

Thank you for your attention to this matter. Please do not hesitate to call if you have any questions.

Sincerely,

Adam M Hall

Adam M. Hall

Enclosures

Cc: OCA Litigation

Electric Assistance Program
System Benefits Charge Reconciliation Report
October-22

Liberty Utilities (Granite State Electric)

			Imputed	Billed kWh	Difference
Retail Delivery kWh			52,313,897	52,313,897	-
SBC Low Income EAP Rate		$	0.0015		
SBC Low Income EAP Billed Amount		$	78,470.85		
Interest on 10% Reserve Fund Balance (1)		$	120.73		
SBC Low Income EAP Funding		$	78,591.58		
EAP Costs					
Discounts Applied to Customers Bills	$ 62,779.03				
Payments to Community Action Agencies(2)	$ -				
Discounts Applied to Customers Bills - Marketer(3)	$ 1,485.55				
Other Costs	$ -				
Total EAP Costs		$	64,264.58		
SBC Low Income EAP Balance		**$**	**14,327.00**		
Total amount due to State of New Hampshire Treasury		**$**	**14,327.00**		
Program to Date Reserve Balance		$	37,923.49		
Interest on reserve at 0.0374829					

(1) Interest rate / 365 (x) # of days in month (x) Reserve: Pursuant to Order No. 24,329 in Docket DE 03-195 State-wide Low Income Electric Assistance Program approving the Settlement Agreement, Liberty Utilities is paying interest on the reserve balance of $37,923.49. The interest rate is based on the three month London Interbank Offer Rates (LIBOR) on the first business day of the month.

(2) The invoice for the payment to Belknap CAA was received on November 3, 2022, and will be included in November's 2022 payment. Source: G/L 8830-2-0000-20-2142-2542

(3) Source: G/L 8830-2-0000-20-2142-2543

Craig A. Holden
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December 15, 2022
Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DE 22-043; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Monthly EAP Reconciliation Report — November 2022

Enclosed for filing please find Liberty's Monthly EAP Reconciliation Report. Please note this report has been filed via the Commission's Electronic Report Filing system.

On October 3, 2022, Liberty transitioned to a new financial and billing system. Due to this change, the November 2022 Number of Active Participants by Discount Tier Levels and Amounts and Aging Report information provided monthly in the EAP filing is not available at this time. Liberty will file this information as soon as it is available.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,
/s/Craig A. Holden

Craig A. Holden

Enclosures

Cc: OCA Litigation

Electric Assistance Program
System Benefits Charge Reconciliation Report
November-22

Liberty Utilities (Granite State Electric)

			Imputed	Billed kWh	Difference
Retail Delivery kWh			52,103,273	52,103,273	(0)
SBC Low Income EAP Rate			$ 0.0015		
SBC Low Income EAP Billed Amount			$ 78,154.91		
Interest on 10% Reserve Fund Balance (1)			$ 139.01		
SBC Low Income EAP Funding			$ 78,293.92		
EAP Costs					
Discounts Applied to Customers Bills	$	60,210.36			
Payments to Community Action Agencies(2)	$	42,887.01			
Discounts Applied to Customers Bills - Marketer(3)	$	1,796.88			
Other Costs	$	-			
Total EAP Costs			$ 104,894.25		
SBC Low Income EAP Balance			**$ (26,600.33)**		
Total amount due to (from) State of New Hampshire Treasury			**$ (26,600.33)**		
Program to Date Reserve Balance			$ 37,923.49		
Interest on reserve at 0.0445971					

(1) Interest rate / 365 (x) # of days in month (x) Reserve: Pursuant to Order No. 24,329 in Docket DE 03-195 State-wide Low Income Electric Assistance Program approving the Settlement Agreement, Liberty Utilities is paying interest on the reserve balance of $37,923.49. The interest rate is based on the three month London Interbank Offer Rates (LIBOR) on the first business day of the month.

(2) The September, October, and Advance Request for FY 2022-2023 invoices from Belknap CAA are included in the current month. Source: G/L 3071-240300-10254000

(3) Source: G/L 3071-241210-10254000

Craig A. Holden
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January 13, 2023
Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DE 22-043; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Monthly EAP Reconciliation Report — December 2022

Enclosed for filing please find Liberty's Monthly EAP Reconciliation Report. Please note this report has been filed via the Commission's Electronic Report Filing system.

On October 3, 2022, Liberty transitioned to a new financial and billing system. Due to this change, the October through December 2022 Number of Active Participants by Discount Tier Levels and Amounts and Aging Report information provided monthly in the EAP filing is not available. Liberty will file this information prior to next month's report.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,
/s/Craig A. Holden

Craig A. Holden

Enclosures

Cc: OCA Litigation

Electric Assistance Program
System Benefits Charge Reconciliation Report
December 2022

Liberty Utilities (Granite State Electric)

			Imputed	Billed kWh	Difference
Retail Delivery kWh			72,161,020	72,161,022	2
SBC Low Income EAP Rate			$ 0.0015		
SBC Low Income EAP Billed Amount			$ 108,241.53		
Interest on 10% Reserve Fund Balance (1)			$ 153.48		
SBC Low Income EAP Funding			$ 108,395.01		
EAP Costs					
Discounts Applied to Customers Bills	$	57,930.18			
Discounts Applied to Customers Bills - Marketer(2)	$	1,438.94			
Payments to Community Action Agencies(3)	$	13,180.97			
Other Costs	$	-			
Total EAP Costs			$ 72,550.09		
SBC Low Income EAP Balance			**$ 35,844.92**		
Total amount due to (from) State of New Hampshire Treasury			**$ 35,844.92**		
Program to Date Reserve Balance			$ 37,923.49		
Interest on reserve at 0.04765					

(1) Interest rate / 365 (x) # of days in month (x) Reserve: Pursuant to Order No. 24,329 in Docket DE 03-195 State-wide Low Income Electric Assistance Program approving the Settlement Agreement, Liberty Utilities is paying interest on the reserve balance of $37,923.49. The interest rate is based on the three month London Interbank Offer Rates (LIBOR) on the first business day of the month.

(2) Source: G/L 3071-241210-10254000

(3) The November invoice from Belknap CAA is included in the current month. Source: G/L 3071-240300-10254000

Liberty

Craig A. Holden
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February 8, 2023

Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DE 22-043; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Monthly EAP Reconciliation Report — December 2022 Update

Enclosed for filing please find Liberty's update to its December 2022 Monthly EAP Reconciliation Report. This report replaces the report submitted on January 13, 2023. Please note this report has been filed via the Commission's Electronic Report Filing system.

On October 3, 2022, Liberty transitioned to a new financial and billing system. Due to this change, the "Number of Active EAP Participants by Discount Tier Levels and Amounts" and "Aging Report" information were not available and were excluded from the original report. This report now includes all required pages.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,
/s/Craig A. Holden

Craig A. Holden

Enclosures

Cc: OCA Litigation

Electric Assistance Program
System Benefits Charge Reconciliation Report
December 2022

Liberty Utilities (Granite State Electric)

			Imputed	Billed kWh	Difference
Retail Delivery kWh			72,161,020	72,161,022	2
SBC Low Income EAP Rate			$ 0.0015		
SBC Low Income EAP Billed Amount			$ 108,241.53		
Interest on 10% Reserve Fund Balance [1]			$ 153.48		
SBC Low Income EAP Funding			$ 108,395.01		
EAP Costs					
Discounts Applied to Customers Bills	$	62,138.81			
Discounts Applied to Customers Bills - Marketer[2]	$	1,438.94			
Reversal of September Discount Accrual [4]	$	(4,208.63)			
Payments to Community Action Agencies[3]	$	13,180.97			
Other Costs	$	-			
Total EAP Costs			$ 72,550.09		
SBC Low Income EAP Balance			**$ 35,844.92**		
Total amount due to (from) State of New Hampshire Treasury			**$ 35,844.92**		
Program to Date Reserve Balance			$ 37,923.49		
Interest on reserve at 0.04765					

(1) Interest rate / 365 (x) # of days in month (x) Reserve: Pursuant to Order No. 24,329 in Docket DE 03-195 State-wide Low Income Electric Assistance Program approving the Settlement Agreement, Liberty Utilities is paying interest on the reserve balance of $37,923.49. The interest rate is based on the three month London Interbank Offer Rates (LIBOR) on the first business day of the month.

(2) Source: G/L 3071-241210-10254000

(3) The November invoice from Belknap CAA is included in the current month. Source: G/L 3071-240300-10254000

(4) September 2022 discounts applied amount included a $4,208.63 accrual for pre-SAP billing system cutover.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Electric Assistance Program
Number of Active EAP Participants by Discount Tier Levels and Amounts
December 2022

	Number of Active Participants	Discount Tier	% per Tier Participants To Total Participants	Discount Amount	% per Tier Discount To Total Discounts
	0	1	0.0%	$ -	0.0%
	533	2	44.1%	11,697.69	18.4%
	169	3	14.0%	6,715.16	10.6%
	189	4	15.6%	11,505.64	18.1%
	169	5	14.0%	13,478.40	21.2%
	148	6	12.3%	20,180.86	31.7%
TOTAL*	1,208		100.0%	$ 63,577.75	100.0%

	Discount	% of Federal Poverty Guidelines
2	8%	151% to 200%
3	22%	126% to 150%
4	36%	101% to 125%
5	52%	76% to 100%
6	76%	Up to 75%

*The total may not sum because some customers moved tiers during the month.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Electric Assistance Program (EAP)
Aging Report
December 2022

Non-EAP Customers

	Percentage of Customers		Balance
Current Balance	75.5%	$	6,365,714.34
1st Arrears	9.8%	$	1,316,437.03
2nd Arrears	5.0%	$	819,675.37
3rd Arrears	3.4%	$	614,772.97
4th Arrears	6.3%	$	1,512,691.71
Total	100.0%	$	10,629,291.42
Customer Count			30,004

EAP Customers

	Percentage of Customers		Balance
Current Balance	53.9%	$	191,604.86
1st Arrears	10.1%	$	94,285.82
2nd Arrears	8.1%	$	76,466.74
3rd Arrears	5.7%	$	61,853.52
4th Arrears	22.2%	$	370,728.97
Total	100.0%	$	794,939.91
Customer Count			1,208

[1] Arrears data is as of December 31, 2022
[2] EAP Customer data includes customers receiving a discount in the current month.

James M. King
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April 17, 2023
Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DE 22-043; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Monthly EAP Reconciliation Report — March 2023

Enclosed for filing please find Liberty's Monthly EAP Reconciliation Report. Please note this report has been filed via the Commission's Electronic Report Filing system.

At the time of this filing, information for Active Participants by Discount Tier Levels and Amounts and Aging Report information provided monthly in the EAP filing was not available. Liberty will provide this information when available.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,
/s/James M. King

James M. King

Enclosures

Cc: OCA Litigation

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Electric Assistance Program
System Benefits Charge Reconciliation Report
March 2023

Liberty Utilities (Granite State Electric)

			Imputed	Billed kWh	Difference
Retail Delivery kWh			74,107,733	74,107,732	(1)
SBC Low Income EAP Rate			$ 0.0015		
SBC Low Income EAP Billed Amount			$ 111,161.60		
Interest on 10% Reserve Fund Balance [(1)]			$ 160.44		
SBC Low Income EAP Funding			$ 111,322.04		
EAP Costs					
Discounts Applied to Customers Bills	$ 75,022.64				
Discounts Applied to Customers Bills - Marketer[(2)]	$ 1,918.79				
Payments to Community Action Agencies[(3)]	$ 9,352.59				
Total EAP Costs			$ 86,294.02		
SBC Low Income EAP Balance			**$ 25,028.02**		
Total amount due to (from) State of New Hampshire Treasury			**$ 25,028.02**		
Program to Date Reserve Balance					
Interest on reserve at 0.0498114			$ 37,923.49		

(1) Interest rate / 365 (x) # of days in month (x) Reserve: Pursuant to Order No. 24,329 in Docket DE 03-195 State-wide Low Income Electric Assistance Program approving the Settlement Agreement, Liberty Utilities is paying interest on the reserve balance of $37,923.49. The interest rate is based on the three month London Interbank Offer Rates (LIBOR) on the first business day of the month.

(2) Source: G/L 3071-241210-1025400C

(3) The February invoice from Belknap CAA is included in the current month. Source: G/L 3071-240300-1025400C

James M. King
Analyst II, Rates and Regulatory Affairs
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April 25, 2023
Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DE 22-043; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Monthly EAP Reconciliation Report — March 2023 Update

Enclosed for filing please find Liberty's update to its March 2023 Monthly EAP Reconciliation Report. This report replaces the report submitted on April 17, 2023. Please note this report has been filed via the Commission's Electronic Report Filing system.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,
/s/James M. King

James M. King

Enclosures

Cc: OCA Litigation

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Electric Assistance Program
System Benefits Charge Reconciliation Report
March 2023

Liberty Utilities (Granite State Electric)

			Imputed	Billed kWh	Difference
Retail Delivery kWh			74,107,733	74,107,732	(1)
SBC Low Income EAP Rate		$	0.0015		
SBC Low Income EAP Billed Amount		$	111,161.60		
Interest on 10% Reserve Fund Balance [(1)]		$	160.44		
SBC Low Income EAP Funding		$	111,322.04		
EAP Costs					
Discounts Applied to Customers Bills	$ 75,022.64				
Discounts Applied to Customers Bills - Marketer[(2)]	$ 1,918.79				
Payments to Community Action Agencies[(3)]	$ 9,352.59				
Total EAP Costs		$	86,294.02		
SBC Low Income EAP Balance		**$**	**25,028.02**		
Total amount due to (from) State of New Hampshire Treasury		**$**	**25,028.02**		
Program to Date Reserve Balance					
Interest on reserve at 0.0498114		$	37,923.49		

(1) Interest rate / 365 (x) # of days in month (x) Reserve: Pursuant to Order No. 24,329 in Docket DE 03-195 State-wide Low Income Electric Assistance Program approving the Settlement Agreement, Liberty Utilities is paying interest on the reserve balance of $37,923.49. The interest rate is based on the three month London Interbank Offer Rates (LIBOR) on the first business day of the month.

(2) Source: G/L 3071-241210-1025400C

(3) The February invoice from Belknap CAA is included in the current month. Source: G/L 3071-240300-1025400C

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Electric Assistance Program
Number of Active EAP Participants by Discount Tier Levels and Amounts
March 2023

	Number of Active Participants	Discount Tier	% per Tier Participants To Total Participants	Discount Amount	% per Tier Discount To Total Discounts
	0	1	0.0%	$ -	0.0%
	621	2	40.4%	8,149.03	10.6%
	210	3	13.7%	7,270.36	9.4%
	255	4	16.6%	14,791.04	19.2%
	230	5	15.0%	17,561.56	22.8%
	222	6	14.4%	29,169.44	37.9%
TOTAL*	1,538		100.0%	$ 76,941.43	100.0%

	Discount	% of Federal Poverty Guidelines
2	8%	151% to 200%
3	22%	126% to 150%
4	36%	101% to 125%
5	52%	76% to 100%
6	76%	Up to 75%

*The total may not sum because some customers moved tiers during the month

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Electric Assistance Program
Aging Report
March 2023

Non-EAP Customers

	Percentage of Customers		Balance
Current Balance	81.9%	$	9,899,139.18
1st Arrears	3.3%	$	1,111,232.04
2nd Arrears	1.9%	$	584,836.23
3rd Arrears	1.7%	$	428,050.46
4th Arrears	11.2%	$	1,612,550.39
Total Arrears	100.0%	$	13,635,808.30
Customer Count			31,945

EAP Customers

Current Balance	56.6%	$	340,101.28
1st Arrears	7.7%	$	88,903.92
2nd Arrears	6.6%	$	49,112.58
3rd Arrears	3.1%	$	38,270.17
4th Arrears	26.1%	$	212,201.84
Total Arrears	100.0%	$	728,589.79
Customer Count			1,205

[1] Arrears data is as current month end.
[2] EAP Customer data includes customers receiving a discount in the current month.

James M. King
Analyst II, Rates and Regulatory Affairs
15 Buttrick Rd.
Londonderry, NH 03053
978-846-5039
James.King@libertyutilities.com

May 15, 2023

Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DE 22-043; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Monthly EAP Reconciliation Report — April 2023

Enclosed for filing please find Liberty's Monthly EAP Reconciliation Report. Please note this report has been filed via the Commission's Electronic Report Filing system.

At the time of this filing, information for Active Participants by Discount Tier Levels and Amounts and Aging Report information provided monthly in the EAP filing was not available. Liberty will provide this information when available.

Thank you for your attention to this matter. Please do not hesitate to contact me if you have any questions.

Sincerely,
/s/James M. King

James M. King

Enclosures

Cc: OCA Litigation

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Electric Assistance Program
System Benefits Charge Reconciliation Report
April 2023

Liberty Utilities (Granite State Electric)

			Imputed	Billed kWh	Difference
Retail Delivery kWh			69,931,587	69,931,587	0
SBC Low Income EAP Rate			$ 0.0015		
SBC Low Income EAP Billed Amount			$ 104,897.38		
Interest on 10% Reserve Fund Balance [(1)]			$ 162.79		
SBC Low Income EAP Funding			$ 105,060.17		
EAP Costs					
Discounts Applied to Customers Bills	$ 69,986.89				
Discounts Applied to Customers Bills - Marketer[(2)]	$ 1,857.34				
Payments to Community Action Agencies[(3)]	$ 10,067.77				
Total EAP Costs			$ 81,912.00		
SBC Low Income EAP Balance			**$ 23,148.17**		
Total amount due to (from) State of New Hampshire Treasury			**$ 23,148.17**		
Program to Date Reserve Balance			$ 37,923.49		
Interest on reserve at 0.0522257					

(1) Interest rate / 365 (x) # of days in month (x) Reserve: Pursuant to Order No. 24,329 in Docket DE 03-195 State-wide Low Income Electric Assistance Program approving the Settlement Agreement, Liberty Utilities is paying interest on the reserve balance of $37,923.49. The interest rate is based on the three month London Interbank Offer Rates (LIBOR) on the first business day of the month.

(2) Source: G/L 3071-241210-1025400C

(3) The March invoice from Belknap CAA is included in the current month. Source: G/L 3071-240300-1025400C

Liberty™

November 27, 2023
Via Electronic Report Filing

Daniel Goldner
Chairman
New Hampshire Public Utilities Commission
21 South Fruit St., Suite 10
Concord, NH 03301-2429

Dear Chairman Goldner:

Re: DG 11-040; Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Annual Residential Customer Satisfaction Survey — 2023

Pursuant to the Settlement Agreement approved by Commission Order No. 25,370 (May 30, 2012) in Docket No. DG 11-040, enclosed please find Liberty's Annual Residential Customer Satisfaction Survey results. Please note this report has been filed via the Commission's Electronic Report Filing system.

Thank you for your attention to this matter. Please do not hesitate to call if you have any questions.

Sincerely,

Erica L Menard

Erica L. Menard

Enclosure

Cc: Amanda Noonan
Paul Dexter, Esq.
Donald M. Kreis, Consumer Advocate

5021

Customer Satisfaction Tracking New Hampshire Electric

October 2023

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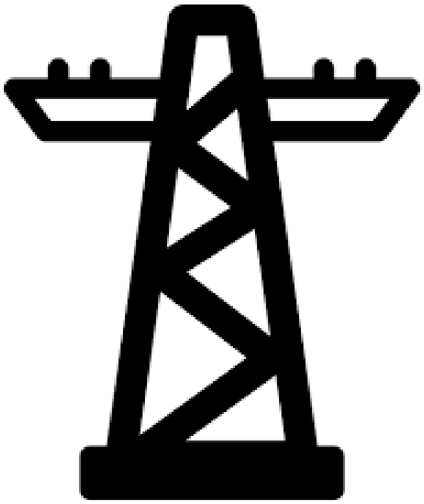
Liberty™

LUTH research



Background and Objectives

Background and Objectives

Screen & Evaluative Criteria

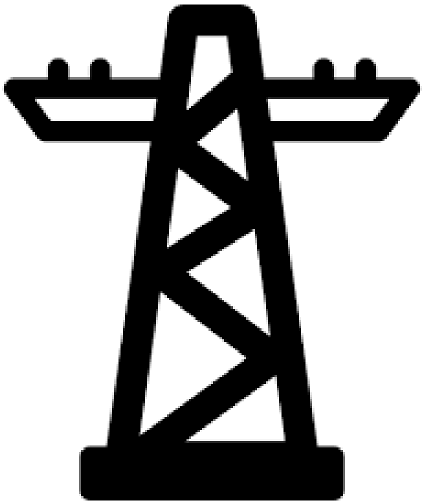
- Person in household who would contact local utility company or deal with bill
- Age 18 or older
- Aware Liberty is their local electricity provider

Method

- Web survey
- Qualification screener
- Analyze current customer satisfaction levels with Liberty among New Hampshire (NH) Electric Customers
- Compare current customer satisfaction levels with previous years to determine whether satisfaction changed significantly over time
- Identify areas for improvement in order to increase satisfaction in the future
- Demographics

Survey Specs

- Interview length 6 minutes on average
- Survey fielding: September 5-28, 2023
- Sample source: Liberty customer list
- 1,516 customers participated, 1147 via an online survey and 369 via phone interviews
- The margin of error is plus or minus 2.5% at the 95% level for results based on all customers



Key Findings

Key Findings

- **Overall satisfaction dropped another 10 points this year, to 53%**. Satisfaction is 66% if customers specifically exclude cost.
  - ✓ Although cost is still the top complaint mentioned by dissatisfied customers, ***mentions of billing issues have more than tripled over the past year.***
  - ✓ Lack of problems, reliability and good service overall are mentioned the most by satisfied customers, although one-third of these customers also complain about cost.

- **Last year, Liberty's ratings were hit most on price-related issues, while this year satisfaction with bill and statement accuracy and customer service took the largest tumbles.**
  - ✓ In addition to bill/statement accuracy and customer service, there were very large declines for several reputational attributes – quality of services and building confidence in how it operates.
  - ✓ The largest decline over the past two years has been for providing good value for the price, from 71% to 30%.
  - ✓ Satisfaction ratings for most attributes are now lower than they were in 2014-2015.
  - ✓ The groups which consistently give Liberty lower satisfaction ratings are customers younger than 45 and more affluent customers (those living in households with annual incomes of $100,000 or more),

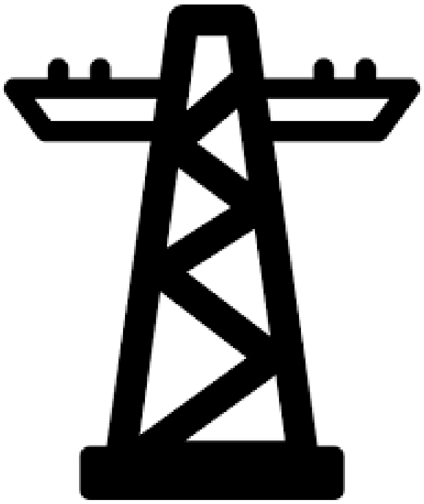
- **The most important drivers of satisfaction for Liberty**, and the areas which are most important to focus on, are:
  - ✓ Price
  - ✓ Bill/statement accuracy (improvement here will likely also improve perceptions about value for the price)
  - ✓ Customer service (improvement here will likely also improve perceptions about value for the price)

- **Looking at the open-ends, many customers had specific complaints about billing problems and difficulty getting into touch with Liberty.**

Key Findings

- **The percentage of customers contacting the company reached its highest level ever this year (81%)**.
    - ✓ Usage of the website has doubled since 2020 and currently more customers use it than call and speak with a Liberty representative.
    - ✓ Satisfaction remains much higher for contacts involving speaking with a Liberty representative than for the website.

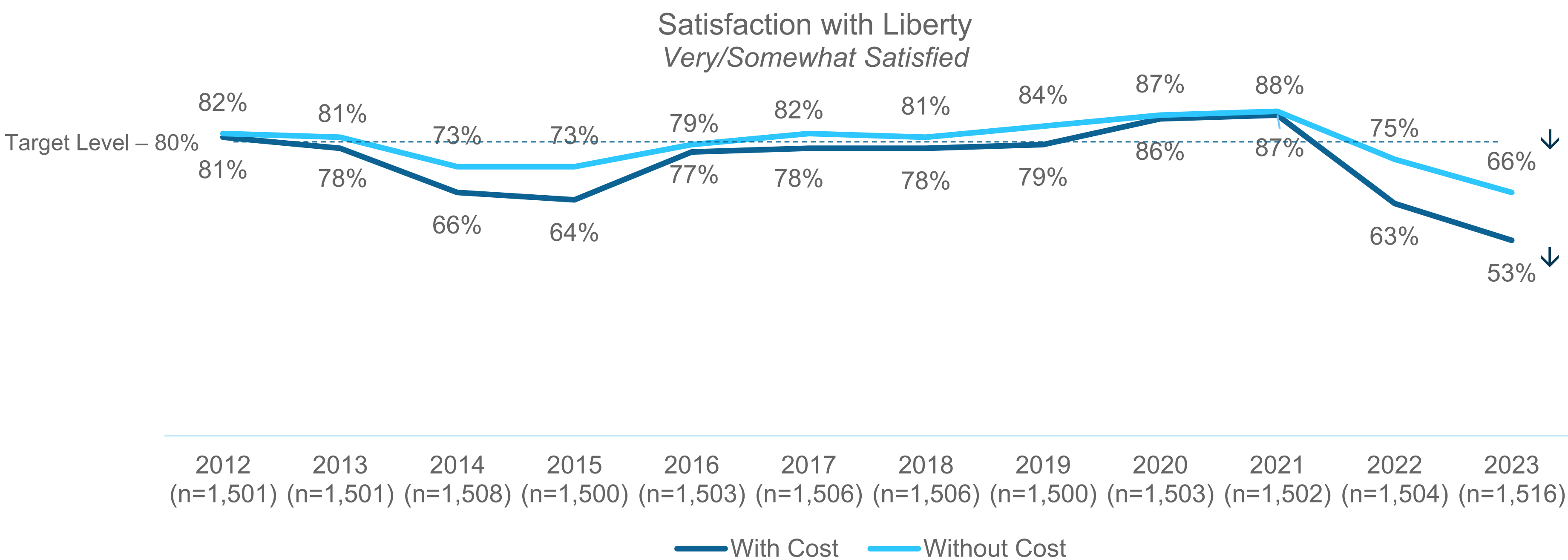
- **Awareness of Liberty's energy efficiency programs bumped up this year, to 57%.**
    - ✓ Aside from 2022, awareness of these programs has remained very stable, between 55% and 58%.
    - ✓ Increasing awareness of these programs is one way to tackle several issues for Liberty – helping customers reduce cost and being more community-minded.
    - ✓ Awareness of these programs has been shifting from direct mail to electronic sources, although mail remains the single strongest source, particularly among seniors. Aside from direct mail, email and the website are the biggest drivers of awareness.



Overall Satisfaction

Overall Satisfaction and Satisfaction without Cost

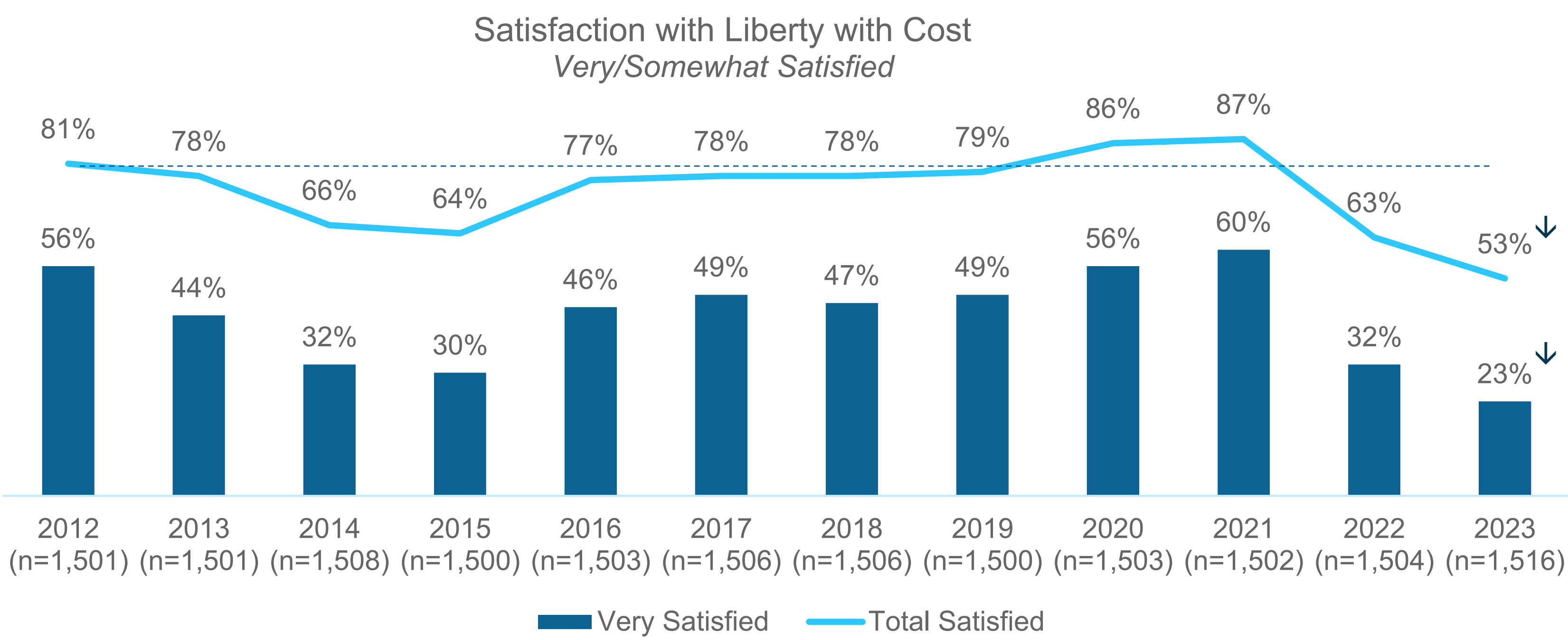
- Overall satisfaction with Liberty declined another 10 points this year, to 53%. Excluding cost, satisfaction declined by 9 points, to 66%. The 13-point gap in satisfaction between overall satisfaction and satisfaction excluding cost confirms the impact cost is having; in 2021, the gap was only a single percentage point.
- This year's results are lower than those from 2014-2015.



↑/↓ Indicates score is significantly higher/lower than 2022
Q3 Overall, how satisfied are you with Liberty?
QEASTO1 Using a scale where 5 is "very satisfied" and 1 is "very dissatisfied", how satisfied are you with the services, excluding price, that you are receiving from Liberty?

Overall Satisfaction

- Overall satisfaction dropped to 53% in 2023, driven by a 9-point decline in the percentage 'very satisfied' with Liberty.
- While the decline in satisfaction has occurred across the board, customers 65 and older remain the strongest group for Liberty.



2023 Satisfaction by Age

	Very	Total
<45	16%	40%
45-64	21%	51%
65+	28%	62%

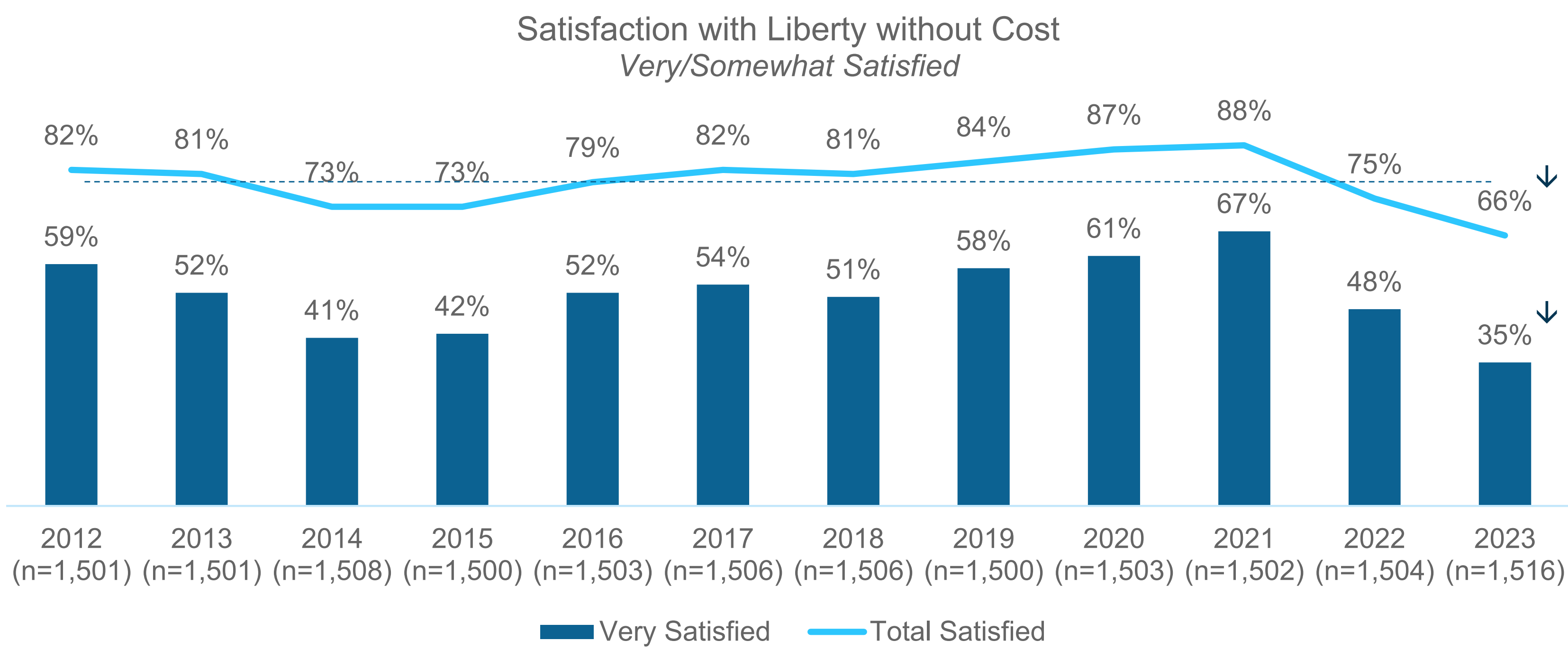
Liberty™

↑/↓	*Indicates score is significantly higher/lower than 2022*
Bases:	*<45 years of age (n=343), 45-64 years of age (n=576), 65+ years of age (n=597)*
Q3	*Overall, how satisfied are you with Liberty?*

LUTH research

Satisfaction Excluding Cost

- There has been less variability in satisfaction for Liberty excluding cost, although there was a major decline in satisfaction here as well in 2023, to 66%. The percentage 'very satisfied' with Liberty excluding cost has almost been cut in half since 2021.
- Mirroring overall satisfaction results, customers 65 and older give Liberty its highest satisfaction levels.



2023 Satisfaction by Age		
	Very	Total
<45	24%	59%
45-64	34%	65%
65+	43%	72%

↑/↓ *Indicates score is significantly higher/lower than 2022*
Bases: *<45 years of age (n=343), 45-64 years of age (n=576), 65+ years of age (n=597)*
QEASTO1 *Using a scale where 5 is "very satisfied" and 1 is "very dissatisfied", how satisfied are you with the services, excluding price, that you are receiving from Liberty?*

Reasons for Satisfaction or Dissatisfaction

- The main reasons customers are satisfied with Liberty are lack of problems, reliability and good service overall; however, almost one in three satisfied customers also complain about cost.
- Cost is overwhelmingly top complaint of dissatisfied customers, although billing problems are mentioned far more often this year than in 2022.

Total Satisfied (n=800)	Very Satisfied (n=347)	Neither Satisfied Nor Dissatisfied (n=203)	Total Dissatisfied (n=513)
Cost is too high (31%)	Never had a problem (29%)	Cost is too high (46%)	Cost is too high (59%)
Reliable service (19%)	Reliable service (27%)	Billing problems (19%)	Billing problems (38%)
Service good overall (16%)	Service good overall (21%)	Don't know much about them (10%)	Website problems (14%)
Never had a problem (16%)	Good customer service (14%)	Reliable service (8%)	Poor communication/unable to contact (14%)
Billing problems (9%)	Prompt repair service (14%)	Website problems (8%)	Poor customer service (10%)
Good customer service (8%)	Cost is reasonable (8%)	Adequate service (6%)	Liberty is dishonest (6%)
Prompt repair service (7%)	Cost is too high (7%)	Poor communication/unable to contact (5%)	

NOTE: Only reasons mentioned by at least 5% shown
Q3b Being as specific as possible, why did you say you are satisfied/dissatisfied with Liberty?

Reasons for Satisfaction

When I have an issue, they are able to resolve it simply. It was usually a paperwork issue or an issue with the new system that they installed. Nothing more.

A real person answers my call. When I needed protection on the wire to my house for the roofers and siding workers, they were there quickly as promised.

I find them very reliable. They came within an hour when the power was out and worked until it was restored. The ease of setting up an account was evident and easy to link to an existing account.

When we lost electricity, they had a team at our home to repair the problem even though it was Thanksgiving Day.

It's been reliable the 12 years I've lived here. One time we lost power, and the crews were there in a less than 2 hours. They found everything in order with the connection to the house. I asked the tech to come and look at the fuse box. For some reason the master switch is what blew. That's never happened before or since. Most likely it was due to a new microwave oven we purchased. I would not have figured that out alone.

Because I owe back electric, and they are very understanding and helpful in getting me into a plan, so I don't lose my electricity.

I love the consistent and reliable service especially when there is severe weather the linemen are on top of their game.

Once I smelled a weird odor and panicked. The customer service gal sent a tech to my home immediately.

I was encouraged by Liberty to part with my ancient chest freezer and my electricity usage (and bill) plummeted. Liberty has always restored power quickly when there has been an outage. The Utility Arborist who came last week to assess a potentially hazardous large sugar maple near the power lines and the road seemed quite knowledgeable and was also very pleasant.

Reasons for Dissatisfaction

I have not received a paper statement in months. I also have not received an emailed bill. Then they shut off my power unannounced to me. They stated they mailed out a warning, but I never got it. I pay my bills and have been a client for 16 years. I have never had my power shut off.

Communication is virtually impossible. Phone contact impossible; local walk-in center closed; attempt to pay via Walmart (as suggested by Liberty employee) failed. Overall impression is that Liberty does not wish to be bothered by customers.

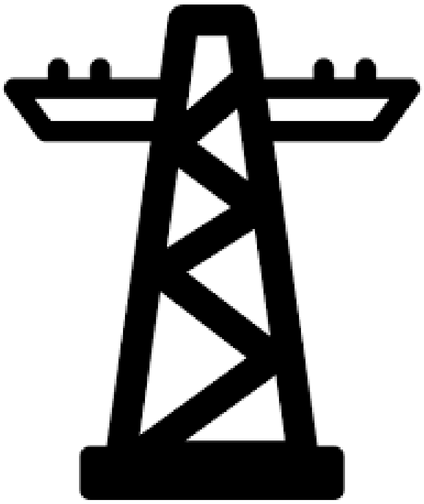
Billing issues, poor website and mobile app experience, issues with automated payments, ongoing problems logging into their website, difficulties contacting customer service to remedy the above problems.

Billing issues, poor website and mobile app experience, issues with automated payments, ongoing problems logging into their website, difficulties contacting customer service to remedy the above problems.

Your auto billing system has not worked for over a year since you changed your website. ***I've never seen a company so opposed to receiving money for services****.*

Ever since Liberty switched over to their new system, they've tanked IMO! They can't get their train on track with billing, and somehow my Walmart is now having issues with receiving payments; I find out they're not even listed as a Western Union recipient, so my bill payments take many, many days to get to their final destination; NOT ACCEPTABLE! Also, there's NO option to set up my credit card for auto pay, and paying over the phone has a $1.75 fee; NOT ACCEPTABLE!

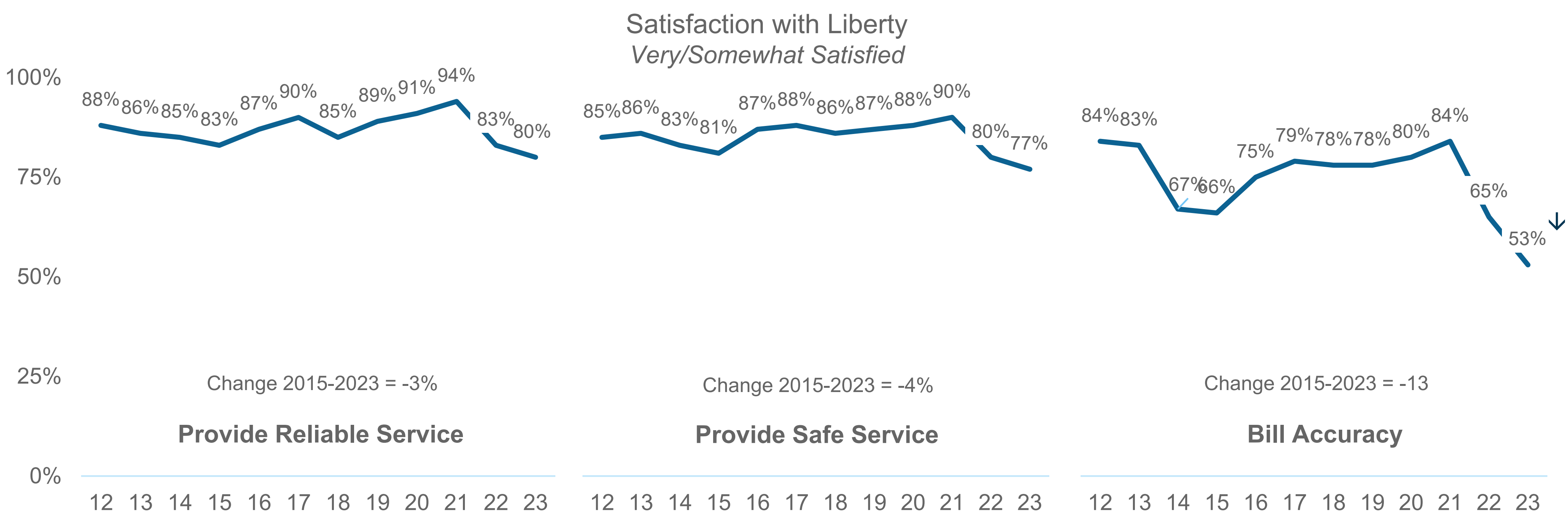
1. One must provide an account number to report an outage. 2. Cannot pay bill using credit card. 3. Website often crashes. 4. Cannot review prior monthly statements. 5. Electricity rates for delivery are exorbitant.



Key Indicators and Company Evaluations

Key Indicators

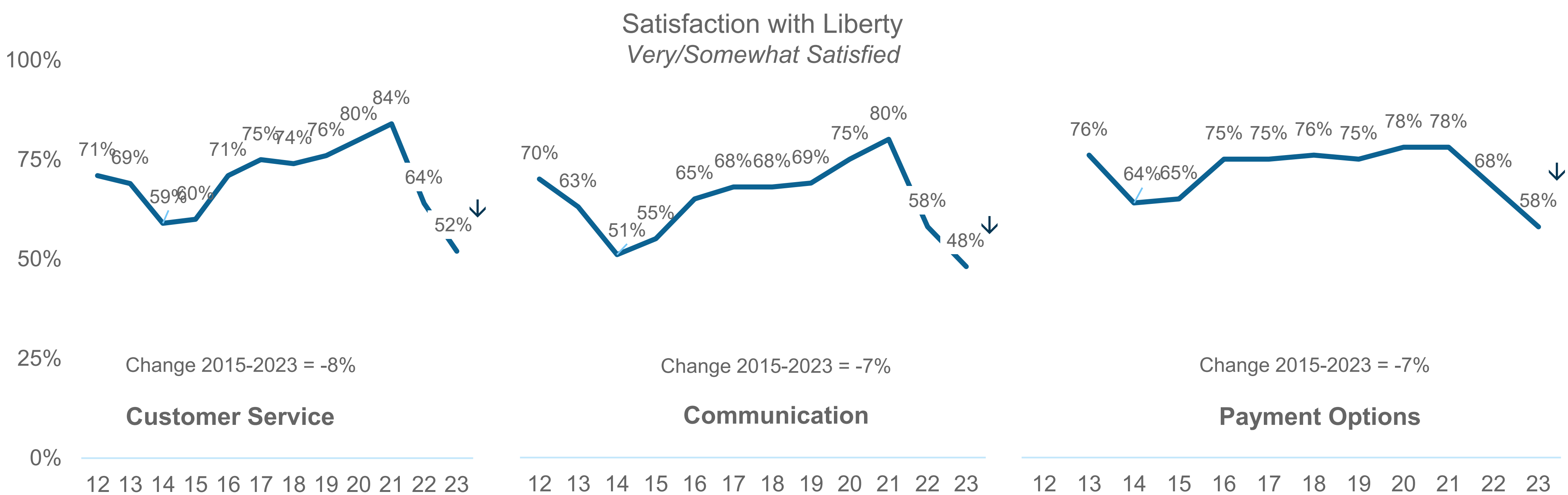
- Ratings this year held up best for providing safe and reliable services, the core responsibilities for a utility.
- Satisfaction with bill accuracy dropped by 12 points this year, which is tied with customer service for the largest decline in 2023.



↑/↓ *Indicates score is significantly higher/lower than 2022*
Base: *Varies by indictor and by year*
Q2. *Please rate Liberty in the following areas by using a 5-point scale with 5 being "Very Satisfied" and 1 being "Very Dissatisfied".*

Key Indicators

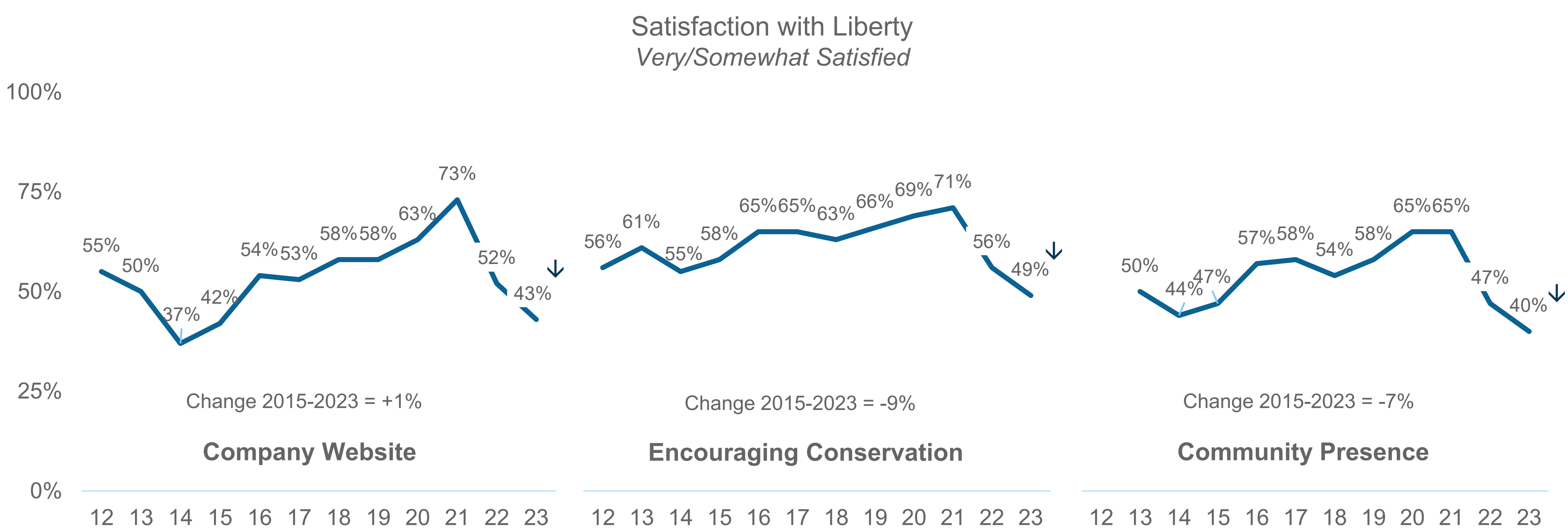
- Liberty's rating for customer service declined by 12 points this year, together with bill accuracy the largest drops in 2023.
- There were also significant satisfaction declines for communication and payment options.
- Satisfaction with all of these Key Indicators is well below where it was in 2015.



↑/↓ *Indicates score is significantly higher/lower than 2022*
Base: *Varies by indictor and by year*
Q2. *Please rate Liberty in the following areas by using a 5-point scale with 5 being "Very Satisfied" and 1 being "Very Dissatisfied".*

Key Indicators

- Satisfaction levels declined significantly this year for the website, encouraging conservation, and community presence. Aside from cost, community presence is where Liberty is rated lowest.
- Compared with the 2014-2015 trough, ratings have held up best for the website.



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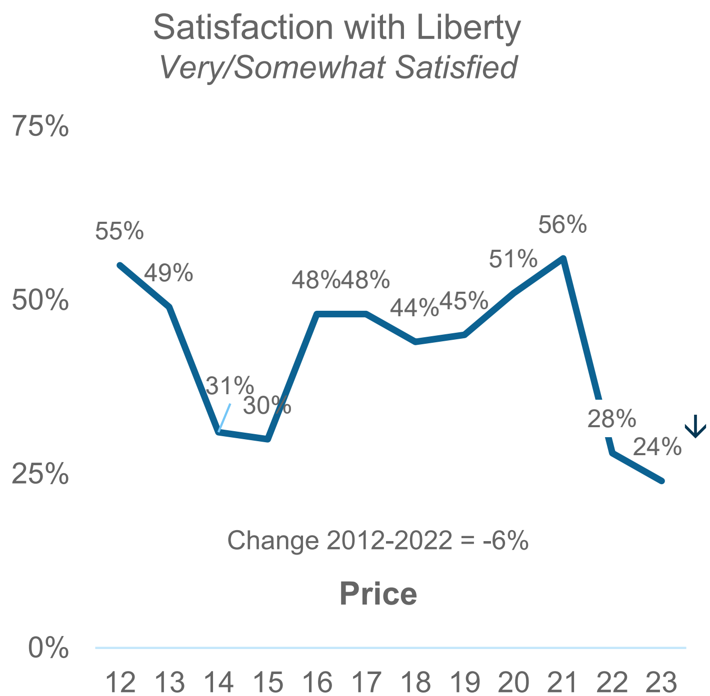
↑/↓ *Indicates score is significantly higher/lower than 2022*
Base: *Varies by indictor and by year*
Q2. *Please rate Liberty in the following areas by using a 5-point scale with 5 being "Very Satisfied" and 1 being "Very Dissatisfied".*

LUTH research

Key Indicators

- Satisfaction with price slipped another 4 points this year, to 24%.
- Satisfaction is below where it was in 2015, at the end of the last major decline in Liberty satisfaction.



Liberty™

↑/↓	*Indicates score is significantly higher/lower than 2022*
Base:	*Varies by indictor and by year*
Q2.	*Please rate Liberty in the following areas by using a 5-point scale with 5 being "Very Satisfied" and 1 being "Very Dissatisfied".*

LUTH research

Key Indicators

- Across the board, satisfaction levels are lowest for customers younger than 45. The largest satisfaction gaps between customers younger than 45 and those 65 and older are for bill/statement accuracy and encouraging electricity conservation (both 17 points).
- Aside from providing reliable and safe electricity, satisfaction levels are lower among customers living in households earning more than $100,000 annually; the gap between satisfaction between the highest and lowest income groups is largest for community presence (19 points) and customer satisfaction (18 points).

Very/Somewhat Satisfied	Total	Age 18-44	Age 45-64	Age 65+	Household Income <$50K	Household Income $50K-<$100K	Household Income $100K+
Providing reliable electricity	80%	77%	77%	84%	79%	81%	81%
Providing safe electricity	77%	71%	75%	82%	79%	77%	76%
Payment options	58%	49%	58%	63%	61%	62%	56%
Accuracy of bill/statement	53%	43%	50%	60%	54%	58%	47%
Customer service	52%	47%	51%	56%	61%	56%	43%
Encouraging electricity conservation	49%	39%	47%	56%	57%	54%	41%
Communications	48%	42%	46%	54%	57%	54%	41%
Company website	43%	40%	45%	44%	53%	51%	37%
Community presence	40%	33%	39%	44%	47%	49%	28%
Price	24%	22%	24%	26%	33%	27%	17%
Average	***52%***	***47%***	***51%***	***57%***	***58%***	***57%***	***47%***

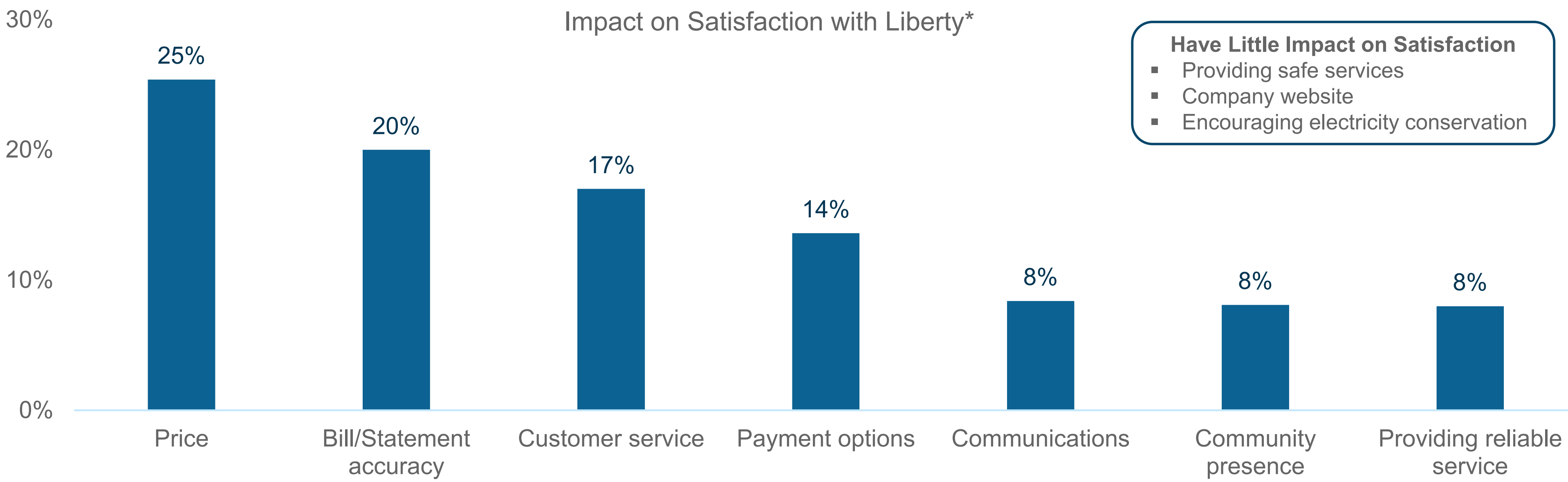
Liberty™

Base: Varies by indictor and subgroup
Q2. Please rate Liberty in the following areas by using a 5-point scale with 5 being "Very Satisfied" and 1 being "Very Dissatisfied".

LUTH research

Drivers of Satisfaction

- A regression analysis was conducted to help quantify the impact of the Key Indicators on overall satisfaction with Liberty. The results for the attributes which had a significant impact on satisfaction are shown below.
- The indicators which have the biggest impact on satisfaction with Liberty are price, bill and statement accuracy and customer service; these account for 62% of the variation in satisfaction with Liberty. Compared with last year, the importance of bill and statement accuracy increased.



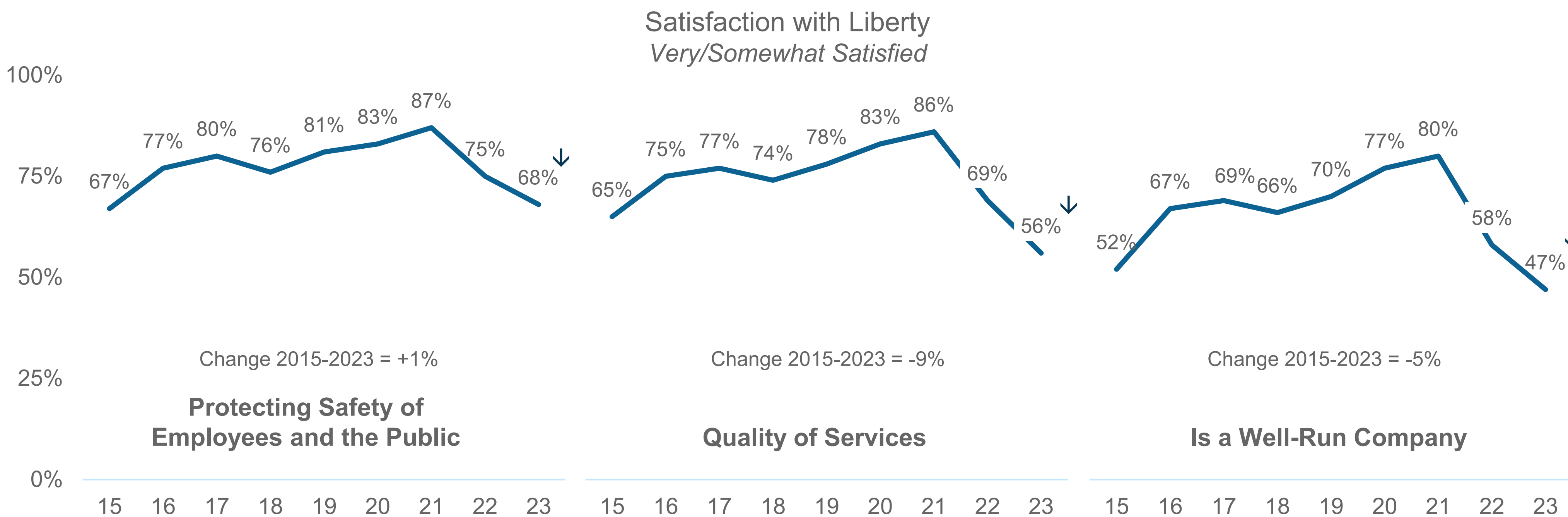
Have Little Impact on Satisfaction
- Providing safe services
- Company website
- Encouraging electricity conservation

Liberty™ **Based on standardized regression coefficients*

LUTH research

Company Evaluations

- Mirroring the results for Key Indicators, satisfaction with all Company Evaluations also declined this year.
- Satisfaction with Liberty protecting safety and service quality remains the highest of all Company Evaluations.
- Quality of services is the Evaluation with the largest decline in satisfaction this year (13 points).



↑/↓ *Indicates score is significantly higher/lower than 2022*
Base: *Varies by indictor and by year*
Q5. *Based on a 5-point scale where 5 means "Excellent" and 1 means "Poor", please rate how good a job Liberty does on each of the following items:*

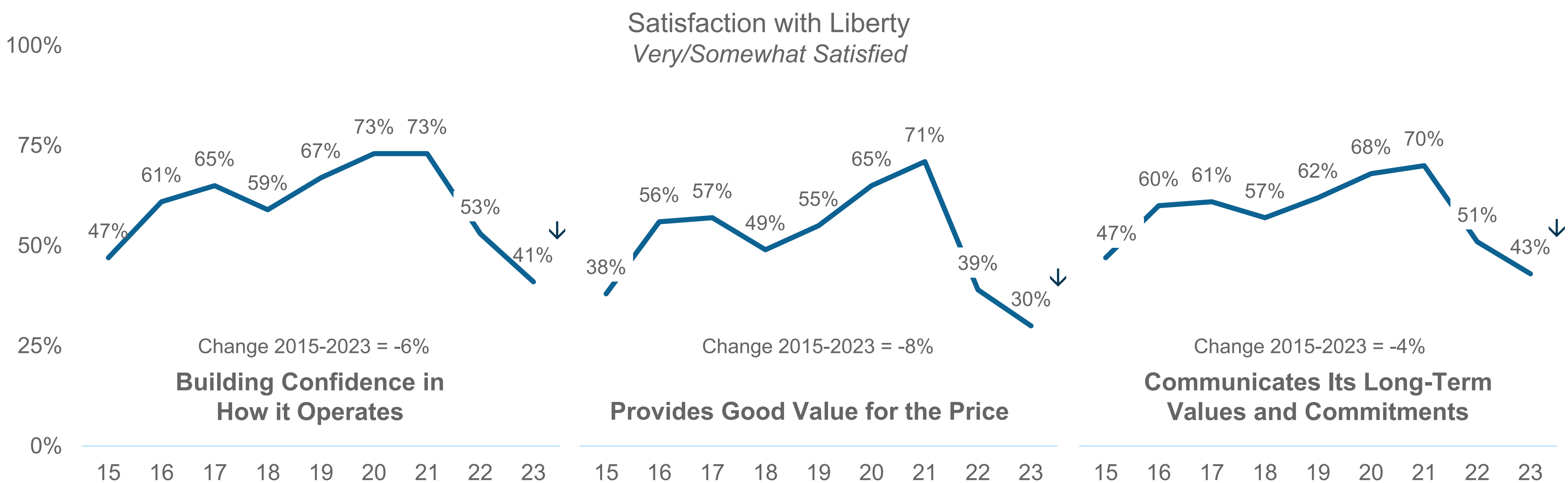
Company Evaluations

- Satisfaction with Liberty being environmentally responsible, a responsible corporate citizen, and having a commitment to the local community all significantly declined this year, although the declines were of much less magnitude than in 2022.
- For these three Evaluations, satisfaction levels are close to where they were in 2015.

↑/↓	*Indicates score is significantly higher/lower than 2022*
Base:	*Varies by indictor and by year*
Q5.	*Based on a 5-point scale where 5 means "Excellent" and 1 means "Poor", please rate how good a job Liberty does on each of the following items:*

Company Evaluations

- Liberty's rating for providing good value for the price declined by another 9 points this year, to 30%; this is the Evaluation with the largest total decline since 2021 (-41 points).
- Satisfaction levels also dropped in 2023 for Liberty building confidence in how it operates (-12 points) and communicating long-term values and commitments (-8).



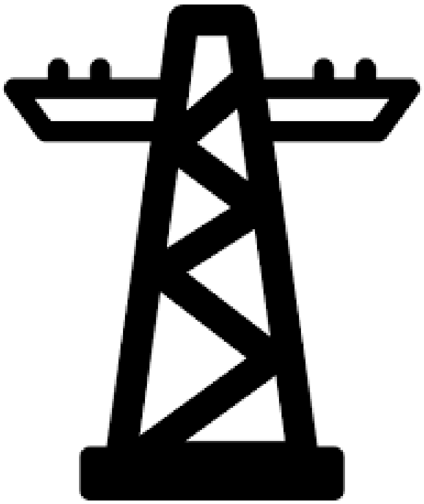
↑/↓ *Indicates score is significantly higher/lower than 2022*
Base: Varies by indictor and by year
Q5. Based on a 5-point scale where 5 means "Excellent" and 1 means "Poor", please rate how good a job Liberty does on each of the following items:

Company Evaluations

- Across the board, satisfaction for Liberty is highest among customers 65 and older, although the company's rating for providing good value for the price is notably lower among this group.
- Satisfaction levels are also lower among the most affluent customers, with the largest gaps for Liberty being a well-run company and building trust in how it operates. Lower satisfaction levels among more affluent customers have been common since tracking began.

		Age			Household Income		
Very/Somewhat Satisfied	Total	18-44	45-64	65+	<$50K	$50K-<$100K	$100K+
Protecting the safety of employees and the public	68%	59%	67%	74%	74%	68%	65%
Quality of services provided to customers	56%	47%	52%	66%	64%	58%	50%
Operating in an environmentally responsible manner	56%	49%	55%	62%	64%	59%	46%
Being a responsible corporate citizen	48%	41%	46%	55%	57%	53%	38%
Commitment to the local community	47%	39%	47%	54%	57%	53%	35%
Being a well-run company	47%	40%	45%	53%	59%	52%	33%
Communicates its values and long-term commitments	43%	40%	40%	49%	53%	47%	34%
Building customer confidence and trust in how it operates	41%	35%	39%	48%	52%	48%	29%
Providing good value for the price	30%	24%	29%	34%	38%	33%	20%
Average	***49%***	***41%***	***47%***	***55%***	***58%***	***52%***	***39%***

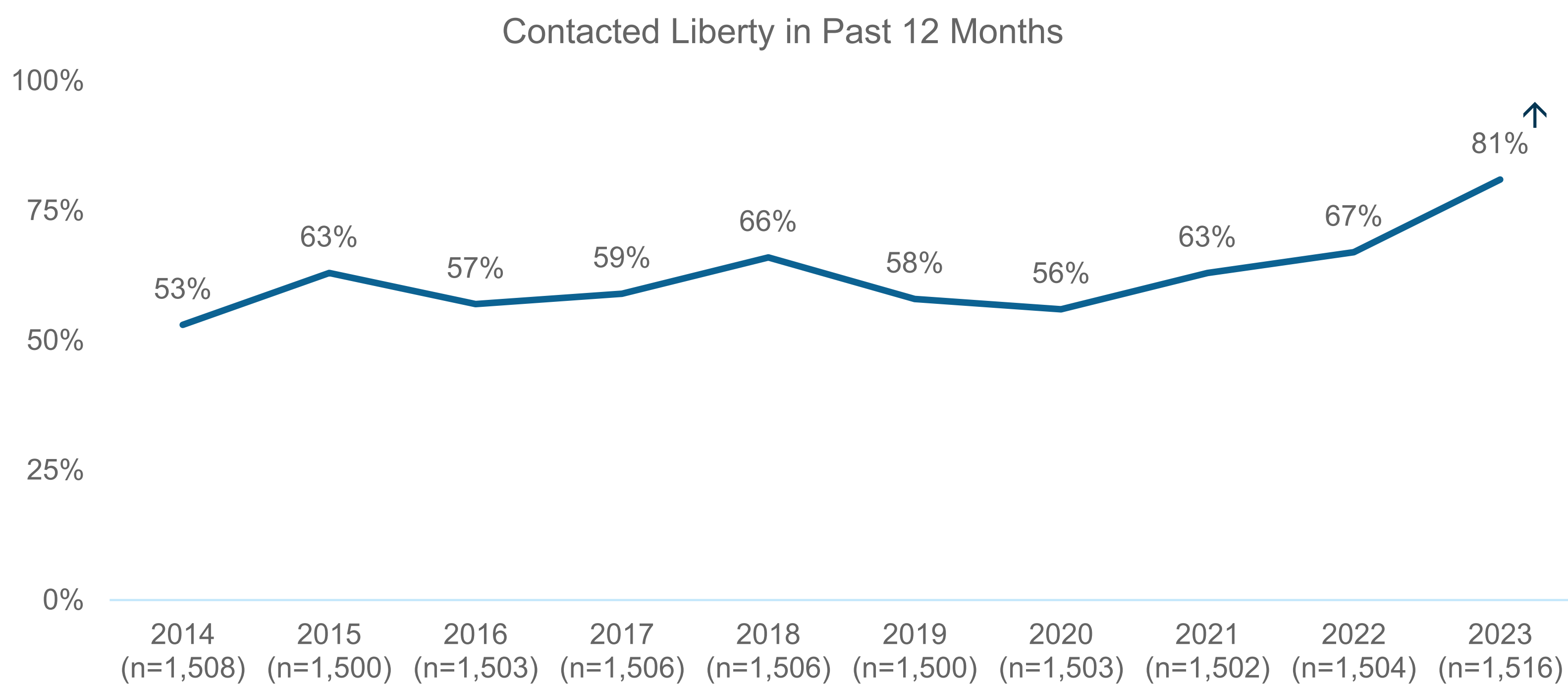
Base: Varies by indictor
Q2. Please rate Liberty in the following areas by using a 5-point scale with 5 being "Very Satisfied" and 1 being "Very Dissatisfied".



Contacting Liberty

Contacting Customer Service

- Four in five Liberty customers contacted the company in the past year, a significant increase since 2022 and the highest contact level measured since tracking began.
- A large majority of customers in all age groups contacted Liberty, with those younger than 45 being the most likely to do so.

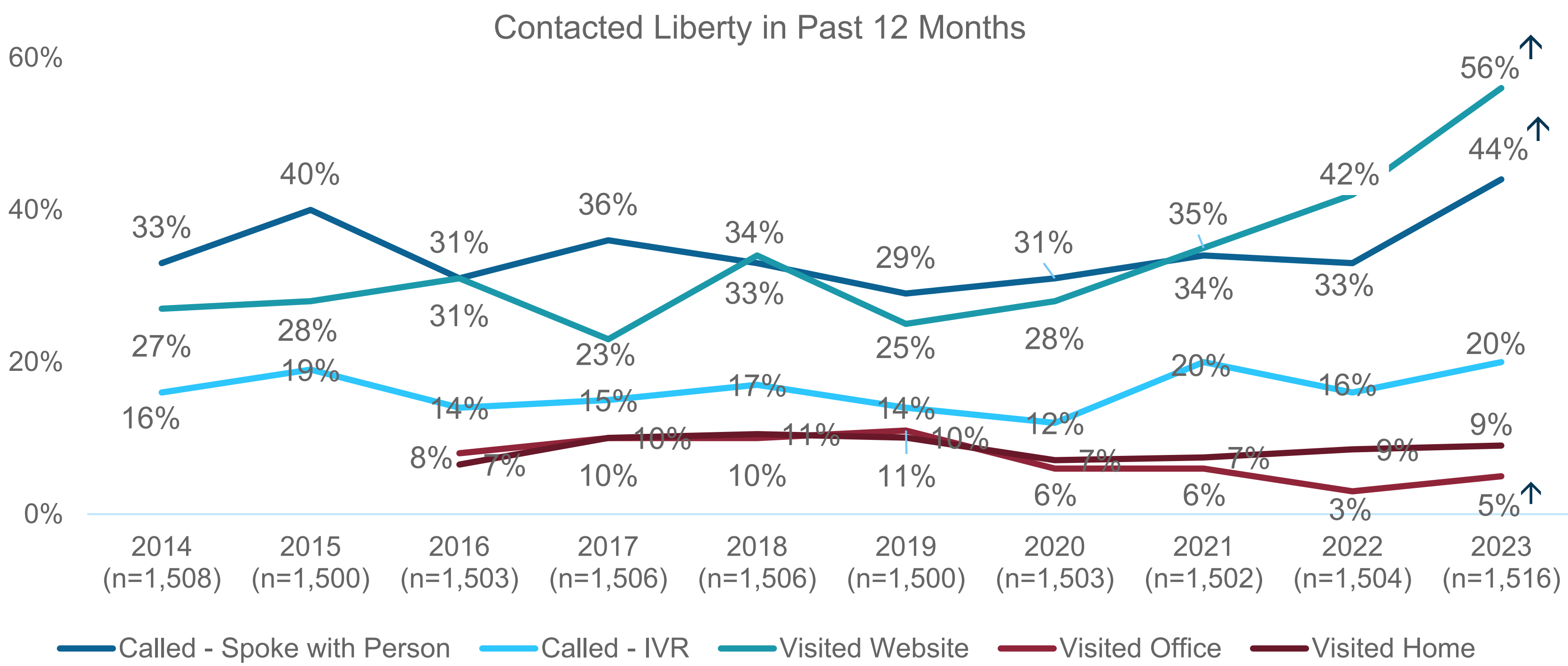


2023 Contact by Age	
<45	87%
45-64	83%
65+	75%

↑/↓ Indicates score is significantly higher/lower than 2022
Bases: <45 years of age (n=343), 45-64 years of age (n=576), 65+ years of age (n=597)
Q6z Which of the following have you done in the past year? Please select all that apply.

Contacting Customer Service

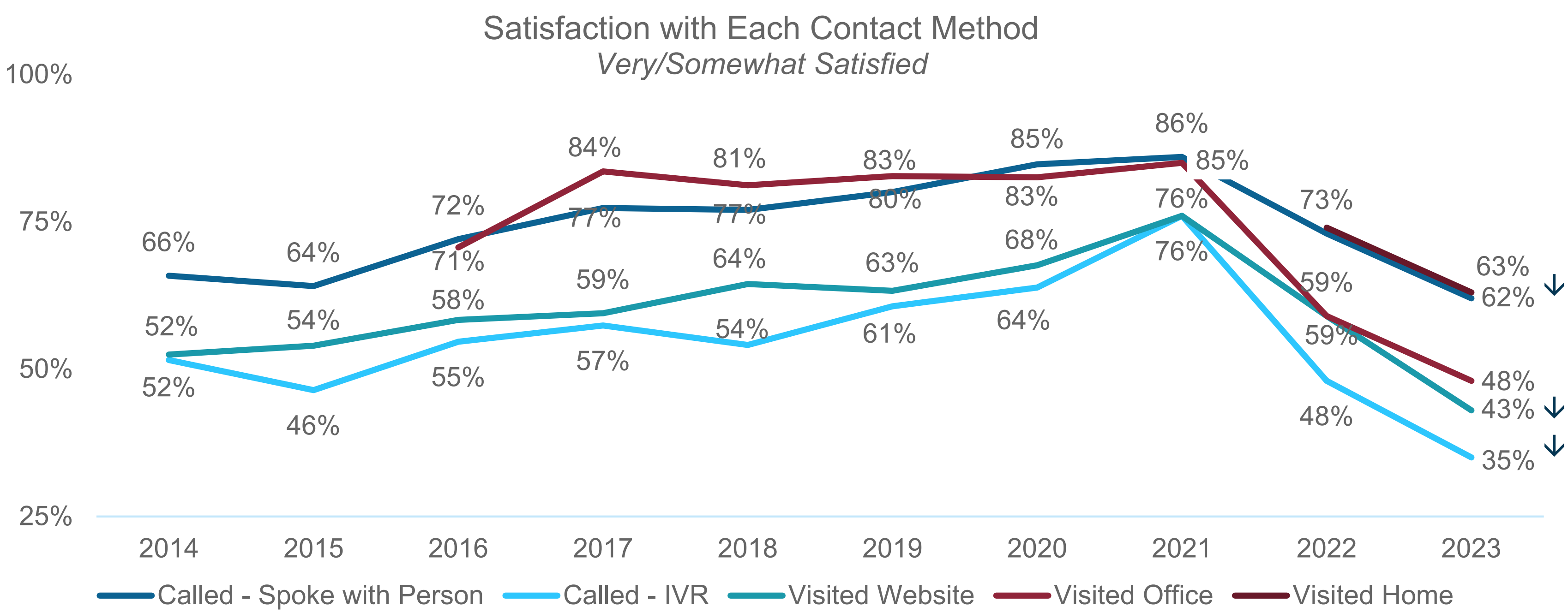
- The most common ways customers contact Liberty are by visiting the website and calling and speaking with a representative. Usage of the website for customer service has doubled since 2020.



↑/↓ *Indicates score is significantly higher/lower than 2022*
Q6z *Which of the following have you done in the past year? Please select all that apply.*
Q6x *When you called Liberty in the past year, did you…?*

Satisfaction with Contact Method

- Satisfaction levels for three of the five types of contact dropped significantly this year – calling and speaking with a person, visiting the website and calling and using IVR.
- Satisfaction remains highest for home visitation and calling and speaking with a Liberty representative.

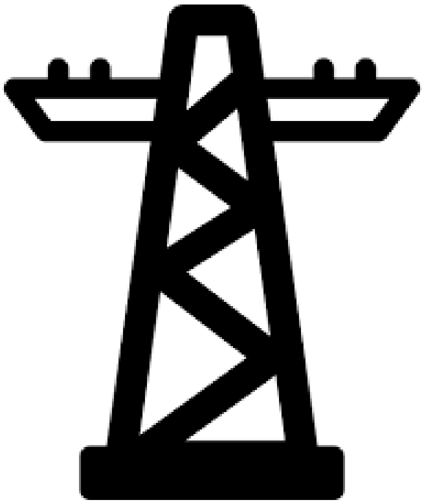


↑/↓ *Indicates score is significantly higher/lower than 2022*

Base: Varies by contact method and year

Q6y Overall, how satisfied are you with your experience with each of the following?

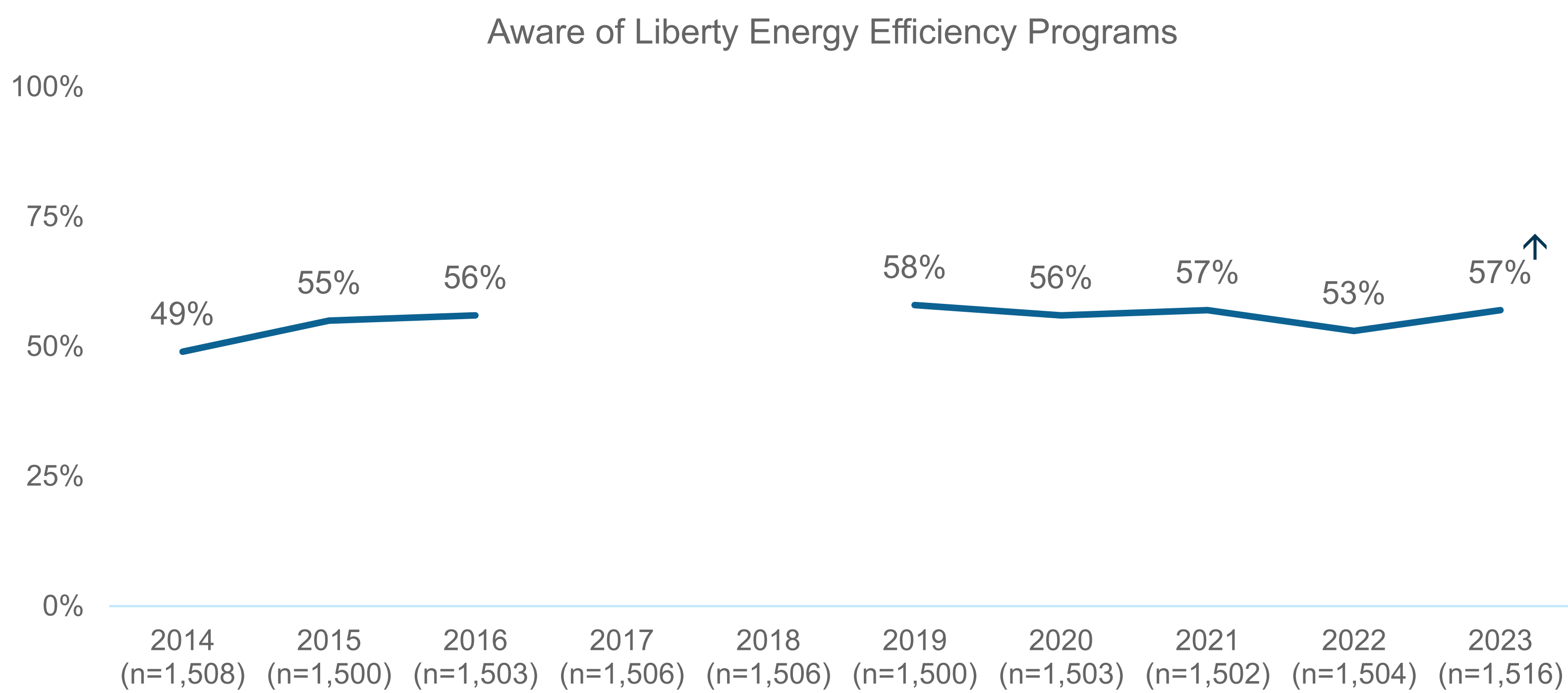
LUTH research



Energy Efficiency Programs

Awareness of Energy Efficiency Programs

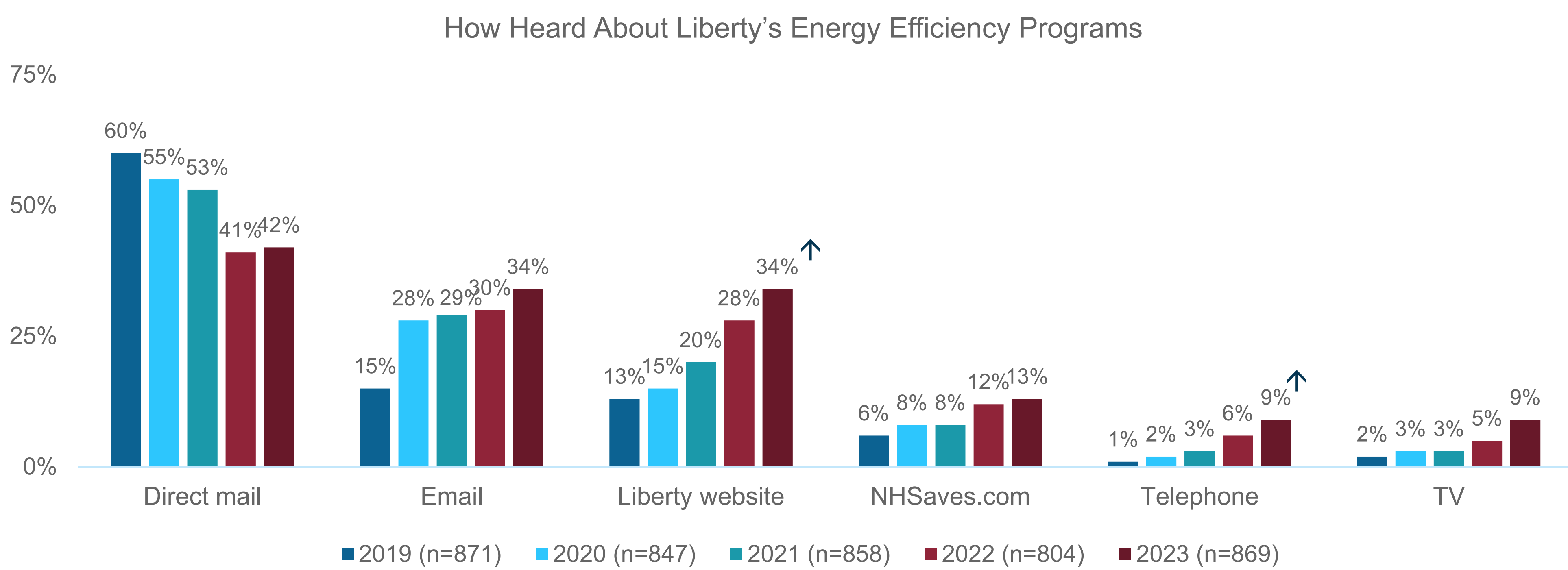
- Awareness of Liberty energy efficiency programs bumped up this year, to 57%.
- Since 2015, awareness has remained very stable, between 55% and 58%, aside from 2022.



QEAST06 Are you aware that Liberty offers energy efficiency programs to help you reduce your energy costs?

Source of Awareness

- Awareness of Liberty energy efficiency programs has been shifting from direct mail to electronic sources, although mail remains the single strongest source (especially among customers 65 and older). One-third of customers aware of Liberty energy efficiency programs heard about them via email or the website.



↑/↓ *Indicates score is significantly higher/lower than 2022*

QEAST16. *How did you hear about Liberty's energy efficiency programs?*

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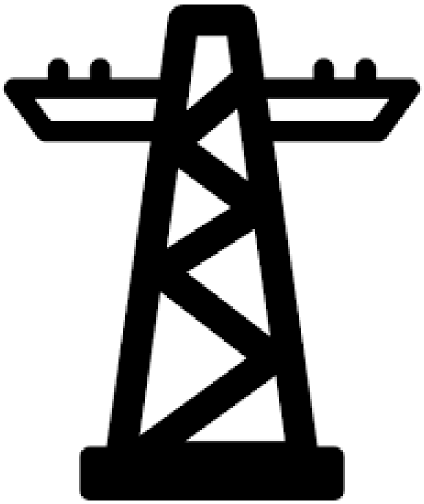

Appendix

Demographics

	2015	2016	2017	2018	2019	2020	2021	2022	2023
	n=1500	n=1503	n=1506	n=1506	n=1500	n=1503	n=1502	n=1504	n=1516
Gender									
Male	45%	46%	46%	50%	51%	50%	50%	49%	48%
Female	55%	54%	54%	50%	49%	50%	49%	49%	50%
Age									
18-34	11%	15%	11%	8%	5%	10%	14%	9%	8%
35-44	11%	13%	11%	12%	8%	13%	18%	17%	15%
45-54	18%	15%	17%	15%	14%	15%	16%	18%	15%↓
55-64	24%	23%	23%	26%	27%	21%	19%	22%	23%
65+	37%	33%	38%	40%	45%	41%	34%	33%	39%↑
Household Income									
<$50,000	31%	22%	28%	21%	25%	21%	22%	18%	16%
$50,000-$74,999	14%	17%	16%	14%	15%	17%	16%	16%	15%
$75,000-$99,999	11%	10%	10%	13%	12%	13%	15%	14%	14%
$100,000+	16%	20%	14%	22%	19%	17%	19%	25%	26%
Prefer not to say	28%	31%	28%	30%	29%	32%	28%	26%	29%

Liberty™ ↑/↓ *Indicates score is significantly higher/lower than 2022*

ETH research

Demographics

	2015	2016	2017	2018	2019	2020	2021	2022	2023
	n=1500	n=1503	n=1506	n=1506	n=1500	n=1503	n=1502	n=1504	n=1516
Ethnicity									
White/Caucasian	86%	85%	85%	83%	83%	83%	80%	79%	80%
Other ethnicities	8%	7%	6%	8%	7%	8%	10%	9%	8%
Prefer not to say	8%	8%	9%	9%	10%	9%	10%	12%	12%
Educational Level									
High school or less	22%	18%	23%	17%	21%	16%	17%	21%	18%
Some college	26%	26%	29%	30%	30%	27%	29%	27%	22% ↓
College graduate	21%	23%	17%	20%	20%	22%	21%	20%	23%
Graduate school	25%	27%	24%	27%	23%	26%	25%	23%	28% ↑
Prefer not to say	7%	6%	7%	6%	6%	9%	8%	9%	9%
Children in Household									
Children under 18	21%	23%	19%	23%	17%	21%	28%	32%	26% ↓

↑/↓ *Indicates score is significantly higher/lower than 2022*

Demographics

	2015	2016	2017	2018	2019	2020	2021	2022	2023
	n=1500	n=1503	n=1506	n=1506	n=1500	n=1503	n=1502	n=1504	n=1516
Own or Rent Home									
Own	79%	73%	77%	83%	81%	76%	71%	78%	80%
Rent	20%	26%	21%	16%	18%	22%	27%	20%	19%
Prefer not to say	1%	1%	2%	1%	1%	2%	2%	2%	1%
Type of Home									
Single-family	79%	76%	77%	82%	79%	76%	73%	80%	81%
Multi-family	19%	21%	20%	16%	17%	20%	23%	16%	16%
Other/Don't know	2%	3%	3%	2%	4%	4%	4%	4%	3%

Liberty™ ↑/↓ *Indicates score is significantly higher/lower than 2022*

LUTH research

1983 MASS. PUC LEXIS 5

Massachusetts Department of Public Utilities

April 29, 1983

D.P.U. 1300

MA Department of Public Utilities ***Decisions***

Reporter
1983 MASS. PUC LEXIS 5 *

Re Western Massachusetts Electric Company ; Intervenors: Coalition of Western Massachusetts Governments and Institutions, Franklin Community Action Corporation, Berkshire Community Action Council, Hampshire Community Action Committee, Valley Opportunity Council, Monsanto Company, Mead Corporation, Kimberly Clark Corporation, and Executive Office of Energy Resources

Core Terms

company, cost, was, percent, has, customer, fuel, calculate, test-year, electric, intervenor, coalition, energy, attorney general, dividend, payroll, ratio, inflate, transmission, working capital, estimate, residual, months, cost of services, cost-of-service, rate base, interim, plant, premium, pension

Counsel

[*1] APPEARANCES: Robert S. Cummings, Robert S. Cummings, P. C., Maurice L. Zilber, Maurice L. Zilber, P. C., Robert L. Dewees, Jr., and Peggy A. Nelson, Boston, for Western Massachusetts Electric Company, petitioner; Francis X. Bellotti, attorney general, by James L. Lewis, Stephen P. Bowen, and George B. Dean, assistant attorneys general, Boston, for the department of the attorney general, David Silverstone, Hartford, Connecticut, for Coalition of Western Massachusetts Governments and Institutions, Charles Harak, Boston, for Franklin Community Action Corporation, Berkshire Community Action Council, Hampshire Community Action Committee, and Valley Opportunity Council, Andrew J. Newman, Guterman, Horvitz, Rubin & Rudman, Boston, for Monsanto Company and Mead Corporation, Kenneth A. Strassner, Arlington, Virginia, for Kimberly-Clark Corporation, Robert G. Grassi, Boston, for Executive Office of Energy Resources, intervenors.

Panel: Before Levy, chairman, and McIntyre and Keegan, commissioners.

Opinion

By the DEPARTMENT:

I. *History of the Proceeding*

On October 15, 1982, Western Massachusetts Electric Company ("WMECo" or "company") filed with the department of public utilities ("department") tariff schedules of proposed rate changes under MDPU Nos. 466

through 475 to become effective **[*2]** November 1, 1982. The revised rates and charges were designed to increase the company's retail revenues by 524,063,000, or approximately 10.2 per cent, based upon a test period of twelve months ending June 30, 1982. [1] Contemporaneously with the filing for permanent rate relief, the company petitioned the department for interim relief in the amount of 55,310,000. Both petitions were docketed as D.P.U. 1300. On October 19, 1982, the department suspended the rates and charges until May 1, 1983, in order to allow further investigation into the propriety of the proposed increase.

The department last granted the company a rate increase in D.P.U. 957, issued May 28, 1982. In that order, which was based on a test year ending June 30, 1981, the department found that the company was entitled to a retail rate increase of $ 4,324,000. Upon recalculation, that amount was increased by $ 127,000 to $ 4,451,000. Re Western Massachusetts Electric Co. D.P.U. 957-A, July 28, 1982.

Several parties petitioned for leave to intervene in both the interim and permanent rate proceedings. Intervenor status was accorded Francis X. Bellotti, the attorney general of the commonwealth of Massachusetts ("attorney **[*3]** general"), the Coalition of Western Massachusetts Governments and Institutions ("coalition"), five community action programs in western Massachusetts ("FCAC"), the Monsanto Company ("Monsanto"), [2] the Kimberly-Clark Corporation ("Kimberly-Clark"), and the Executive Office of Energy Resources ("EOER"). [3] On February 10, 1983, a petition to intervene was filed by Trident Alloys, Inc., Atlas Founders, Inc., Hampden Fence Supply, Inc., Manufacturers Pattern and Foundry Corporation, and Western Bronze, Inc. ("petitioners"). Petitioners are all industrial and commercial customers of the company. By order dated February 17, 1983, the department denied the petition to intervene, but allowed petitioners to submit a brief on the rate design issues which were raised in the permanent proceeding. The commission designated Alycia K. Lyons as the hearing officer for the case.

Public hearings were held in Springfield on November 22, 1982, and in Pittsfield on January 20, 1983, to afford interested persons an opportunity to be heard on the company's proposed rates. Numerous customers of the company appeared at these hearings and expressed their concerns to the commission. An evidentiary hearing was **[*4]** held on the company's petition for interim rate relief on November 19, 1982. Evidentiary hearings on the company's permanent rate application commenced at the department on November 30, 1982, and concluded on March 14, 1983. In all, seventeen days of evidentiary hearings were held.

In support of its filing, the company presented five witnesses: Lawrence H. Shay, regional vice president and chief administrative officer of the company (company operations; customer service; conservation programs; construction program); E. James Ferland, executive vice president and chief financial officer of the company (WMECo's financial condition); Warren A. Hunt, vice president, revenue requirements (cost of service; capital structure); Joseph F. Brennan, president of Associated Utility Services, Inc. (cost of equity); and H. Edwin Overcast, manager of rate research of Northeast Utilities Service Company ("NUSCo") (rate design; cost allocation). Also, four persons were sworn and appeared before the department to assist the other witnesses in responding to cross-examination: John W. Noyes, director of revenue requirements preparation and analysis for NUSCo (assisted Mr. Hunt); Frank R. Locke, director **[*5]** of customer business services for NUSCo (assisted Mr. Shay); Peter H. Judd, a consultant to NUSCo's corporate and environmental planning department (assisted Mr. Shay); and A. Gerald Harris, vice president of Associated Utility Services, Inc. (assisted Mr. Brennan).

The coalition sponsored the testimony of Charles W. King, of Snavely, King and Associates, who addressed the issue of the appropriate cost of equity for the company. Monsanto and Kimberly-Clark sponsored three witnesses who testified on rate design: Michael L. Doyle, a plant electrical engineer from Monsanto Company, and Alan Rosenberg and Mark Drazen from Drazen-Brubaker & Associates, Inc.

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[1] This amount was revised downward by the company on April 15, 1983, to $ 21,372,000 in order to reflect certain revisions made to various adjustments during the course of the proceeding.

[2] On January 21, 1983, Monsanto amended its petition to include Mead Corporation.

[3] The EOER did not participate in the interim rate case.

On December 9, 1982, the attorney general filed a motion to dismiss. On December 17, 1982, the company moved to strike and expunge from the record the attorney general's motion. Kimberly-Clark and Monsanto also responded to the attorney general's motion on December 20, 1982. On December 23, 1982, the attorney general filed a motion for leave to amend his motion to dismiss, together with an amended motion to dismiss. The company filed answers to the attorney general's amended motion and to the response of Monsanto and Kimberly-Clark **[*6]** on January 4, 1983. By order dated January 24, 1983, the department denied both the attorney general's motion to dismiss and the requests set forth in the response of Kimberly-Clark and Monsanto. The department also dismissed the company's motion to strike and expunge.

On March 9, 1983, petitioners filed a motion to allow the filing of intervenor testimony, together with the testimony of C. William Galaska, president of Trident Alloys, Inc. That testimony was never admitted into the record in this proceeding, and on March 24, 1983, the company filed a motion to strike certain portions of petitioners' brief which refer to the testimony of Mr. Galaska. That motion is hereby allowed, and all references to the proposed testimony of Mr. Galaska are hereby stricken.

Pursuant to department practice, the record in this proceeding was left open to allow for the submission of certain updated information, including WMECo's most recent property tax bills and updated inflation data. By letter dated April 5, 1983, the attorney general requested that two notices issued by the Federal Energy Regulatory Commission ("FERC") concerning WMECo's capacity transactions be admitted into the record in **[*7]** this case as Into filed Exh AG-122. By letter dated April 14, 1983, the company contends that the exhibit is unnecessary since the record already reflects the capacity transactions that are the subject of the FERC notices. However, we find that the notices are properly includable in the record as a late filed exhibit. Accordingly, we hereby allow the admission of Exh AG-122.

The issues arising in this proceeding were briefed in several stages. The company filed its initial brief on its interim rate proposal on November 23, 1982. The attorney general, the coalition, and FCAC submitted briefs on this issue on November 30, 1982. The company filed a reply brief on December 3, 1982.

The company did not complete the rate design portion of its permanent rate filing until December 15, 1982. This necessitated separate procedural schedules for revenue requirements and rate design issues in the permanent case, as well as separate briefing schedules for these issues.

On February 14, 1983, the attorney general, the coalition, FCAC, and the EOER submitted their initial briefs on cost-of-service issues associated with the company's permanent rate application. The company filed its cost-of-service **[*8]** brief on February 28, 1983. The attorney general, the coalition, and FCAC submitted reply briefs on March 4, 1983.

On March 21, 1983, the company, Monsanto, and Kimberly-Clark, [4] and petitioners filed their initial briefs on rate design issues. The company and Monsanto and Kimberly-Clark filed reply briefs on these issues on March 28, 1983.

The issues in this case concern matters of rate base, cost of service, rate of return, capital structure, the Northeast Utilities generation and transmission agreement ("NUG&T"), the Millstone 3 project, rate design, and customer service. They are discussed hereinafter under those headings.

A. *Interim Request*

[1, 2] Contemporaneously with the filing for permanent rate relief, the company petitioned the department for interim relief in the amount of $ 5,310,000. This amount represents an adjustment to wage and salary expenses and related increases in social security taxes. Specifically, the adjustment refleets actual employees and salary levels' at the end of the test year, an escalation of certain wages to reflect a new union wage contract effective July 1, 1982, and associated social security taxes.

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[4] Monsanto and Kimberly-Clark filed a joint brief.

The interim rate relief request was based on **[*9]** the interim relief standard set forth *in Re New England Teleph. & Teleg. Co. (1980) 41 PUR4th 121*, and Re Western Massachusetts Electric Co. (1981) D.P.U. 557. That standard was intended to address directly the negative impact of regulatory lag upon utility companies in an inflationary economy. D.P.U. 380. Under this standard, the department agreed to consider in the context of an interim rate case a limited number of expenses (*41 PUR4th at pp. 126, 127)*:

". . . which have in fact been incurred or are otherwise known and measurable; which, based on department precedent, would not be at issue in the main proceeding except as to perhaps the precise level of the expense; and where, in all likelihood, the moving party would receive the amount requested."

The intervenors oppose the interim rate relief sought by the company. They contend that the company's proposed interim adjustment does not satisfy the criteria required by the D.P.U. 380 standard. In addition, FCAC advocates abandonment of the D.P.U. 380 standard, arguing that economic conditions no longer justify its application.

We find that the company's proposed interim request did not satisfy the requirements of the D.P.U. 380 standard. The adjustment proposed by WMECo was not a clear-cut, uncontestable adjustment **[*10]** as envisioned by D.P.U. 380. During the course of the interim proceeding, the company's witness testified that a portion of WMECo's wage and salary expenses are flowed through the NUG&T. However, the company was unable to provide any accounting of the impact which the agreement has on WMECo's payroll expense. This factor so complicated the company's adjustment that it was impossible for the department to determine at that stage of the proceeding that WMECo would in all likelihood receive the amount requested in its interim filing. It is for this reason that we find that the adjustment did not satisfy the D.P.U. 380 standard. [5]

The complications inherent in the company's interim adjustment combined with the rigorous time schedule in this case have precluded the department from issuing a decision on the company's interim request before now. [6] The company's petition for interim relief is now moot since the payroll issue raised by that request is resolved in this order. However, we find it appropriate to reaffirm here our recent statement *in Re Fitchburg Gas & Electric Light Co. (1983) 52 PUR4th 197*, concerning the department's requirements and guidelines for petitions for interim relief.

General Laws Chap 164, § 94, allows the department to suspend for six months the **[*11]** effective date of proposed utility rates pending an investigation of their propriety. There is no express statutory provision allowing companies to obtain interim rate relief during the pendency of such an investigation. As we noted *in Re Fitchburg Gas & Electric Light Co., supra, 52 PUR4th at p. 201*,

". . . historically, the interim relief procedure existed as a device to provide relief to companies which demonstrated by 'clear and convincing' evidence that such relief was necessary 'to avoid probable, immediate, and irreparable harm either to its business or to the interest of its customers.'" See also Re Boston Edison Co. (1978) D.P.U. 19300-A.

It was the department's position that ". . . a genuine emergency must exist before such [interim] increases will be granted." Re Western Massachusetts Electric Co. (1975) D.P.U. 18252. The department modified this so-called "emergency" standard *in Re New England Teleph. & Teleg. Co. (1980) 41 PUR4th 121*. In that case the department announced that it would consider in the context of an interim rate case a limited number of essentially uncontestable known and measurable expense items.

The department further stated that the intent in modifying the interim relief standard was "... to directly address the negative impact of regulatory lag upon a company in an **[*12]** inflationary economy." D.P.U. 380. However, as we noted *in Re Fitchburg Gas & Electric Light Co., supra, 52 PUR4th at p. 202*:

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[5] The payroll costs are associated with X.VMECo employees and WMECo's share of payroll of NUSCo and Northeast Nuclear Energy Company ("NNECo") employees.

[6] We note that WMECo's tardy completion of the rate design portion of its filing prolonged the case and protracted procedural and briefing schedules.

"Since the adoption of the modified standard in D.P.U. 380 companies have, with increasing frequency, sought interim relief and have sought to expand upon the reasons for interim relief. This experience indicates that the broadening of our previous standard has served mainly to impose administrative burdens upon an already tightly constrained six-month suspension period. The filing and reviewing of such interim proposals have presented serious problems in the expeditious and proper treatment of general rate filings."

Thus, the department announced its intention to limit interim relief to situations which meet the emergency standard enunciated in Re Western Massachusetts Electric Co. (1975) D.P.U. 18252, and Re Boston Edison Co. (1978) D.P.U. 19300-A. The complications of the interim adjustment proposed by WMECo in this case and the administrative burdens which have resulted from it only serve to illustrate further the necessity of returning to this standard. We reaffirm our Fitchburg holding here, and put companies on notice that henceforth interim relief will be allowed only in extraordinary cases where a genuine emergency **[*13]** is clearly shown to exist.

B. *WMECo's Record of Compliance toith Department Orders*

[3] The order issued by the department in the company's previous rate case, D.P.U. 957, May 28, 1982, instructed the company to comply with five separate directives. Specifically, WMECo was ordered to perform a fuel expense lead-lag study, to report the actual value of its capacity purchases, to prepare a report studying alternative allocation methods for the NUG&T by August 1, 1982, to supply details of the company's allocation of overtime wages to expense and capital, and to file an amendment to the NUG&T with FERC. However, by the time the company filed its next rate case on October 15, 1982, WMECo had complied with only one of these five directives, and that response was tardy. The report on the alternative allocation methods for the NUG&T which the company was ordered to file by August 1, 1982, was not submitted until October 15, 1982, the same day the rate case filing was made.

On December 9, 1982, the attorney general filed a motion to dismiss which was partially based on the company's failure to comply with the directives issued in D.P.U. 957. However, the company complied with the other four directives before the department ruled on **[*14]** the attorney general's motion on January 24, 1983. [7] The department denied the attorney general's motion on the ground that the company had ". . . met the threshold filing requirements set forth in D.P.U. 957." Order on the attorney general's motion to dismiss.

In his brief, the attorney general again raises the issue of the company's untimely compliance with the directives issued in D.P.U. 957. The attorney general's concern goes to the fact that failure to include such required information in the initial rate case filing effectively deprives the department and intervenors of the use of the full suspension period for consideration of these issues. The attorney general urges the department to specify in future orders whether a directive to address a particular issue in a subsequent case constitutes a filing requirement. If so, he would have the department put companies on notice that failure to comply with such directives in initial rate case filings, without first seeking a waiver of the requirement based on good cause shown, will render the filing subject to rejection or dismissal.

The department shares the attorney general's concern in this regard. Our previous denial of the **[*15]** attorney general's motion to dismiss should not be construed as tacit approval of the company's failure to comply with department directives in a timely fashion. On the contrary, we are very much troubled by what we perceive as an increasingly cavalier attitude on the part of the company toward providing timely and accurate responses to requests for information made by both the department and intervenors. [8] The six-month suspension period is becoming increasingly constrained by the growing complexity and number of issues which must be addressed in the course of a rate proceeding. As the attorney general correctly points out, when information on these issues is not supplied until well into the proceeding, the department and intervenors are effectively deprived of the use of the full suspension period.

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[7] Two of the requested items were filed on December 27, 1982; the third was filed on December 29, 1982. The FERC filing was made on November 8, 1982.

[8] We are particularly troubled by the company's response in the area of rate design. See Section VIII, *infra*.

The department has a responsibility to the public to ensure that the interests of ratepayers are protected and that the entire six-month statutory suspension period is available to examine the propriety of a rate filing. It is the department's duty to ensure that companies are not able to circumvent the full statutory review period by delaying the filing of necessary information.

[*16] Accordingly, we hereby put all companies on notice that directives in department orders to address specific issues should be regarded as creating specific filing requirements which must be included in subsequent rate case filings. Failure to include this information in the initial rate case filing, without first affirmatively seeking a waiver of the requirement for good cause shown, will render the filing subject to rejection or dismissal. See Re Massachusetts Electric Co. (1980) D.P.U. 136, affd sub nom. Massachusetts Electric Co. v Massachusetts Dept, of Pub. Utilities (Mass Sup Jud Ct 1981) -- Mass --, *421 NE2d 449*.

II. *Rate Base*

The company's exhibits show that as of June 30, 1982, the retail portion of its utility plant in service was $ 496,011,000. In determining its rate base for this proceeding, the company used a gross retail plant figure of $ 499,454,000, which includes adjustments for post-test-year additions. The company's final recommended net retail rate base of $ 332,761,000 reflects pro forma adjustments to other components of rate base, in addition to depreciation reserve and other offsets to gross plant. The intervenors have contested several of the proposed adjustments to rate **[*17]** base, and each is treated separately below.

A. *NRC-mandated Safety Additions to Millstone 1*

[4-6] The company has proposed a $ 3,443,000 adjustment to test-year-end plant in service to reflect post-test-year safety-related additions to the Millstone 1 plant. [9] The proposed adjustment reflects three plant additions at Millstone 1 which were completed by the end of the 1982 Millstone 1 outage. The three additions were mandated by the Nuclear Regulatory Commission ("NRC") and are all safety related.

No intervenor contested the company's proposed adjustment. The company contends that the adjustment should be allowed since it represents safety-related additions required by the NRC, which were completed and placed in service by the end of the 1982 Millstone 1 refueling outage, and the actual cost of which is known and measurable. In support of this position, the company cites *Re Boston Edison Co. (1980) 40 PUR4th 67*, and *Re Boston Edison Co. (1982) 46 PUR4th 431*. In those cases the department approved adjustments to rate base which reflected post-test-year NRC-mandated safety-related additions to Pilgrim Unit 1.

We find that the current proceeding may be distinguished from the cited cases on its facts, and that the company's citation of D.P.U. 906 and D.P.U. 160 as authority for its proposed adjustment is inapposite. Historically, the department has allowed a known post-test-year adjustment to rate base only where the addition significantly increased a company's rate base or represented a sizable capital investment. This was the standard applied by the department in approving a post-test-year addition to rate base in Re Boston Edison Co. D.P.H. 18200. Sept. 30, 1975. D.P.U. 18200 involved consideration of the treatment to be accorded Boston Edison Company's 600-megawatt Mystic 7 generating station. That unit had been placed in operation approximately six months after the close of the test year. The total cost of the plant was $ 145 million, and it increased the company's plant in service by 13 per cent. Because the operation of Mystic 7 was a known change and because of **[*18]** the unit's size and importance to Boston Edison Company's overall rate base, the department held that special consideration was warranted and treated Mystic 7 as though it had been in operation throughout the test year.

The department subsequently modified this "significant impact" standard somewhat *in Re Boston Edison Co. (1980) 40 PUR4th 67*, and *Re Boston Edison Co. (1982) 46 PUR4th 431*. In its review of post-test-year additions to rate base in those cases, the department looked to the nature of the additions as well as to their size and impact on the company's rate base. Specifically, the department gave particular consideration to nuclear plant additions which

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[9] The $ 3,443,000 figure, submitted December 30, 1982, reflects the actual cost of the plant additions; the initial filing contained an estimate of 83,656,000.

were safety related and which had been mandated by the NRC. However, the department's approval of post-test-year plant additions in both of these cases was not premised solely on the fact that these additions were safety related and were NRC mandated. Rather, the department also recognized ". . . the size and importance of the capital investment by the company in these additions." D.P.U. 160, p. 16. In both cases the proposed adjustments were determined to be extraordinary additions to rate base.

The circumstances in this proceeding differ considerably from those in D.P.U. 18200, [10] D.P.U. 160, and D.P.U. **[*19]** 906. What is at issue here is not an extraordinarily large addition which would significantly alter the company's rate base. The additions represented by the company's proposed adjustment reflect a cost of $ 3,443,000, which must be reviewed in the context of WMECo's plant in service of $ 496,011,000. When considered in this light, the proposed adjustment does not represent a sizable capital investment or a significant addition to the company's rate base. In fact, the proposed adjustment represents only 0.69 per cent of the retail portion of the company's plant in service, and approximately one per cent of WMECo's total year-end rate base. We do not consider such an amount to be significant enough to warrant a post-test-year addition to rate base under either the traditional "significant impact" standard as enunciated in D.P.U. 18200, or the modified standard applied in D.P.U. 160 and D.P.U. 906. Accordingly WMECo's $ 3,443,000 adjustment is herby denied.

We turn now to the standard which will be applied in future proceedings. Prior to D.P.U. 160 and D.P.U. 906, the department allowed known post-test-year adjustments to rate base only where the additions significantly increased **[*20]** a company's rate base or represented a sizable capital investment. Re Boston Edison Co. D.P.U. 18200, Sept. 30, 1975; Re Boston Edison Co. (1976) 16 PUR4th 1; *Re Western Massachusetts Electric Co. (1980) 37 PUR4th 219*; *Re Edgartown Water Co. (1980) 41 PUR4th 106*. The department has consistently excluded from rate base ordinary plant additions occurring after the close of the test year. *Re Edgartown Water Co. (1980) 41 PUR4th 106*; Re Western Massachusetts Electric Co. (1981) D.P.U. 558. This policy is based on the presumption that, absent significant changes to the rate base, the test-year-end rate base is the appropriate known and measurable asset basis for establishing prospective rates. As we have previously stated:

"Ordinary plant additions occurring after the close of the test year are excluded from rate base, in part because, while normal additions may be easily identified, offsetting periodic retirements from plant in use are not. Therefore, the department, viewing these changes as balancing one another, has tended to adhere to the rate base structure as it occurred during the test year." *Re Edgartown Water Co. 41 PUR4th at p. 108*.

The department has consistently applied this standard in the past, and we will continue to adhere to it in future proceedings. We hereby put all companies on notice that the department will no longer look to the nature of post-test-year rate base additions. Rather, **[*21]** post-test-year additions will be allowed only where a company can demonstrate that the addition has gone into service, and has significantly increased a company's rate base.

B. *Working Capital*

[7, 8] The company in its day-to-day operations requires working capital to pay for its operation and maintenance costs as well as its fuel expenses. In basic terms, a utility's working capital allowance is designed to enable a company to meet its cash requirements during the interval between a cash expenditure relating to the provision of services and the receipt of the customer's payment. Working capital is provided either by funds internally generated by the company or from short-term borrowings. The company is entitled to be reimbursed for the costs associated with the use of its funds or for the interest expense it incurs on such borrowings. This reimbursement is accomplished by adding a working capital component to the rate base computation.

In this proceeding, the company proposes to add to rate base an allowance for cash working capital in the amount of $ 19,925,000. Western Massachusetts Electric Company used 45/360 of the retail portion of its test-year operation, maintenance, and fuel **[*22]** expenses to derive the working capital component of rate base. Specifically,

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[10] They are particularly dissimilar from those in D.P.U. 18200 since in the interim the department has adopted the use of year-end rate base.

this figure consists of a 45-day cash requirement to cover operating and maintenance expenses of $ 70,006,000 and fuel expense of $ 79,395,000. The calculation contained in WMECo's initial filing assumes that its cash working capital needs will be met by one-eighth of its operation, maintenance, and fuel expenses, which equals forty-five days of a 360-day year.

In D.P.U. 20279 [37 PUR4th 219] (1980), the department found that a 45-day numerator an a 360-day denominator provided an appropriate basis to use in calculating the cash working capital requirements of this company. This treatment was continued in the company's next two rate cases, D.P.U. 558-B. (1981) and D.P.U. 957 (1982). Thus, the appropriateness of the 360-day method was not raised as an issue in this proceeding, and no intervenor contested its application. In light of this situation, and in order to provide reasoned consistency, we will accept the use of the 360-day method in this proceeding.

In so finding, we note that this 360-day convention has not been universally applied to all companies under the department's jurisdiction. A number of companies have used **[*23]** a 365-day denominator in calculating cash working capital requirements. *Re Fitchburg Gas & Electric Light Co. (1983) 52 PUR4th 197*; Re Boston Gas Co. (1982) 49 PUR4th 1; Re Commonwealth Gas Co. (1982) 50 PUR4th 85; Re Massachusetts Electric Co. D.P.U. 800, Jan. 29, 1982.

Generally, there are two accepted methods used to calculate a company's working capital needs. The first is based upon a lead-lag study which determines the actual amount of cash needed by the company to meet expenses that fall due before revenues are received. However, because of the Complexity involved in analyzing and determining the accuracy of lead-lag studies for the multitude of items included in a company's cost of service, the department has concluded that working capital needs are best approximated by using an industry convention which assumes that forty-five days' worth of the company's operation and maintenance expenses will reflect its cash working capital needs. Re Boston Gas Co. (1982) 49 PUR4th 1. Since the 45-day convention is used as a proxy for a lead-lag study, which is based on the number of days in a year, we find that the proper denominator to be used in calculating cash working capital is 365, rather than 360. Accordingly, we hereby put all companies on notice that in the future, rate filings which calculate operation and maintenance cash working capital requirements **[*24]** on the basis of the 45-day convention shall use 365 days as the denominator. [11]

We now turn to a discussion of specific working capital adjustments included in WMECo's filing.

1. *Capacity Sales Revenues in Working Capital*

[9] Included in the operation and maintenance expense figure used by the company to compute working capital is a pro forma adjustment to reflect capacity sales revenues. Specifically, test-year expenses are adjusted to reflect a $ 249,000 increase in the cost of capacity purchases and a reduction in revenues from capacity sales of $ 1,858,000. The company books both capacity sales revenues and capacity purchase expenses to the operation expense Account 555 -- purchased power. Thus, increased capacity expenses are combined with decreased capacity revenues, resulting in a net increase of $ 2,107,000 to capacity expense. [12]

The attorney general contends that the total operation expense included in the company's working capital calculation is overstated. He argues that total operation expense should include only capacity purchase expenses and should not include any capacity sales revenues. This argument is premised on the attorney general's contention that revenues derived from capacity sales should **[*25]** be booked to Account 447, [13] rather than to Account 555.

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[11] See Section II, B-2, *infra*, for a discussion of the proper determination of working capital requirements for fuel.

[12] See Section III, I, *infra*, for further discussion of this adjustment.

[13] Account 447 is a revenue account for sales for resale to municipalities.

The company maintains that its computation of working capital is in complete accord with the requirements of the Uniform System of Accounts with respect to Account 555. Western Massachusetts Electric Company further argues that its method of booking both capacity purchase expenses and capacity revenues to Account 555 results in reduced operation expense, since capacity expenses are netted against capacity revenues. The company maintains that the attorney general's proposal to remove capacity revenues from Account 555 would result in an increase to operation expense in working capital. Western Massachusetts Electric Company contends that this is so because in that instance there would be no revenue credit to net against rate year capacity purchase expense.

We find the company's inclusion of capacity sales revenues in its working capital calculation to be proper. The company is correct in its assertion that under the Uniform System of Accounts it is appropriate to book capacity sales revenues to Account 555. Moreover, we concur with the company's analysis of the effect which the attorney general's proposal would have. Accordingly, **[*26]** we will allow capacity sales to be included in the working capital calculation. [14]

2. *Fuel Expense in Working Capital*

[10, 11] The working capital calculation in the company's initial filing is based on a 45-day lag for fuel expense, using average test-year fuel prices, a normalized generation mix, and a 70 per cent nuclear capacity factor. Some two months after the initial rate case filing was submitted to the department, the company filed the fuel expense lead-lag study which the department had ordered it to perform in D.P.U. 957. The purpose of the study is to calculate the average number of days that investors must support the fuel expense portion of the company's cost of service. As Exh AG-77 indicates, overall the study attempts to determine the difference between the number of days between the delivery of service and the time at which payment is made by the ratepayer, compared to the number of days between the delivery of service and payment by the company of the fuel used to generate the electricity. The company study indicates that WMECo experiences a net lag of twenty-six days with respect to its fuel expense.

As Exh AG-77 indicates, in calculating total revenue lag days WMECo added the simple **[*27]** monthly average of unbilled revenues to the monthly average accounts receivable balance. This figure was then divided by the average daily cash receipts, resulting in the average number of days of cash receipts represented by accounts receivable and unbilled revenues. To this average number of days fifteen days (midpoint of the billing period to the meter reading date) and two days (number of days from the meter reading date to the billing date) were added to calculate the total revenue lag days.

In light of the lead-lag study, the attorney general argues that an adjustment to the filed working capital allowance to reflect a minimum 26-day lag for fuel expense is required. In addition, he contends that the study filed by WMECo overstates the net fuel lag since it includes unbilled fuel revenues in the calculation of the number of days' lag in the collection of fuel revenue ("revenue lag days"). He therefore advocates the use of a net fuel lag of 12.5 days.

The company contends that its study does not overstate the number of revenue lag days it experiences! Western Massachusetts Electric Company further argues that, although the study indicates that twenty-six days is the appropriate **[*28]** period to use for the fuel expense portion of working capital, it may not be proper to deviate from the 45 day convention for total working capital which has been applied in its previous rate cases. The company's rationale for this argument is that when working capital is bro ken down into its various components, some components may show a lag of less than forty five days and some may reflect a lag of more than forty-five days. Thus, the company would have the department utilize the 43-day convention for total working capital. The company further maintains that, in the event the department adjusts fuel expense for the 26-day lag, the company should, if it elects, be given the opportunity in future cases to provide lead lag studies for other portions of working capital.

The company's representation of the department's use of the 45-day convention for working capital is inaccurate. This convention has been applied consistently only with respect to operation and maintenance expenses. The department has frequently departed from the 45-day convention with respect to fuel expense and purchased gas

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[14] The actual amounts to be included in Account 555 will be derived pursuant to our discussion in Section 111-1, infra

expense on the ground that these items constitute a significant portion of the working capital requirement and have significantly different lead-lag characteristics from general operation and maintenance expenses as a group. Re Boston Edison Co. (1982) 46 PTTR4th 431; Re Boston Gas Co. (1982) 49 PUR4th 1; Re Bay State Gas Co. D.P.U. 777, Jan. 31, 1982.

The importance of separately determining fuel working capital requirements has increased in recent years as the magnitude of this expense relative to general operation and maintenance expenses has grown in recent years.

In light of the evidence presented in the company's lead lag study, we decline to apply the 45-day convention for the fuel working capital in this proceeding. The company's study better reflects **[*29]** what WMECo's fuel lag experience will be in the future. The record clearly shows that the company experiences a net fuel lag which is significantly less than forty-five days. Use of the 45-day convention of fuel working capital is unsupported by the evidence and would result in a distortion of the company's actual experience, especially considering that fuel expense constitutes a significant portion of the company's working capital requirement. As the Massachusetts supreme judicial court has stated:

"The 45-day figure is a widely used convention, but it is axiomatic that the regulatory agency 'may quite reasonably and properly take into account factors which reduce the need as well as those which increase it.'" *Boston Edison Co. v Massachusetts Dept, of Pub. Utilities (1978) 375 Mass 1, 22, 375 NE2d 305*, quoting *Alabama-Tennessee Nat. Gas Co. v Federal Power Commission (CA3d 1953) 99 PUR NS 141, 203 F2d 494, 498*.

Accordingly, we will not use the 45-day convention for working capital with respect to fuel expense.

We turn now to the issue of the proper number of lag days to be included in the working capital calculation. The attorney general advocates the use of 12.5 days instead of the 26 day figure indicated in the company study. This argument is premised on his contention that the company's study overstates net fuel lag because it includes unbilled revenues. He **[*30]** argues that the inclusion of unbilled revenues in its in double counting. Western Massachusetts Electric Company maintains that such revenues are properly included in the fuel revenue lag calculation since, like accounts receivable, they represent service delivered but not yet paid for.

After reviewing the evidence presented on this issue, we find that the compuny has not adequately explained or justified the inclusion of unbilled revenues in its lead-lag study. One can reasonably conclude from the present record that the company's use of unbilled revenues results in double counting. The explanation provided by the company's witness does not alleviate our concern. In fact, the witness's responses only serve to confuse the issue. In light of the evidence in the record, we are unpersuaded by WMECo's assertion that its inclusion of unbilled revenues in the fuel lag calculation does not result in double counting. Accordingly, we hereby approve the 12.5-day lag for fuel expense advocated by the attorney general.

C. *Fuel Supplies*

The company maintains an inventory of fuel supplies which it uses to generate electricity. Shortly after receiving the fuel it places in inventory, the company pays **[*31]** its suppliers. It does not, however, receive payment for this fuel from its customers until sometime after it is distributed and billed to them. The company finances this inventory pending distribution to and payment from its customers through use of its own capital or by short-term borrowings. It is entitled to be reimbursed for the costs associated with using its own funds or for the interest expense it incurs on funds borrowed for this purpose. This reimbursement is accomplished by establishing rates which allow a rate of return to be earned on a rate base which includes an amount representing the company's average investment in fuel inventory.

The company's filing uses a 13-month test-year average value for the fuel supplies component of rate base. The retail portion of that value amounts to $ 4,936,000. The coalition takes issue with this adjustment, and advocates the use of a spot value for the company's fuel supplies. Specifically, the coalition would have the department use the one-month value as of November 30, 1982, arguing that this better reflects the recent decline in the price of oil.

In the company's previous rate proceeding, D.P.U. 957, we specifically rejected **[*32]** the use of a post-test-year spot value for fuel inventory in rate base. As we noted in that case:

"There is no consistent pattern of price change and no evidence that . . . spot price is more representative than the test year average is of the rate year value of fuel inventory." Re Western Massachusetts Electric Co. (1982) D.P.U. 957.

Nor has any more persuasive evidence concerning the reliability of spot values been presented in this proceeding. On the contrary, the record indicates that there was considerable fluctuation in the test-year monthly values of the company's fuel supplies. For example, the highest monthly value for fuel supplies occurred in July of the test year, while the two lowest values occurred in March and October. In light of this evidence, we are unpersuaded by the coalition's argument that a spot price is more representative than the test-year average of the rate year value of fuel inventory. Accordingly, we will use the 13-month average value of $ 4,936,000 to reflect the fuel supplies component in rate base.

III. *Cost of Service*

A. *Pension Expense Adjustment*

[12] The company booked $ 2,723,000 to pension expense during the test year. Western Massachusetts Electric Company seeks to **[*33]** adjust this amount by a total of $ 556,000 in order to reflect increases to its pension expense incurred in post-test-year 1982 and projected to be incurred in 1983. The adjustment requested by the company is made up of three separate components. The first, in the amount of $ 110,000, reflects an increase in pensions effective September 1, 1982, for employees who retired before January 1, 1982. This adjustment is uncontested by the intervenors. The second part of the adjustment increases test-year pension expense by $ 317,000 to reflect the total 1982 pension expense. The level of this proposed adjustment is contested by the coalition. The final component of the adjustment is an increase of $ 129,000, which the company contends is necessary in order to adjust its test-year pension expense to reflect the projected 1983 level of this expense. This adjustment is opposed by both the coalition and the attorney general. We will address each of these three components separately below.

Western Massachusetts Electric Company first proposes to increase its test-year pension expense by $ 110,000 to reflect an increase in pensions which became effective September 1, 1982, for employees who **[*34]** retired before January 1, 1982. The record indicates that employees who retired in 1979 or earlier received a 9 per cent pension increase, employees who retired in 1980 received a 6 per cent increase, and employees who retired in 1981 received a 3 per cent increase. Based on the evidence in the record, we find that this proposed adjustment reflects a known and measurable post test-year increase in pension expenses. Accordingly, we will allow this $ 110,000 adjustment.

The second portion of the company's pro posed adjustment is a $ 317,000 increase which is intended to adjust its test-year pension expense to reflect the actual 1982 pension expense. This adjustment is based on a March, 1982, actuarial report prepared for the company by Towers, Perrin, Forster & Crosby. The coalition takes issue with the level of this proposed adjustment. Specifically, the coalition contends that the $ 317,000 adjustment should be reduced by $ 51,000 to $ 266,000. [15]

The coalition's argument is premised on information contained in the 1982 actuarial report. That document indicates that, for the Northeast Utilities ("NU") system as a whole, the 1982 "minimum contribution before application of a credit **[*35]** balance" was $ 25,941,042. The report further indicates that application of this so-called "credit balance" resulted in a "minimum required contribution" of $ 25,497,251.

The $ 317,000 adjustment proposed by the company is based on the $ 25,941,042 figure, which is the "minimum contribution before application of the credit balance." The coalition argues that WMECo's adjustment is more

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[15] The $ 51,000 represents the retail portion of YVMECo's share of the "credit balance."

appropriately based on the "minimum required contribution" of $ 25,497,251, and that the $ 444,000 "credit balance" reflects interest and earnings on the company's contribution to the pension plan, and docs not actually reflect cash paid by WMECo. Thus, the coalition argues that this figure should not be included as a basis for WMECo's pension adjustment.

In response, the company alleges that the coalition misunderstands the nature of the $ 444,000 "credit balance." The company maintains that the "credit balance" relates solely to the timing of contributions made to the plan, and docs not affect the level of expense actually supported by WMECo. The company also argues that the $ 317,000 adjustment complies with the department's previous treatment of this expense in D.P.U. 957.

We are unpersuaded **[*36]** by the coalition's argument that the level of expense proposed by the company for this adjustment is overrated. Although the rprnrH is somewhat confused on the exact nature of the $ 444,000 credit balance, we can find no evidentiary support for the coalition's contention that it represents interest and earnings on the company's contribution to the pension plan. The company's cost-of-service witness testified on cross-examination that the $ 25,941,000 booked figure was actually paid into the plan in cash. Moreover, as the company correctly notes in its brief, the proposed # 317,000 adjustment is in accord with our treatment of this expense item in D. P.U. 957. In considering this issue, we note that rates are designed to collect the annual amount of various expenditures. The company has clearly stated that it paid $ 25,941,(XX) into the plan in cash. We find that WMECo has sufficiently demonstrated that this is the amount which was incurred during the test year. Accordingly, we find the proposed adjustment to be known and measurable, and will therefore allow a $ 317,000 increase to test-year pension expense.

The final component of the company's proposed pension expense adjustment **[*37]** is a $ 219,000 increase to adjust its test-year pension expense to reflect projected 1983 pension expense. Both the attorney general and the coalition oppose this proposed adjustment. They characterize the adjustment as speculative, arguing that there is no indication in the record what net actuarial gain was assumed in the estimate, or whether the estimate reflects an assumption concerning the effect of possible investment gains, and therefore assert that it is predicated on an arbitrary assumption regarding return on investment. They also contend that it does not reflect a known and measurable change from test-year results since it is not based on a 1983 actuarial report. In making this argument they point out that the 1983 report will be the ultimate basis for WMECo's 1983 contribution. They cite as support for their position Re Bay State Gas Co. (1982) D.P.U. 1122, and Re Fitchburg Gas & Electric Light Co. (1983) D.P.U. 1214. In both of those cases the department disallowed proposed adjustments for 1983 pension expense on the ground that they did not reflect known and measurable post-test-year increases.

The company argues that the proposed $ 129,000 adjustment should be allowed. **[*38]** Western Massachusetts Electric Company attempts to defend the adjustment on the ground that it is currently booking higher pension costs for 1983. The company also cites *Boston Edison Co. v Massachusetts Dept, of Pub. Utilities (1978) 375 Mass 1, 31, 375 NE2d 305*, for the proposition that "[t]he department has also permitted adjustments reflecting estimated increases when the record shows that the estimate is likely to be correct, or in any event when the estimate appears to be reasonable."

We find the company's citation of this authority to be inapposite. There is insufficient support in the record for the contention that the company's estimate of 1983 pension expense is "likely to be" Or "appears to be reasonable." We find the company's proposed $ 129,000 adjustment to be speculative. Based on department precedent, it must be disallowed. Re Bay State Gas Co. (1982) D.P.U. 1122; Re Fitchburg Gas & Electric Light Co. (1983) D.P.U. 1214. As we have previously stated in Re Fitch burg *Gas & Electric Light Co. (1983) 52 PUR4th at pp. 205, 206*:

"The actual 1983 expense will not be known until sometime in 1983 because, at the end of each year, the company provides to its actuary census data on its employees. The actuary uses the updated data to reevaluate the pension plan and make his actuarial' recommendation. Since the company **[*39]** failed to present a study, we are unable to assess the reasonableness of the estimate."

Accordingly, a $ 427,000 increase to test-year pension expense is hereby allowed.

B. *Storm Expense*

[13] The company incurred $ 330,000 in storm-related nonpayroll operation and maintenance expense during the test year. Western Massachusetts Electric Company has included the entire expense in test-year cost of service.

The attorney general and the coalition oppose this treatment, arguing that the storm expense should be amortized over a period of years. The attorney general recommends a three-year amortization period, while the coalition advocates the use of a five-year period. Moreover, the coalition contends that the proper figure to be amortized is $ 318,000 rather than $ 330,000, arguing that $ 12,000 of the $ 300,000 represents salaries which have been adjusted for elsewhere.

The company maintains that amortization of this expense is not warranted. In making this argument, WMECo points out that the $ 330,000 represents only approximately 0.4 per cent of the company's pro forma retail operation and maintenance expense. The company cites as support for its position *Re Western Massachusetts Electric Co. (1980) 37 PUR4th 219*. In that case the department **[*40]** held that amortization of the company's test-year storm expense was not appropriate, and found that $ 454,000 in storm expense did not have an extraordinary financial impact on WMECo's operations.

The department's policy with respect to amortization of storm expense is well settled. We will allow amortization of storm expenses which have had an extraordinary financial impact on cost of service. Re Massachusetts Electric Co. (1978) D.P.U. 19376; Re Boston Edison Co. (1982) D.P.U. 19300; Re Eastern Edison Co. (1982) D.P.U. 1130; Re Massachusetts Electric Co. (J982) D.P.U. 1133. The issue of amortization docs not turn solely on the precise level of the expense. Rather, the test is whether the storm expense, whatever its level, has had an extraordinary financial impact on a company's cost of service. The recommendation of the attorney general and the coalition must therefore be judged against this standard.

Based on a review of this record, we find that the test-year overall level of storm-related expenses is representative of the normal level of recurring expense for this item. Accordingly, we will allow the single storm-related expense of $ 330,000 to remain in cost of service. **[*41]**

C. *Hydro-Quebec Feasibility Study*

[14, 15] During the test year, the company expended $ 114,000 for a feasibility study examining the establishment of a transmission line for power from Hydro-Quebec. This proposed interconnection is to consist of a high-voltage direct current transmission line from the proposed Des Cantons substation on the Hydro-Quebec system near Sherbrooke, Quebec, to a proposed terminal having an approximate rating of 690 megawatts near the Comerford generating station of the New England Power Company on the Connecticut river. The interconnection is primarily a New England Power Pool ("NEPOOL") project. Although the initial phase has been completed, the entire study is not finished and the company's cost-of-service witness indicated that it is still ongoing. The company booked the $ 114,000 which it expended during the test year to Account 566, miscellaneous transmission expenses. That account provides:

"566. Miscellaneous Transmission Expenses

"This account shall include the cost of labor, materials used, and expenses incurred in transmission office expenses, and other transmission expenses not provided for elsewhere.

"Items

"Labor:

"1 General records of physical characteristics **[*42]** of lines and stations, such as capacities, etc.

"2. Ground resistance records.

"3. Janitor work at transmission office buildings, including care of grounds, snow removal, cutting grass, etc.

"4. Joint pole maps and records.

"5. Line load and voltage records.

"6. Preparing maps and prints.

"7. General clerical and stenographic work.

"8. Miscellaneous labor.

"Materials and Expenses:

"9. Communication service.

"10. Building service supplies.

"11. Map and record supplies.

"12 Transmission office supplies and expenses, printing and stationery.

"13. First aid supplies."

The attorney general argues that the study expense should be removed from cost of service and booked instead to Account 183, preliminary survey and investigation charges. The account advocated by the attorney general provides:

"183. Preliminary Survey and Investigation Charges.

"A. This account shall be charged with all expenditures for preliminary surveys, plans, investigations, etc. made for the purpose of determining the feasibility of utility projects under contemplation. If construction results, this account shall be credited and the appropriate utility plant account charged. **[*43]** If the work is abandoned, the charge shall be made to Account 435, miscellaneous debits to surplus, or to the appropriate operating expense account.

"B. The records supporting the entries to this account shall be so kept that the utility can furnish complete information as to the nature and the purpose of the survey, plans, or investigations and the nature and amounts of the several charges.

"Note. The amount of preliminary survey and investigation charges transferred to utility plant shall not exceed the expenditures which may reasonably be determined to contribute directly and immediately and without duplication to utility plant."

The basis for the attorney general's recommendation is his contention that, since the expense will continue after the test year, the total amount of expenditures associated with the project is unknown. He further argues that it is unclear that these expenses will ever benefit ratepayers. The attorney general cites Re Eastern Edison Co. (1982) D. P.U. 1130, as support for his argument that the test-year study expense should be booked to another account. [16] In D.P.U. 1130 the department disallowed a test-year expense associated with a meter reading **[*44]** re-routing project on the ground that the project was ongoing and thus the total cost was not known and measurable. The department ordered the expense booked to Account 186, miscellaneous deferred debits.

In response to the attorney general's arguments, the company maintains that the attorney general fails to recognize the different accounting treatment required for the initial expenditures of a project as compared to later expenditures. Western Massachusetts Electric Company contends that the initial costs of the Hydro-Quebec project, including the costs of this study, will not be capitalized and that the company will therefore not be

[16] The attorney general argues in the alternative that this expense should be booked to Account 186, miscellaneous deferred debits.

reimbursed by Hydro-Quebec for any such expenses. Thus, the company contends that it should be allowed to book the $ 114,000 to Account 566 and to reflect this expenditure in test-year cost of service.

We find that the company's treatment of this expenditure is improper. As the attorney general correctly points out, the total amount of expenditures associated with the project is currently unknown, and it is presently unclear whether these expenses will ever inure to the benefit of ratepayers. Moreover, from the evidence in the record, it appears **[*45]** that this item is a nonrecurring expense. As the department stated *in Re Fitchburg Gas & Electric Light Co. (1983) 52 PUR4th at p. 210*: "Nonrecurring expenses incurred in the test year are ineligible for inclusion in the cost of service unless it is demonstrated that they are so extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period." In light of these facts, and based on our holding in Eastern Edison Co. (1982) D.P.U. 1130, we find that the $ 114,000 associated with the Hydro-Quebec feasibility study must be removed from the company's cost of service. We hereby direct the company to book this expense to Account 183. Accordingly, WMECo's cost of service must be decreased by $ 114,000.

D. *Edison Electric Institute Payments*

[16] The company participates in the activities of the Edison Electric Institute ("EEI"). Among the activities conducted by this organization are various research and publication projects. Edison Electric Institute also lobbies on issues of interest to the electric utility industry.

During the test year, WMECo incurred $ 55,271 in expense associated with membership dues for EEI. Of this amount, the company booked $ 949 to Account 426 to reflect costs associated with lobbying activities. This **[*46]** $ 949 figure was derived by applying a 2 per cent allocation factor which was supplied to the company by EEI. The remaining $ 54,322 was included in the company's cost of service.

The attorney general and FCAC maintain that the $ 54,322 must be excluded from cost of service. This argument is premised on their contention that the 2 per cent allocation factor which was used to derive EEI lobbying expense is nut inclusive of ail activities which are encompassed within any reasonable definition of lobbying. Their concern goes to the fact that Exh FCAC-57 shows that the 2 per cent allocation represents only the amount of time spent by EEI employees discussing matters with members of Congress or their staff. The intervenors argue that, since the allocation factor does not include time spent by EEI employees analyzing bills or gathering data necessary to formulate positions, its application does not accurately represent the total time and expense associated with EEI lobbying activities.

FCAC cites Re Massachusetts Electric Co. D.P.U. 800, Jan. 29, 1982, and *Re Boston Edison Co. (1982) 46 PUR4th 431*, as authority for its argument that WMECo has provided an insufficient level of detail to support its allocation. In those cases, **[*47]** the department disallowed bills for legal services submitted by a law firm which also engaged in lobbying activities. The department based its denial on the fact that the bills lacked a sufficient level of detail to account for lobbying activities. Specifically, the department criticized the bills as ". . . barren of any detail indicating the extent and nature of the services, the days on which the services were performed, the number of hours which were expended, nor was there any indication given as to who within the firm performed the services for which compensation is claimed." Re Massachusetts Electric Co. D.P.U. 800, Jan. 29, 1982, quoting *Re Boston Edison Co. (1980) 40 PUR4th 67*.

An additional basis for FCAC's opposition to this adjustment is its contention that it is unclear from the record whether the $ 54,322 figure excludes trade association advertising. As FCAC points out, the expense associated with such advertising is not properly includable in cost of service since trade association advertising provides no benefits to ratepayers. *General Laws Chap 164, § 33A*. FCAC maintains that the company failed to provide requested documentation either of advertising costs or of their exclusion from the $ 54,322 adjustment, and that therefore it **[*48]** is unclear from the record whether such costs are included in WMECo's proposed $ 54,322 cost-of-service increase.

The company defends the requested adjustment and the 2 per cent allocation factor on the ground that it was calculated by EEI, and that it is EEI's obligation to report to its members the percentage of costs devoted to lobbying. Western Massachusetts Electric Company also objects to the intervenor' reference to Exh FCAC-57 on the ground that it is hearsay. The company further argues that D.P.U. 800 and D.P.U. 906 may be distinguished from this proceeding on their facts, since those cases involved legal bills which were not itemized between legal and lobbying expense. Finally, WMECo argues that the record clearly establishes that the company does not contribute to EEI's advertising activities and that EEI advertising expenses are not included in cost of service.

We find the company's arguments unpersuasive. Based on the evidence in the record, we are unconvinced that the 2 per cent allocation factor accurately reflects total EEI lobbying activities and the expenses associated with such activities. Our concern arises because Exh FCAC-57 indicates that the 2 per cent **[*49]** allocation factor represents only the amount of time spent by EEI employees discussing matters with members of Congress or their staff's. It does not reflect time spent analyzing legislation or gathering data in order to formulate positions on various issues. Such tasks are necessary preliminaries to any conversations with members of Congress or their staff's. It is therefore arguable that at least some portion of the time spent on such matters can reasonably be regarded as lobbying activities. Since the 2 per cent allocation factor does not reflect such activities, we find that it is not an accurate representation of EEI lobbying expense.

We do not feel constrained to adopt the allocation factor simply because it was supplied to the company by EEI. We remind WMECo that it is the company, not EEI, which has the burden of proof in this proceeding. That burden is not discharged by simply stating that the allocation factor is accurate because it was calculated by EEI.

It is incumbent upon the company to demonstrate that the allocation factor developed by EKI does in fact accurately reflect total lobbying activities and expense. We find that WMECo has failed to do that in this proceeding, **[*50]** and has provided an insufficient level of detail to support its allocation. Re Massachusetts Electric Co. D.P.U. 800, Jan. 29, 1982, *Re Boston Edison Co. (1982) 46 PUR4th 431*.

We also find the intervenors' citation to Exh FCAC-57 [17] to be perfectly proper, and the company's criticism of it to be untimely at best. Contrary to the company's assertion, this document is acceptable evidence under the department's evidentiary standards. In any event, the proper time for WMECo to object to the document has passed. The time for the company to raise its hearsay objection was when F'CAC moved to have the document admitted into evidence. Since WMECo chose not to do so, it cannot be heard to object to its admission on hearsay grounds at this juncture.

In addition, we find that the company's assertion that its proposed $ 54,322 adjustment excludes advertising expenses has not been fully documented. On cross-examination, the company's cost-of-service witness stated that WMECo does not pay EEI advertising expense.

However, he was unable to state with any specificity what portion of the EEI bill relates to advertising expense. Rather, he made reference to the January 12, 1981, invoice for WMECo's membership dues for participation **[*51]** in EEI. That bill was in the amount of $ 393,000, and a penciled notation on the document indicates that WMECo paid only $ 62,292.25 of that amount. With respect to the remainder of the bill, the company's witness was only able to state that "I have to assume that the rest was advertising, without specifically knowing it."

Moreover, although WMECo was twice asked by FCAC to supply documentation of the precise level of advertising expense for which it had been billed and which it had paid, the company simply failed to respond to this request. Thus, we find that the record is unclear as to whether the proposed $ 54,322 adjustment does in fact exclude advertising expense.

In light of these factors, we find that the company's proposed adjustment must be denied. Accordingly, WMECo's cost of service must be reduced by $ 54,322.

E. *Bad Check Charge*

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[17] Exhibit FCAC-57 is a letter from the president of EEI explaining EEI's activities.

[17] The company seeks to introduce a $ 5 charge for dishonored checks. As part of its initial rate filing, the company submitted a study which it contends supports the recommended $ 5 charge. The company's proposal would increase revenues by $ 9,000.

FCAC takes issue with the level of the dishonored check charge proposed by WMECo. Specifically, **[*52]** FCAC contends that the proposed charge should be reduced from $ 5 to $ 3. Its concern goes to the methods underlying the company's supporting study. FCAC criticizes the company's use of a nonquantified 83-cent loader to reflect various expenses not included in basic labor expense, such as overhead, postage, and vehicle expense, arguing that a similar type of loader was twice rejected in Re Commonwealth Gas Co. (1982) 50 PUR4th 85.

FCAC also objects to the fact that WMECo's proposed charge is based on maximum labor rates for employees and reflects charges for time not actually spent processing bad checks. FCAC further argues that the company overstates the time involved in processing bad checks. Using evidence contained in the company's study, and cross-examination of the company's witness, FCAC makes certain adjustments to labor rates and actual time spent processing dishonored checks. Its resulting recommendation is a $ 3 charge for dishonored checks.

In response to FCAC's criticisms, WMECo points out that the department recently approved $ 4 dishonored check charges *in Re Cambridge Electric Light Co. (1982) 48 PUR4th 32*, and Re Commonwealth Gas Co. (1982) 50 PUR4th 85. The company also contends that FCAC's proposed adjustments are unsupported on the record.

We disagree with WMECo's latter assertion. Our review **[*53]** of the record indicates that the evidence supports a $ 3 dishonored check charge. We share FCAC's concerns over the methods used in the company's study and the assumptions underlying it. We are particularly troubled by the fact that WMECo's proposed $ 5 charge is based on maximum labor rates. We find that use of these rates overstates the actual expense experienced by the company. Moreover, we find that WMECo has failed to justify its use of the 83-cent nonquantified loader. See Re Commonwealth Gas Co. (1982) 50 PUR4th 85. In order to be allowed such an adjustment, a company must demonstrate that its proposed charge is based on costs to ratepayers. Accordingly, we hereby deny the company's proposed adjustment, and find a $ 3 dishonored check charge to be appropriate. The appropriate increase to revenues is therefore $ 5,000 rather than the $ 9,000 contained in the company's filing.

F. *Uncollectibles*

[18] The company maintains an accrual against which it writes off bad debts as they become uncollectible. The company will ordinarily wait at least seven months from the time it issues a final bill to a customer to make the determination that the amount is uncollectible. Once that determination is made, the company writes off the account **[*54]** receivable and makes a corresponding entry reducing its reserve for bad debts. The company uses this method of accrual accounting in an attempt to match anticipated bad debts with revenues.

During the test year, the company accrued $ 1,279,000 in uncollectible expenses for residential and commercial accounts. Western Massachusetts Electric Company seeks to adjust this figure by $ 363,000. The $ 363,000 adjustment proposed by the company is made up of two components. The first applies the historical test-year twelve months' average uncollectible accrual rate to pro forma test-year residential and commercial revenues, including fuel. This results in a $ 13,000 reduction to test-year expense. The second component, in the amount of $ 376,000, reflects the company's forecasted increase in the residential and commercial accounts' uncollectibles. This forecast was developed through a univariate time series regression analysis which used actual monthly write-off data from January, 1979, through June, 1982.

The coalition, the attorney general, and FCAC dispute the forecasted $ 376,000 component of the company's proposed adjustment with two lines of argument. They first question the statistical **[*55]** validity of the company's univariate time series analysis and urge the analysis not be accorded the status of substantial evidence. Their second line of argument focuses on the uncollectibles adjustment standard announced in Re Boston Gas Co. (1982) 49 PUR4th 1, and claims the forecasted component of the company's proposed adjustment violates that standard. The coalition further argues that the $ 13,000 amount which results from the first component of WMECo's proposed adjustment also violates the D.P.U. 1100 standard, concluding that proper application of the standard would result in an $ 18,000 additional reduction in the company's cost of service.

The company contends that its proposed adjustment accurately reflects the impact of uncollectible expense on WMECo's costs of operation. Western Massachusetts Electric Company defends the $ 13,000 adjustment contested by the coalition on the ground that it conforms to the allowance for uncollectibles in D.P.U. 957.

The company asserts that the amount of revenues it is unable to collect from residential and commercial customers is increasing rapidly, due to the adoption by the department of a winter shutoff moratorium policy. The company argues that, given this increase **[*56]** in uncollectible expense, an historical averaging method will not reflect conditions that will exist when new rates will be in effect. Accordingly, WMECo would have the department increase test-year uncollectible expense by $ 376,000 to reflect the level of retail uncollectible accruals which WMECo estimates will occur in the future.

The company defends the statistical study criticized by the intervenors on the ground that it is being presented in response to concerns expressed by the department in D.P.U. 957. In that case, we indicated that we might reconsider basing allowable uncollectible expense solely on historical figures if WMECo presented ". . . a more rigorous analysis of uncollectibles in its next rate case." D.P.U. 957. The company asserts that the study presented in this proceeding is just such a rigorous analysis. The company also points out that the department has recently stated that historical uncollectible levels will be used ". . . unless it can be demonstrated that particular circumstances exist which warrant a departure from this convention." (49 PUR4th 1.) Western Massachusetts Electric Company maintains that its statistical study demonstrates the "particular circumstances" **[*57]** applicable to the company which would warrant a departure horn the use of historical uncollectible levels.

Western Massachusetts Electric Company also urges the department to consider the experience of its customer services department, arguing that studies performed by WMECo indicate that the company's pro-posed level of uncollectible expense is understated. In the alternative, the company maintains that, if the department does not accept WMECo's increased uncollectible expense adjustment, test-year uncollectible expense should be included in residual operation and maintenance expense to calculate the inflation allowance.

Western Massachusetts Electric Company is correct in its assertion that the first component of its proposed bad debt adjustment conforms with the calculation used in D.P.U. 957. The company is also correct that neither D.P.U. 957 nor D.P.U. 1100 (49 PUR4th 1) set irrefutable standards which preclude department consideration or adoption of the forecasted component of the proposed adjustment. The company's proposal, however, must be viewed in the context not only of the department's historical treatment of this cost-of-service item but also of the reasons for this treatment. **[*58]**

In D.P.U. 957, the department endorsed the concept of averaging bad debt accrual rates to develop the appropriate adjustment to the cost of service. In D.P.U. 1100, the notion of averaging was again endorsed as an appropriate method to obtain a representative level for this adjustment. That case further found, however, that in developing the rate, five years of historical loss experience as measured by accounts receivable write-offs, adjusted for recoveries of previously written off accounts, was more representative of a company's actual experience with this adjustment, for the simple reason that straight accrual rates or booked accrual amounts do not necessarily reflect the company's actual loss recovery experience. This calculation was then adopted as a standard that would be applied in all future cases ". . . unless it can be demonstrated that particular circumstances exist which warrant a departure from this convention." (49 PUR4th 1.)

The company's univariate analysis does not demonstrate such circumstances. Ignoring the numerous statistical objections to the study, the mere fact that the model does not account for the important factor of loss recovery experience disqualifies it from **[*59]** consideration. Nor does the fact that D.P.U. 957 endorsed the reasonableness of using test-year monthly experience justify departure from the standard. The department was well aware of D.P.U. 957 when it announced that the standard in D.P.U. 1100 applied to all companies.

Further reflection on the D.P.U. 1100 standard does, however, require that it be slightly modified. In both D.P.U. 957 and D.P.U. 1100, the reduction of the adjustment to an accrual rate which was then applied to test-year revenues was uncontested and accepted as appropriate. The department has no problem with the use of the accrual method for accounting purposes. We do, however, have serious doubts about its use to derive an appropriate cost-of-service level for this item. As noted in D.P.U. 957, the application of an accrual rate implicitly assumes a functional relationship between bad debt experience and revenues. The mere fact that the relationship is assumed for accrual accounting purposes does not justify its use for rate-making purposes. Consequently, absent convincing evidence which specifies and confirms this supposed relationship, we are no longer willing to assume its existence. There are other factors, **[*60]** such as general economic conditions, which affect the level of the company's bad debts. It appears to us that a company's actual bad debt experience is the relevant focus and that this experience clearly includes loss recoveries as well as write-offs. With respect to other elements, we remain to be convinced. We will therefore adhere to the standard used in D.P.U. 1100, as modified by this order.

For rate-making purposes, we shall consequently require the use of the average of the most recent five years' net write-offs. The result of this calculation will become the cost-of-service bad debt expense allowance. This normalization of bad debt expense will be updated in each succeeding rate case.

Western Massachusetts Electric Company has provided its actual net write-off experience for five calendar years (1977-81) plus the full test year. The test year overlaps calendar year 1981 by six months. In order to eliminate any distortions which may be caused by double counting six months, we will use the average of the five calendar years. If the company had provided data on a uniform basis we would have included the most recent net write-off experience in the calculation. The normalized **[*61]** bad debt expense allowance in this case, thus calculated, is $ 695,720. Accordingly, the company's cost of service must be reduced by $ 993,000.

Although WMECo advocates the inclusion of an historically based bad debt expense in the inflation allowance, we decline to do so. We find that the standard adopted in this case will adequately compensate the company for its actual loss experience.

G. *Deferred Tax Impact of No Millstone 3 Sell-down*

The company's initial filing contained an adjustment to tax expense to reflect the taxable gain which would result from the then anticipated sell-down of 37.2 megawatts of Millstone 3. During the course of this proceeding, it became clear that the anticipated sale would not be consummated. Hence, WMECo subsequently filed a revised pro forma retail deferred income tax schedule which assumes no Millstone 3 sell-down. Both the attorney general and WMECo assert that this schedule should be used to calculate retail deferred income taxes. We find this recommendation to be proper. Accordingly, we will use the company's revised schedule in calculating WMECo's tax liability.

H. *Payroll Expense*

The record indicates that as of the close of the test year there were 849 employees on WMECo's payroll. In **[*62]** addition to their salaries, the company is responsible for a certain portion of the payroll expense which is incurred by NUSCo and NNECo. Western Massachusetts Electric Company's portion of NUSCo payroll expense is allocated to the company pursuant to a service agreement which has been approved by the Securities and Exchange Commission. The company's portion of NNECo payroll expense is allocated on the basis of WMECo's ownership shares in nuclear units. Since the company owns 19 per cent of NU nuclear capacity, it is responsible for 19 per cent of NNECo's payroll expense.

The company's filing indicates that, during the test year, WMECo incurred a total amount of $ 27,605,000 in wage and salary expense. Of this amount, $ 7,990,000 and $ 3,774,000 represent the amounts of test-year payroll expense allocated to the company by NUSCo and NNECo, respectively. Payroll expense for WMECo's employees during this period amounted to $ 15,841,000.

The company seeks to increase its $ 27,605,000 test-year payroll expense by $ 5,282,000. The wage and salary adjustment proposed by WMECo is in two parts. The first adjustment of $ 1,801,000 represents an increase to test-year payroll expense to **[*63]** reflect "committed payroll" at test year-end. Committed payroll is the total payroll the company was responsible for as of June 30, 1982. It is based on employee levels on that date.

The second adjustment of $ 3,481,000 reflects a post-test-year salary increase which will be in effect during the coming year. We will address the two adjustments separately.

I. *The $ 1,301,000 Committed Payroll Adjustment*

[19] The attorney general, the coalition, and FCAC raise a number of criticisms concerning this proposed increase. One basis for their opposition is their contention that the NNECo-committed payroll adjustment improperly includes wage expense for personnel assigned to work on Millstone 3.

The record indicates that NNECo added 129 employees during the test year. This increased NNECo's employee level by 32 per cent, and results in a 22.53 per cent increase in NNECo-committed payroll over test-year levels. The intervenors assert that a significant portion of the difference between NNECo's committed payroll and actual payroll is attributable to hirings for Millstone 3, the costs of which cannot be currently charged to ratepayers.

The intervenors also criticize the adjustment on the ground that WMECo used the capitalized **[*64]** as well as the expensed portion of payroll to determine the ratio of overtime and premium wages to regular wages. They argue that this approach contravenes the concerns expressed by the department in D.P.U. 957. In that case, the department stated that "[w]e believe it is more appropriate to use only payroll expense since the inclusion of the capitalized portion may distort the overtime and premium wages included in the cost of service." D.P.U. 957, p. 60. The coalition and FCAC also argue that the annualization process used to reach the committed payroll as of June 30, 1982, is defective in that it does not reflect employee turnover rates during the test year.

Based on these arguments, the attorney general urges that the $ 850,000 adjustment representing NNECo's committed payroll be disallowed, while the coalition advocates a $ 128,000 reduction to reflect employee turnover rates. FCAC argues that the entire $ 1,801,000 adjustment should be disallowed.

Western Massachusetts Electric Company defends its proposed adjustment on the ground that it is calculated in the same manner as the wage and salary adjustment that was approved in D.P.U. 957. It asserts that intervenors' criticisms **[*65]** concerning the calculation of overtime and premium wages are unfounded, pointing to the evidence contained in Exh WM-11. Western Massachusetts Electric Company contends that this exhibit, which was filed on December 29, 1982, and which segregates the expensed and capitalized portion of overtime wages, shows that there is no distortion in the company's proposed payroll adjustment. The company also takes issue with the coalition's proposed adjustment to reflect turnover rates, arguing that it ignores the number of employees who will be added to replace those who leave.

Western Massachusetts Electric Company further contends that the intervenors' argument concerning the impact of the newly hired NNECo employees is without foundation. Western Massachusetts Electric Company states that all work on Millstone 3 is capitalized and charged to capital accounts. The company contends that the capital/expense split for test-year payroll expense removes wages associated with Millstone 3 from the cost of service.

Based on the evidence contained in the record, we find that the Millstone 3 payroll expense has been properly capitalized and is not reflected in the company's proposed adjustment. **[*66]** We therefore find that no adjustment is warranted.

Nor do we find it appropriate to make an adjustment for employee turnover rates. The company is correct that such a proposal ignores the number of employees who will be added to the payroll to replace those who leave during the year. The coalition's recommendation fails to take into account the normal fluctuations in employee levels that is inherent in the company's overall payroll. Accordingly, we find that there is no support in the record for the $ 128,000 reduction proposed by the coalition.

After reviewing the evidence on the capital/expense split for overtime wages contained in Exh WM-II, we find that the company's proposed committed payroll adjustment does not contain a distortion. However, we hereby put the company on notice that its future rate case filings must separate capital and expense for overtime and premium wages in the manner reflected on Exh WM-11.

Accordingly, we accept the company's proposed $ 1,801,000 adjustment contained in Exh WM-5, Schedule C-3.11, since it reflects a known and measurable normalization of the company's test-year wage and salary expense.

2. *The $ 3,481,000 Salary Increase Adjustment*

[20, 21] This proposed adjustment **[*67]** reflects a post-test-year salary increase. Specifically, test-year payroll expenses were adjusted to reflect 8.5 per cent increases granted to employees effective July 1, 1982, and July 1, 1983. Arguing that the alleged defects in the company's committed payroll adjustment are seriously compounded when applied to the proposed adjustment, the coalition urges disallowance of this amount.

Wc reject this argument, since we have previously found the company's proposed committed payroll adjustment to reflect a known and measurable increase. We find that the company's proposed salary increase adjustment represents a known and measurable change to test-year levels. Accordingly, we hereby allow WMECo to increase test-year payroll expense by $ 5,282,000.

Although the issue of nonunion wage increases was not raised in this proceeding, we reiterate here the standard for such increases which was recently enunciated *in Re Fitchburg Gas & Electric Light Co. (1983) 52 PUR4th at p. 204*. Specifically, companies must demonstrate:

(1) an expressed commitment by management to grant the increase;

(2) that a correlation has existed historically between union and nonunion raises; and

(3) that the amount of the increase itself is reasonable.

Although we **[*68]** allow the company's adjustment in this case, we do find it necessary to comment on one concern regarding the company's method of calculating wage and salary adjustments. We refer specifically to the impact of the NUG&T on wage and salary expense. The company's witness testified that wages and salaries and FICA-related taxes are flowed through the NUG&T, and that any credits or additional charges to WMECo under the agreement were not reflected in WMECo payroll accounts during the last year. Thus, the company was unable to provide any accounting of wage expenses flowed through the agreement during this period. Exhibit WM-2, Schedule C-3.11 shows that a significant portion of the company's payroll is related to generation and transmission. It is for this reason that we find that the impact of the NUG&rT must be considered, and we hereby direct the company to address this issue in its next rate case filing. Specifically, we will expect to sec information on exactly how credits or charges to WMECo under the agreement affect the company's payroll, and what the magnitude of that effect is so that the NUG&T credits or charges can be adjusted in accordance with adjustments to WMECo's wage and **[*69]** salary adjustments.

I. *Contract Power Sales and Purchases*

[22-26] In this proceeding the company seeks an increase in test-year cost of service of $ 2,107,000 to account for changes in power contracts. The company testified that it expects to lose $ 1,858,000 in revenues from "capacity sales," compared to the test year. It also expects an increase during the coming year of $ 249,000 in expenses from "capacity purchases." Thus, WMECo has proposed the $ 2,107,000 adjustment. The costs and revenues the company refers to are actually amounts related to the capacity charge portion of various contracts.

The company has made three arguments in support of this proposed adjustment. First, it maintains that the proposed adjustment to "capacity sales" is allowable because it follows the precedent set in Re Western Massachusetts Electric Co. (1982) D.P.U. 957. Second, WMECo states that "capacity sales to other utilities are becoming more difficult to make as load growth declines and other utilities find themselves with adequate or excess capacity," and so argues that it is reasonable to expect a decline in the amount of these sales. Third, the company asserts that it is certain that five sales contracts will terminate **[*70]** on or before October, 1983. It further asserts that it is unlikely that similar power sales will replace them.

As an alternative, the company states that "if the department . . . disallow[s] expenses associated with the company's capacity transactions, the company would have no objection to a capacity tracking clause." The company's preference, if a tracking clause is adopted, is for one that provides for quarterly adjustments.

The attorney general and the coalition oppose any adjustments to test-year contract sales or purchases. They argue that the adjustments are not known and measurable and that the adjustment for contract sales is without precedent. Both intervenors maintain that these transactions simply cannot be predicted accurately and that any adjustment to test-year sales or purchases may lead to an overrecovery by the company. The attorney general, in his re ply brief, accepts a tracking clause for capacity costs. The coalition opposes such a clause on the ground that more examination of the design and effects of such a clause is needed.

Although the department has made specific adjustments to WMECo's capacity charge expenses in the past, the arguments of the parties **[*71]** in this case go beyond the proposed adjustments. A review of the whole question of contract power revenues and expenses is necessary.

In order to determine the appropriate treatment of revenues and expenses resulting from various power contracts, we must examine the nature of the agreements under which power is exchanged. There are essentially three types of power exchanges on the wholesale level, apart from all-requirements service: sales and purchases made pursuant to a pooling arrangement ("interchange agreements"), sales and purchases made primarily for energy reasons ("opportunity contracts"), and sales and purchases of power which are made primarily for capacity reasons ("capacity contracts").

Interchange agreements establish a formal, organized relationship where energy is exchanged moment to moment on an economic basis, such as within NEPOOL. Opportunity contracts enable companies to determine the amount of power to be bought or sold on a relatively short-term basis; they operate in many respects like a spot market. Capacity contracts are for a longer term than opportunity contracts. The sale or purchase of capacity is a primary element, although there may be some economic **[*72]** energy value as well.

The method by which payment is received or made under a contract does not necessarily reflect the type of purchase or sale that is being made. While interchange under the NEPOOL agreement has no capacity or demand charges associated with it (unless the utility has insufficient capacity to meet its responsibility), exchanges under the NUG&T do have capacity-based charges. Traditionally, in New England, both opportunity and capacity contracts have an energy charge which recovers fuel costs and variable O&M costs. They also have a capacity charge the purpose of which, in the case of capacity contracts, is to recover all or most of the fixed costs of the portion of the unit or system which is sold. In the case of opportunity contracts, however, the capacity charge i.s not designed to recover the fixed costs associated with the unit, but to increase the effective cost of the power above what it costs the selling utility to produce it. The effective cost of the energy must stay below the incremental cost to the purchasing utility of producing the power itself. The "profit" the selling utility makes on opportunity contracts should go to reducing the costs to its retail **[*73]** ratepayers.

The purpose of the contracts, rather than the outward form of the charges under them, should determine how the expenses and revenues are treated. Expenses and revenues from interchange and opportunity contracts relate almost exclusively to energy. The annual revenues and expenses under these contracts can vary dramatically from year to year because the amount of power exchanged is a function not only of the availability of the units owned by a company, but also of the availability of the units of prospective buyers and sellers.

Given these characteristics, we find that expenses and revenues associated with interchange and opportunity contracts should be handled through a company's fuel charge. The fuel charge is applied on a per kilowatt-hour basis, which is the appropriate way to allocate energy-related costs and revenues. The purpose of the fuel charge is to ensure accurate recovery of volatile fuel and purchased power expenses, a description which fits interchange and opportunity contracts.

Capacity contracts must be treated differently. The energy portion of capacity contracts is already accounted for in the fuel charge. The capacity charge expenses and revenues **[*74]** associated with capacity contracts, however, are primarily demand related, and so should be in base rates and should be allocated in accordance with an appropriate cost-of-service study.

Therefore, the department establishes the following standard for treatment of revenues and expenses associated with wholesale power transactions other than allrequirements service: [18] Capacity charge expenses and revenues from capacity contracts shall be included in base rates. Energy charge expenses and revenues from capacity contracts, and all expenses and revenues from opportunity contracts and interchange agreements, shall be included in the fuel charge. A capacity contract shall be defined as a contract which fixes the amount of power to be exchanged, in megawatts or as a percentage of the output of a generating unit, for a period in excess of one year. All other power transactions, except all-requirements service, shall be deemed to occur under an opportunity contract or interchange agreement. Capacity charge revenues or expenses incurred under a capacity contract which is in effect for less than twelve months following the issuance of a rate order shall be included in the fuel charge until: **[*75]** (I) they are moved into base rates, in the case of a contract signed since the rate case; or (2) the contract expires, in the case of contracts which terminate within twelve months following the issuance of the rate order. This treatment thus allows for quarterly adjustments in the fuel charge. [19]

The treatment of costs and revenues from wholesale power transactions under this standard will neither penalize companies which enter into cost-effective purchases nor provide incentives to companies to engage in purchases and sales which are uneconomic for the ratepayers but may increase profits to the company because of rate-making treatment. We expect companies to be mindful of their responsibility to provide power at the lowest possible cost, and thus to recognize their duty to continue actively seeking purchases and sales which reduce costs. Further, as with our treatment of all-requirements service expenses, this treatment allocates costs between base rates and fuel charge rates in a manner which is more representative of the actual costs incurred.

The record in this case does not contain enough information to allow us to determine capacity charge revenues and expenses under capacity **[*76]** contracts, as defined herein, during the test year. To move WMECo toward the standard treatment of power contract revenues and expenses established in this case, we will allow adjustments which reflet known and measurable changes to WMECo's test-year-costs. These adjustments will remove the capacity charge revenues associated with capacity contracts which have expired since the test year. Further, the department requires the company to include in its fuel charge the retail portion of all expenses and revenues from all wholesale power transactions, adjusted by the amount, per kilowatt-hour, included in base rates. The base rate amount shall be calculated as the net retail amount of all wholesale power transactions, as allowed in this order, divided by the retail kilowatt-hours sold during the test year. The company is ordered to file with the department such a calculation in advance of its next fuel charge filing. We note that the treatment allowed in this case is similar to the tracking clause suggested by the attorney general and WMECo. This treatment will only be in effect until WMECo's next rate case, however. After that time WMECo expenses and revenues will be subject to the standard **[*77]** treatment described above. Therefore, we order the company to file its next rate case in conformance with this standard.

The company's witness testified that five major NU capacity contract sales that were in effect for at least a portion of the test year have now expired or will expire during the rate year. The amount of the revenue loss from one of them, the three-megawatt contract-with Middleborough gas and electric department, is unclear. The expiration of the other four contracts will result in a loss of $ 9,242,000 to NU compared to test-year capacity contract capacity

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[18] See Re Eastern Edison Co. (1982) D.P.U. 1130, for the department's treatment of wholesale expenses under all-requirements service.

[19] Missing in original copy.

charge revenues. After adjustment for WMECo's share of these NU revenues, WMECo's retail adjustment for NU's loss of these four contracts is $ 1,477,000. This reduces the company's pro forma cost of service by $ 630,000.

J. *Transmission Contract Revenues and Expenses*

[27] The company has requested adjustments to test-year transmission contract revenues and expenses. Specifically, it has requested adjustments to decrease revenues by $ 66,000 and to increase expenses by $ 37,000. Transmission revenues arise when other companies pay WMECo for transmission services, and are accrued in Account 456, other electric revenues. The transmission expenses **[*78]** referred to here are those in Account 565, transmission of electricity by others.

The company argues that the proposed "transmission expense and revenue adjustment is closely linked to the adjustment for capacity revenues and expenses." It essentially relies upon its argument with respect to the adjustment proposed for contract power sales and purchases to support the adjustments to transmission revenues and expenses.

The attorney general, following his argument with respect to contract power sales and purchases, maintains that the proposed adjustment for transmission revenues should be denied. Transmission expenses, he argues, should be removed from base rates completely and included in the fuel charge. He cites *Re Boston Edison Co. (1982) 46 PUR4th 431*, where the department found that certain transmission costs were similar in nature to the transportation expenses for fuel, and thus recoverable through the fuel charge. He also cites *Re Commonwealth Electric Co. (1982) 47 PUR4th 229*, and *Re Cambridge Electric Light Co. (1982) 48 PUR4th 32*, where the department denied proposals to include Account 565 expenses in base rates.

The coalition, also following its argument with respect to contract power sales and purchases, argues that the proposed adjustments for transmission revenues and expenses should be denied in **[*79]** full.

We agree with the parties that the treatment of transmission revenues and expenses should parallel the treatment of contract power sales and purchases. Our review of transmission revenues and expenses convinces us that, since they are usually tied to particular contracts or agreements, these revenues and expenses are amenable to the same standard treatment allowed for contract power revenues and expenses. We therefore establish the following standard: Revenues and expenses from all contracts for transmission of capacity -- that is, contracts which fix, in megawatts, the amount of power to be transmitted for a period in excess of one year -- shall be included in base rates. The revenues and expenses arising from all other contracts for transmission services shall be included in the fuel charge. Revenues and expenses which result from contracts for the transmission of capacity which are in effect for less than twelve months following the issuance of a rate order shall be included in the fuel charge until: (1) they are moved into base rates, in the case of a contract signed since the rate case; or (2) the contract expires, in the case of contracts which terminate within twelve **[*80]** months following the issuance of a rate order.

As with contract power sales and purchases, there is not enough information on the record to allow us to implement the standard here. There is also no clear evidence regarding which transmission contracts have expired since the test year, so we have no known and measurable basis for making any adjustment. Therefore, we deny the company's proposed adjustments in full. Accordingly, cost of service must be reduced by $ 103,000.

The department requires the company to include, in its fuel charge, the retail portion of all expenses and revenues from all contracts for transmission service, adjusted by the amount, per kilowatt-hour, included in base rates. The base rate amount shall be calculated as the net retail amount of all transmission expenses booked to Account 565 as allowed in this order, less the contract transmission revenues booked to Account 456 as allowed in this order, divided by the retail kilowatt-hours sold during the test year. The company is ordered to file with the department such a calculation in advance of its next fuel charge filing. Further, the company is ordered to file its next rate case in conformance with the **[*81]** standard treatment for transmission expenses and revenues established above.

K. *Inflation Allowance*

[28-30] The company has requested an inflation allowance of $ 2,558,000. This request is based upon an inflation factor from the midpoint of the test year to the midpoint of the rate year of 8.84 per cent and a residual operation and maintenance ("O&M") expense base of $ 28,939,000 (including company revisions to nuclear refueling outage expense). The company used the gross national product implicit price deflator ("GNPIPD") to calculate the inflation factor.

Warren Hunt, the company's witness on the calculation of the proposed inflation allowance, testified that the company's filing met the department's requirements as established *in Re Commonwealth Electric Co. (1982) 47 PUR4th 229*. However, the company's initial inflation allowance filing was deficient in three respects. First, the company failed to provide the department with a comparison of the historical change in the company's residual O&M base with the change in the GNPIPD. Second, the company did not provide the complete government document containing the historical GNPIPD values. Finally, the historical residual O&M base that the company did provide contained only four years of data, **[*82]** with wholesale figures for the period 1978 through 1981, and retail figures for the test year, making an historical comparison impossible. The company was notified of these shortcomings during the hearings and modified its filing, but it was not until quite late in the hearing schedule that the company's inflation allowance filing met the requirements established by the department.

Because the company's initial filing was deficient, both the attorney general and the coalition have argued that the company's request for an inflation allowance should be denied in full. The attorney general argues that the company's lack of compliance should bar it from collecting an inflation allowance, and that the department has strong precedent for such action in Re Colonial Gas Co. (1982) D.P.U. 1125. The coalition argues that intervenors should not be forced to search through a filing in order to determine whether it complies with the department's requirements. The coalition fears that allowing the company initially to file as little information as possible and to modify the filing only when its shortcomings are noted by the department or intervenors will encourage other utilities to do likewise. **[*83]** Consequently, the coalition asks that the company's requested inflation allowance be denied in its entirety.

The company maintains that it should not be denied an inflation allowance. The company concedes that it first submitted insufficient material, but the filing has now been modified so that it meets all of the department's requirements. According to the company, the modification of the initial filing was done as quickly as possible, and all parties have had enough time to review the new material. Since the filing is now complete, and since no intervenor argues that it is not, the company urges that its inflation allowance not be denied.

The department recognizes that, in preparing filings for a rate case proceeding, the company must adhere to a number of requirements and regulations, and occasionally a filing will be made which does not completely conform to the department's requirements. However, the company knew that its inflation allowance filing was deficient before December 7, 1982, yet it waited until the December 7th hearing, when the deficiencies were noted by the department, before addressing the matter. After the company submitted a modified filing on December **[*84]** 30, 1982, the department had to request additional information to make the inflation allowance filing truly complete. More time than is usually necessary, therefore, was spent on examining the filings and questioning the company's witness. This problem might have been averted had the company followed the department's requirements set forth in D.P.U. 956.

Although the department agrees with the coalition's argument that the company's delay in submitting a correct inflation allowance filing was a burden on the hearing process, we do not find that in the current case the inflation allowance should be denied. The company modified its initial filing so that all parties were given a chance to review it and question the company's witness. Also, the modified filing contains all of the information necessary for the department to determine the validity of the company's request. In the future, however, the company will be expected to make a complete initial filing in order to qualify for an inflation allowance, and the department will not undertake extensive requests such as these to ensure compliance.

The company has included a revised nuclear refueling outage expense for Millstone I of **[*85]** $ 1,014,000 in its residual O&M expense base for purposes of calculating the inflation allowance. The Millstone 1 refueling outage was completed after the test year (November, 1982), and Millstone 1 will not need another refueling outage for at least sixteen months, well past the end of the rate year. According to department policy, the company normalizes or levelizes the refueling costs for Millstone 1 and is allowed to recover twelve-sixteenths of the refueling outage expense each year (this assumes that the time between Millstone 1 refueling outages is sixteen months). The $ 1,014,000 that the company seeks to include in its residual O&M base represents the normalized expense associated with the last Millstone 1 refueling outage.

Both the attorney general and the coalition assert that the normalized expense for the Millstone 1 refueling should not be included in the company's residual O&M base. The attorney general argues that the company will incur no additional refueling expense for Millstone 1 during the rate year, and consequently will not experience any escalation of these expenses. The coalition points out that the company is allowed to collect the full cost of a nuclear **[*86]** refueling of Millstone 1 albeit over sixteen months instead of twelve.

The company claims that the refueling outage cost should be included in the residual O&M base for calculating the inflation allowance because the normalization of the refueling expense adjusts the company's cost of service only for the historical level of the refueling expense, and does not account for any increase caused by inflation.

As mentioned earlier, the department's treatment of scheduled nuclear outages allows the company to recover the periodic, recurring expenses associated with such outages on a normalized basis. The cost of the last completed scheduled nuclear outage is used as an indicator of what the next outage will cost, and, on a normalized basis, is included in the calculation of base rates. The costs associated with a scheduled nuclear outage are large enough to warrant a separate cost-of-service adjustment, and, on that basis, should not be included in the residual O&M expense base. In addition, since the scope of work during a scheduled outage, and thus the total costs, can change dramatically from one outage to the next, an adjustment for inflation is inappropriate. The change in the **[*87]** scope of work from one outage to the next has a far greater effect on the outage costs than changes in price levels.

Therefore, the department finds that $ 525,000 of normalized nuclear scheduled outage expense shall not be added to the company's residual O&M expense base. We also must remove $ 1,294,000 in Millstone 2 nuclear refueling outage expense included in the company's residual O&M expense base. Finally, nuclear refueling outage expense for Connecticut Yankee is included in Account 555, purchased power, and since purchased power will be removed from the residual O&M expense base, no adjustment for outage expense related to Connecticut Yankee is necessary.

The department has elsewhere in this order established a treatment for purchased power and certain transmission expenses which allows variations from the test year to be accounted for in the fuel charge. Thus, the $ 4,534,000 of purchased power expense, and $ 53,000 in transmission expense, which remain in the residual O&M expense base must be removed. The department has also removed the Hydro-Quebec feasibility study expense from test-year cost of service. Thus, $ 114,000 in Hydro-Quebec feasibility study expense shall **[*88]** be removed from the residual O&M expense base.

As described in the bad debt section of this order, the department believes the level of uncollectible expense in a given year is relatively unrelated to the revenues in that year. Thus, it is inappropriate to increase test year uncollectible expense by a percent age increase in revenues or for any increase in inflation. Therefore, we find the total test-year amount of $ 1,326,000 in uncollectible expense must be removed from the residual O&M expense base.

As mentioned earlier, the company's initial filing did not contain a comparison between the historical growth of the GNPIPD and the residual O&M base. On December 30, 1982, the company submitted a revised Schedule S-36, containing such a comparison, which was entered into evidence over intervenor objections. This revised schedule shows that, over the five-year period, calendar years 1977 through 1981, the company's residual O&M base increased somewhat more, on an annual compound basis, than the GNPIPD (9.37 per cent versus 8.71 per cent). As a result, the company has requested an increase in its residual O&M base equal to the full projected increase in the GNPIPD.

The attorney **[*89]** general opposes granting the company the full projected increase in the GNPIPD. He points out that the annual compound increase in the company's residual O&M base is greater than the GNPIPD only for the period 1977 through 1981, and if any other, shorter, period were taken the result would be the opposite. Consequently, the attorney general has proposed that the department use an average of the ratio of the annual compound increase in the residual O&M base to the GNPIPD for the 1979 through 1981 period. This average results in a fraction of 0.49, meaning the company would receive an increase in its residual O&M base equal to 49 per cent of the projected increase in the GNPIPD.

The company contends that since the department has a clear policy of using five years of data to compare the increase in the residual O&M base with the GNPIPD, the department should continue to use five years of data in calculating the allowed increase in the residual O&M base. Also, according to the company, five years of data best reflects the historical growth in the company's residual O&M base.

The following table shows the relationship, in the form of a ratio, between the annual compound percentage **[*90]** increase in the company's residual O&M base and the GNPIPD for five periods, each of which ends in the test year. Unlike the attorney general's comparison, the test year is used as the terminal year for all periods because it provides the most recent O&M expense experience.

COMPOUND ANNUAL PERCENTAGE CHANGE

[SEE TABLE IN ORIGINAL]

As the table indicates, the ratio of the annual compound percentage increase in the company's residual O&M to the GNPIPD varies from a low of 0.39 in the 1979 calendar year/test-year period to a high of 1.08 in the 1977 calendar year/test-year period. The average ratio value for all five periods is 0.83. Although, as the company has pointed out, the department requires utilities to supply five years of data for comparing increases in residual O&M expenses to the GNPIPD, we have not generally used five years of data to calculate the historical relationship between residual O&M expenses and the GNPIPD. As the attorney general has indicated in his reply brief, the department on numerous occasions has used less than five years of historical data to calculate the relationship. In fact, the department has generally used three or four years of data for **[*91]** this purpose.

The department finds it appropriate, in order to provide consistency of treatment and predictability, to establish a standard method of determining the historical relationship between the increase in residual O&M expense and the increase in inflation for use in calculating the inflation allowance.

The department agrees with Mr. Hunt that more recent data presents a better indication of what the relationship between the increase in residual O&M expenses and the increase in the GNPIPD will be in the near future. Thus, more recent years should be given more consideration in the standard method. Yet, based upon this case and our review of the data in previous cases, it is clear that the relationship may be a volatile one. This argues for using more years rather than fewer in the standard method so that aberrations will be smoothed out. Therefore, the standard method shall be to use the average of the ratio of annual compound increase in residual O&M expenses to annual compound increase in the GNPIPD over five periods. Each of the five periods will begin with a calendar year and end with the test year, will be at least twelve months long, and will be separated from the **[*92]** other periods by 12-month intervals. The five years' historical data, plus the test year, will be used to establish the five periods.

This method weights recent experience more heavily while smoothing out aberrations by using a longer period than heretofore. Thus, it addresses the primary considerations mentioned above. We adopt this method for use in this case and in future cases. Here it resists in an historical relationship between the increase in residual O&M expenses and the increase in the GNPIPD of 0.83.

The company has used the forecasts of quarterly GNPIPD developed by Data Resources Incorporated ("DRI"), to calculate the requested inflation allowance, and has submitted, as a late filed revision, an update to its quarterly GNPIPD forecast. Since this is the most recent projection available from DRI, it will be used by the department to recalculate the proposed inflation allowance. This recalculation, which can be seen on the following pages, results in an inflation factor of 7.31 per cent. This factor is multiplied by the residual O&M expense base of $ 22,372,000, calculated as shown on the following page, and results in an inflation allowance of $ 1,635,000 ($ 1,203,000 **[*93]** for operations expense, $ 432,000 for maintenance expense), which we find appropriate.

TEST-YEAR RESIDUAL O&M EXPENSE BASE

[SEE TABLE IN ORIGINAL]

1. Compound annual percentage change in residual O&M and GNPIPD for five periods.

	Residual O&M	GNPIPD
1977-Test Year	9.20	8.55
1978--Tost Year	7.40	8.88
1979--Test Year	3.50	8.98
1980--Test Year	7.08	8.76
1981-Test Year	7.85	7.39

2. Ratio of compound annual per cent change in residual O&M to GNPIPD for five periods.

	Ratio
1977-Test Year	1.08
1978-Test Year	0.83
1979-Test Year	0.39
1980-Test Year	0.81
1981-Test Year	1,06
Average	0.83

3. The average ratio of the compound annual percentage change in residual O&M to the GNPIPD is 0.83; therefore WMECo shall receive 83 per cent of the amount of the projected increase in the GNPIPD.

4. Gross national product implicit price deflator index value at the midpoint of the test year:

Index Value November 15, 1981 201.55 (U. S. Department of Commerce)

Index Value February 15, 1982 203.68 (11. S. Department of Commerce)

Index Value December 31, 1981 202.61 (Interpolated; compounded monthly)

4. Gross national product implicit price deflator index value at the midpoint of the rate year:

Index Value **[*94]** August 15, 1983 218.20 (Data Resources Inc.)

Index Value November 15, 1983 220.90 (Data Resources Inc.)

Index Value October 31, 1983 220.45 (Interpolated; compounded monthly)

5. Increase from the midpoint of the test year to the midpoint of the rate year: 8.80

6. Increase to be applied to WMECo's residual O&M expense base: 7.31

7. Test-year level of residual O&M expenses; 22,372

8. Inflation allowance: 1,635

L. *Water Heater Rental Programs*

[31] The company began renting water heaters to its customers in the early 1960s in order to promote growth in electric use. The revenues and expenses from the rental program are included in the company's cost-of-service calculations, and the allocated cost-of-service study shows this program as a separate column under the residential class. The company has not increased rental rates since 1978, but Dr. Overcast testified that it was planning to increase these rates on April 1, 1983. The higher rates will increase the revenues from rental water heaters by $ 306,000, or 36 per cent. This amount has not been included by the company as an adjustment to revenues.

The attorney general argues that maintenance of the program at a lower than average rate **[*95]** of return "constitutes a totally unjustified cross-subsidization of WMECo's water heater rental customers by other customers of the company." This should be corrected, according to the attorney general, by pro forming into the company's revenues an adjustment of $ 474,000. This figure was derived from Record Request AG-23, which included a test-year actual cost-of-service study and a calculation of the earned rate of return on water heater rentals using a method requested by the attorney general.

The company argues against any adjustment for the water heater rental program. First, it points to the actual test-year figures of Record Request AG-23, which show that with a revenue normalizing adjustment for the April 1st increase the rate of return for water heaters is 12.5 per cent, close to the rate of return sought by WMECo.

In several recent cases the department has found that water heater rental customers should pay the full cost of serving them. We note that the increased fees are required in order for the water heater rental program to earn close to the system rate of return. It is appropriate, therefore, to adjust test-year revenues by $ 306,000.

M. *Property Tax Expense*

The company incurred **[*96]** $ 12,755,000 in property tax expense during the test year. Western Massachusetts Electric Company's initial filing contains an estimated retitletion in test-year property tax expense of $ 2,666,000. According to standard department practice, the record was left open for the company to submit its most recent actual property tax bills. On April 26, 1983, WMECo submitted a late filed exhibit which reflects 1982 actual property tax bills for a number of the municipalities in which the company pays taxes. For the municipalities from which the company stated it had not yet received active 1982 property tax bills, it used actual 1981 property taxes. That exhibit indicates that the company has incurred a $ 688,000 reduction to test-year property tax expense. In response to an inquiry by the department, on April 29, 1983, the company informed the department that four additional bills had been received from Springfield, Amherst, Ashfield, and Easthampton, further reducing the actual 1982 property tax expense by $ 1,507,000. Accordingly, test-year cost of service has been reduced by $ 2,195,000.

N. *Conservation*

[32-35] Western Massachusetts Electric Company first sought to include in its cost of **[*97]** service expenses connected with its conservation efforts in Re Western Massachusetts Electric Co. (1981) D.P.U. 558. However, the expenses the company proposed to include were projected. Therefore, the department denied the company these expenses on the ground that the costs were speculative and did not constitute a known and measurable change to the company's test-year cost of service. Western Massachusetts Electric Company subsequently made certain expenditures on conservation programs and accumulated these amounts in a deferred account.

In its next rate case, Re Western Massachusetts Electric Co. (1982) D.P.U. 957, the company requested reimbursement for the amounts accumulated in the deferred account and requested funds for future conservation programs based on projected expenses for the coming year. The department, in D.P.U. 957, reviewed the company's deferred conservation expenses and allowed amortization of those expenses which were found to be appropriate. The amount of allowed deferred expenses was $ 639,000 and the department permitted the company to recover this amount over three years ($ 213,000 per year). The department also found that a portion of the deferred conservation **[*98]** expenses did not warrant recovery. In addition, the department permitted the company to recover $ 838,000 in projected costs for continuation and expansion of its conservation programs.

In the current case, the company projects conservation expenditures of $ 819,000 for the coming year, excluding payroll costs for personnel hired before July I, 1982. This represents an increase of $ 726,000 over the $ 93,000 spent in the test year. The payroll expenses incurred for conservation programs in the test year were not specified by the company and, while they cannot be determined exactly from the record in this case, are significant. The personnel amounts are included within other payroll expenses in the company's filing, which have been adjusted for known and measurable changes. The company also has included in its proposed cost of service $ 213,000 for amortized program costs, pursuant to the treatment allowed in D.P.U. 957. Finally, the company requests approval for, but does not include in its proposed cost of service, $ 80,000 for "enhancements" to the present company programs. These "enhancements" are new programs or modifications to the eight programs the company pursued in the **[*99]** rate year.

The intervenors generally support the company's proposed conservation program. The EOER supports it, subject to continued program monitoring and evaluation. The coalition supports the program as proposed by the company. FCAC would eliminate or reduce funding for three programs and augment funding for one program, thus reducing the company's recovery for proposed rate year expenses by $ 76,500. FCAC urges approval of the remainder of the company's programs even though the "absence of any cost/benefit [sic] makes it difficult to properly evaluate the existing program and virtually impossible to evaluate the proposed program [additions]."

In D.P.U. 957, the department expressed reservations concerning the manner in which the company had presented its conservation program to the department. There, we stated that "[w]e are concerned that the company did not attempt a cost-benefit analysis of these programs before instituting them, and disappointed that it has not provided a better documented analysis of the long-run benefits and costs to date. . . . Evidence on the record shows that for nonparticipants, in the short run, the costs of the program will exceed the benefits." **[*100]** D.P.U. 957. Nontheless, the department approved most of the company's programs, saying ". . . the programs are short lived and of an experimental nature. If we were to reject out of hand all innovative programs. . . there would be little likelihood that the data which could prove their effectiveness would ever be collected." Id., D.P.U. 957.

The department also ordered the company to "report to the department at three-month intervals from the date of this order on the quarterly and aggregate expenditure levels and participation rates in each separate part of the total program. In addition, the company shall, in a timely fashion, present the department with a comprehensive analysis of the costs and benefits of the program for the twelve months following this order." D.P.U. 957. The twelve months following the order in D.P.U. 957 ends May, 1983.

In D.P.U. 957, the department outlined the type of information needed to evaluate the reasonableness of conservation investments.

The department, in determining whether a conservation program should be supported by ratepayers, will consider such factors as the following:

(1) Cost-benefit analysis;

(2) The existence or degree of **[*101]** subsidization of participants;

(3) Whether the program is innovative, providing new information or approaches. Id., D.P.U. 957.

As FCAC indicates, the company provides little support in this case for its projected adjustment of $ 726,000. Western Massachusetts Electric Company's second-and third-quarter reports, filed in conformance with the reporting requirements of D.P.U. 957, compose the bulk of information submitted regarding program expenses and activities. The company acknowledges that some of the quarterly program budgets were underspent and others overspent, but it justifies equivalent funding or expanded budgets for the rate year based on late starting dates, insufficient customer incentives to reach projected participation levels, or greater than expected customer response and program costs. Western Massachusetts Electric Company supports the new program proposals with a brief description of each and an unsubstantiated estimate of savings.

Two issues need to be addressed regarding the company's conservation expenses: (1) the company's responsibility for justifying conservation expenditures, and (2) the appropriate rate-making treatment of conservation expenses. **[*102]**

As a general matter, the department finds that a utility company must consider the potential impact of conservation and load management strategies as an integral part of its power planning process. In particular, a company is under the same obligation to justify conservation investments as it is to justify power supply investments. In considering the reasonableness of Fitchburg Gas and Electric Light Company's involvement in the Seabrook nuclear project, the department stated that a utility company has an obligation to include in its ongoing review of power supply projets ". . . the feasibility and cost of alternative sources of power currently available, or expected to be available to the company, that might replace the company's originally planned investment, including but not limited to other power supply options such as cogeneration facilities, municipal solid waste energy facilities, hydroelectric capacity both domestic and foreign, as well as demand strategy options such as conservation and load management." (*52 PUR4th at p. 237*.) It is the company's responsibility to forecast future load and to select the combination of supply, conservation, and load management options that results in the lowest **[*103]** long-run cost of electricity.

Thus, in a utility's review of power planning, we would expect an analysis of the appropriate level of conservation to take into account, at a minimum:

(1) an estimate of price-induced conservation without utility-sponsored programs;

(2) the break-even threshold between conservation-load management options and the most cost-effective supply options without conservation;

(3) the impact of various levels of conservation investments on the company's revenues and the cost of electricity; and

(4) the impact of variations in inflation, discount rates, rate of customer load growth, elasticities of demand, and other uncertainties of the optimum mix of options.

It is also incumbent on a company to document this review process so that it can demonstrate the prudence of its actions.

In selecting specific conservation programs to achieve the appropriate level of conservation, the utility is likewise under an obligation to consider and compare all reasonable conservation measures. To this end, there are several economic tests that could be considered. One such standard is the "no-losers test."

The no-losers test measures the impact on the nonparticipating **[*104]** customers who share the cost of a particular conservation program but receive no direct benefits in terms of reduced kilowatt-hour consumption. Nonparticipants may, however, receive benefits in the form of future reductions in electricity prices. Thus a conservation program could pass the no-losers test only if the company's decrease in average cost per kilowatt-hour due to avoided capacity costs and reduction in marginal fuel costs is greater than the increase in cost per kilowatt-hour due to program costs and reduction in kilowatt-hour sales from conservation. The no-losers test ensures that the company spends only that amount on conservation which equates program costs with life cycle savings measured in average cost per kilowatt-hour.

While this test is an important criterion by which to judge conservation investments, the department recognizes that there may be unquantifiable benefits from conservation investments that supersede strict adherence to the no-losers test. For instance, some conservation and load management investments may be made in small increments with almost immediate benefits to customers. Consequently, conservation investments may allow a company to adjust **[*105]** to unforeseen events more readily than power supply projects. Further, conservation and load management options lend diversity to a company's system that, in turn, increases reliability and reduces overall risk.

We also recognize that companies have considerably less experience with conservation and load management programs than with power supply investment. For that reason, there is substantial research value in test marketing different program designs to gain experience in predicting customer response, to monitor actual costs and savings, to compile a statistically reliable data base on conservation impacts, and to develop the qualified staff needed to ensure good program design and execution.

Turning to the present case, the department will allow the company to include the $ 93,000 test-year conservation expenses in its cost of service, as well as $ 213,000 in amortized costs and the considerable level of personnel costs included in the test-year payroll. The department will not permit the prospective amount of $ 726,000 to be included in cost of service because this amount is speculative. The department's decision represents a reduction of $ 726,000 to the company's pro forma **[*106]** expenses.

The department wishes to make clear the company's obligation to present much more detailed information in future requests for conservation funds in order to justify the continued inclusion of test-year amounts. Future conservation programs must be tied to test-year expenditures and presented with proper documentation and justification. The department directs the company to specify how test-year funds were used, including how much was spent on each program and how much the personnel costs were in total and on each program. The company also must explain (1) why the particular level of conservation investment was selected compared to alternative supply scenarios, (2) why the individual conservation programs selected were chosen over other possible conservation measures, and (3) how each conservation program is designed to ensure sound data collection, proper monitoring of results, and continuing program evaluation. IV.

IV. *Rate of Return*

Joseph F. Brennan, president of the consulting firm Associated Utility Services,

Incorporated, testified for the company on its cost of common equity. Mr. Brennan asserted that if WMECo's common stock were publicly traded, a 17.63 per cent return **[*107]** on common equity would be necessary to bring its market price up to book value. Adjusting this return for issuance and selling expenses, he estimated that an 18.5 per cent return on common equity was required. In his oral testimony offered several months after his prefiled testimony, the witness reduced his recommended return on common equity to 17.5 per cent, to reflect the drop in interest rates which had occurred since his prefiled testimony.

A. Gerald Harris, a vice president of Associated Utility Services, Incorporated, testified orally on certain statistical regression analyses he performed for Mr. Brennan. Those statistical results were referred to by Mr. Brennan in his prefiled testimony.

Charles W. King, vice president of the economic consulting firm Snavely, King & Associates, Incorporated, testified on behalf of the Coalition of Western Massachusetts Governments and Institutions regarding WMECo's cost of common equity. Mr. King recommended a 16.2 per cent allowed return on common equity in his prefiled testimony. He was not called upon to testify orally.

A. *Mr. Brennans Testimony*

The estimation of WMECo's cost of common equity (also hereinafter referred to as equity) is complicated **[*108]** by the fact that its common stock is not publicly traded; NU owns WMECo's common stock. Therefore, we must glean proxies for WMECo. These proxies not only must have common stock which is traded publicly, but must also be of a generally comparable investment risk as well. Mr. Brennan chose not to use NU as a proxy for WMECo, since NU is more than six times larger than WMECo in terms of total capitalization.

Mr. Brennan used six broad criteria in his attempt to cull a group of companies with comparable investment risk to that of WMECo. [20] The six criteria were:

(1) Operating electric companies whose bonds are rated A or Baa by Moody's;

(2) Actively traded common stock;

(3) 1981 year-end total capitalization not exceeding $ 1 billion;

(4) 1981 operating revenues greater than $ 100 million which were composed of at least 70 per cent electric sales;

(5) Sales to industrial customers less than 50 per cent of 1981 operating revenues; and

(6) Operation in Massachusetts, the northeastern, Great Lakes, or north central regions.

Numerous other financial and operating statistics were also provided for the comparison companies and WMECo.

Mr. Brennan endeavored to determine **[*109]** whether certain financial and operating factors had any bearing on the investor-required return on common equity. As proxies for the required return on equity, Mr. Brennan used actual earned returns on equity, market-to-book ratios, and earnings-price (E/P) ratios. He reviewed the simple correlation coefficients between each proxy for the required return on equity and each financial or operating factor. Mr. Harris was responsible for these statistical analyses. The correlation coefficient measures the degree to which two variables vary together: The correlation coefficient varies between zero (no correlation) and one (exact correlation). All but one analysis had a correlation coefficient of less than U.3, which Mr. Brennan judged indicated that none of the factors tested had any influence on investor-required returns on common equity. Nonetheless, neither Mr. Brennan nor Mr.

Harris fully embraced the results of these analyses, since there are many factors which simultaneously affect the required return on common equity. Quantifying the effects of such factors is problematic. Mr. Brennan did state that a higher common equity ratio would lower financial risk, thereby lowering the **[*110]** required return on common equity.

Mr. Brennan employed an earnings-price calculation as a general indicium of the required return on common equity. He acknowledged that the earnings-price calculation had certain potential infirmities which rendered the results questionable. For instance, he noted that, if the price of common stock used in the ratio reflects higher or lower expected earnings than the earnings used in the calculation, the result would understate or overstate the current cost of equity. Nevertheless, Mr. Brennan considered the earnings-price calculation to be a good starting point in assessing the cost of equity. The group of comparison companies had an 18 per cent average earnings-price value in 1982.

Mr. Brennan next calculated a discounted cash-flow ("DCF") cost of common equity for his comparison group. The often used DCF model takes as the required return on equity the sum of the required dividend yield and required growth in dividends per share. Mr. Brennan averaged four separate calculations of the dividend yield to arrive at a representative dividend yield. The witness determined a spot dividend yield of 12.2 per cent using the market prices for the comparison **[*111]** companies as of September 7, 1982. He then determined an average dividend yield of 13.3 per cent for the twelve months ending in August, 1982, for which he used indicated annualized dividends and the month-end market prices. He increased both of these by 4 per cent, to 12.7 per cent and 13.8 per cent, respectively, so as to reflect his judgement of investor-required dividends growth of 4 per cent.

The 4 per cent dividends growth estimate is also, in theory, the same percentage growth to be expected of the stock value. Mr. Brennan arrived at a 4 per cent expected growth in dividends by multiplying the most recent five-year average (1977-81) earned return on equity by the most recent five-year average retention ratio of the

[20] Mr. Brennan defined investment risk as the sum of financial risk and business risk. Financial risk is the risk which results from a company's investment in fixed cost, investor-provided capital. Business risk is all remaining risk.

comparison group. The 12.1 per cent average earned return on equity and 25.5 per cent average retention ratio yield a 3.09 per cent product. However, the witness noted that the comparison group had an average market-to-book ratio of 80.8 per cent for the most recent five years. He assumed a 100 per cent linear correlation between the market-to-book ratio and the earned return on equity, and therefore concluded that a 15 per cent earned return on equity would be **[*112]** necessary to achieve a market-to-book ratio of 1.0. He reasoned that investors would consequently expect a 15 per cent earned return on equity in conjunction with a 25.5 per cent retention ratio, so that a 3.8 per cent growth in dividends would be expected. The witness further asserted that the recent increases in authorized rates of return, coupled with lower inflation, would contribute to higher expected earnings and dividends. He concluded that a 4 per cent growth in dividends would be expected. He noted that Value Line-computed historical and projected dividend and earnings growth for his comparison companies corroborated the 4 per cent figure. Accordingly, a 13 per cent yield and 4 per cent dividend growth expectation resulted in a 17 per cent cost of common equity.

Mr. Brennan also undertook a risk spread analysis. He postulated that the common equity cost rate comprises three elements: a bare rent, an inflation premium, and a premium reflecting the greater risk of common stock vis-a-vis debt. Bare rent for the use of utility capital was taken as the amount by which Aaa-rated utility bonds exceeded the GNP deflator. On average, for the 1977-81 period, this bare rent was 2.8 **[*113]** per cent. Mr.

Brennan asserted that, since the bare rent typically falls in a range between 2 per cent and 3 per cent, a 2.5 per cent rate would be the most accurate estimate of the future bare rent.

The next step in the risk spread analysis was to add an inflation risk premium to the bare rent to derive an estimate of long-term utility debt cost rates. Instead, Mr. Brennan subtracted his bare rent estimate from what he projected would be the year-end 1982 average Aaa public utility bond yield. In his prefiled testimony he forecast a 13.5 per cent yield, or an 11 per cent inflation premium (13.5 per cent minus 2.5 per cent). The reason investors demand an inflation premium much larger than current inflation, he surmised, was that inflation in the recent past had been significantly greater than expected.

To ascertain the risk premium required of common stock over debt, Mr. Brennan calculated the difference between the cost of equity as estimated by the DCF model, and the cost of long-term debt, for both the comparison group and those electric utilities with Baa bond ratings (WMECo's bonds are rated Baa) which came from a preselected group of 50 electric utilities. In calculating **[*114]** the cost of equity, Mr. Brennan relied upon Value Line-computed historical and forecasted growth in earnings and dividends. The dividend yield incorporated annualized dividends plus the percentage growth in dividends expected in the next period. To approximate the dividend growth expected in the next period, Mr. Brennan averaged historical and forecasted dividends. He used average monthly market prices in the denominator of the yield.

The estimate of dividends growth (or stock value) the witness estimated as an average of historical and forecasted earnings and dividends growth. Mr. Brennan tested the accuracy of Value Line earnings and dividends forecasts for the period starting in 1977-78, and ending in 1980-81. He found these projections to be 90 per cent accurate on average. In calculating the growth factor, Mr. Brennan included any zero or negative figures found for earnings and dividends.

The results show that the risk spread, as calculated by Mr. Brennan, generally narrows as the cost of public utility long-term debt increases. The risk spreads for the electric utilities whose bonds were rated Baa ranged from a high of 4.2 per cent to 1.4 per cent over the 1978 to March, **[*115]** 1982, time span. The risk spreads for the comparison companies ranged from a high of 3.8 per cent to 1.5 per cent over the same time span. For both groups a risk spread of about 2.5 per cent was found to obtain when bond yields were near 15 per cent, the yield Mr. Brennan expected of Baa public utility bond yields for the end of 1982. Adding the 2.5 per cent spread to the 15 per cent bond yield resulted in a 17.5 per cent cost of equity estimate.

Mr. Brennan adjusted the average of his DCF and risk spread results upward by a 0.375 per cent factor to reflect what he perceived to be the greater risk of WMECo compared to the comparison group. He attributed this greater risk to WMECo's lower interest coverage and quality of earnings. The result is a 17.625 per cent estimate. Mr.

Brennan then adjusted this estimate upwards to 18.5 per cent to reflect costs of issuance and selling expenses of approximately 5 per cent. The witness asserted that an earned 18.5 per cent return would be needed in order to achieve a 1.05 market-to-book ratio. A 1.05 market-to-book ratio would be justified, by his reasoning, since the market-to-book ratio would drop to about 1.0 once issuance and selling expenses **[*116]** were experienced. The 18.5 per cent recommendation was lowered by Mr. Brennan to 17.5 per cent to reflect the decline in interest rates which occurred between the time of his prefiled and oral testimonies.

B. *Mr. King's Testimony*

Mr. King referenced the two Supreme Court decisions, Hope and Bluefield, [21] which set the standards by which a utility's return on common equity should be established. These decisions determined that a utility should be allowed a return commensurate with the returns of other companies having corresponding risks, and that the return should be sufficient for the utility to attract capital.

In contradistinction to Mr. Brennan's testimony, Mr. King argued that the Hope and Bluefield standards do not require that a utility's market-to-book ratio equal 1. He reasoned that, if firms of comparable investment risk have a market-to-book ratio less than 1, then the utility need not have a market-to-book ratio as great as 1 either. Mr. King also argued that the dilution which occurs when common stock is sold at a market-to-book ratio of less than 1 does not damage a utility's investment reputation. The use of interest coverage to determine whether the allowed return on equity is **[*117]** reasonable was criticized as well, since he believed interest coverage to be largely controlled by management.

Mr. King performed a DCF analysis for NU, the company's parent. The dividend yield was taken to be 11.3 per cent. For the dividend component of the yield he utilized a Value Line forecasted increase of eight cents per share, or a 1983 dividend of $ 1.36. A price per share of $ 12, toward the upper end of the range in price during 1982, was used in the denominator.

The estimate of future dividends growth was not as straightforward. Mr. King demonstrated that, if historical dividends and earnings were relied upon solely to project future dividends growth, the resultant projection would range between negative "growth" and 40 per cent growth. The witness therefore relied heavily upon the commonly used product of the earned return on equity and the retention ratio. He theorized that investors should expect NU's earned return on equity to be 14.6 per cent in 1983, and the retention ratio should be expected to return to around 27 per cent after declining below that level for several years. Accordingly, he found 3.9 per cent (rounded to 4 per cent) to be a reasonable expectation **[*118]** of NU's dividend growth, or a 15.3 per cent return (11.3 per cent plus 4 per cent).

To arrive at WMECo's appropriate allowed return on common equity, Mr. King decided that any differences in financial risk between WMECo and NU should be ignored, since VVMECo's capital structure would be different were it an independent electric utility. To assess the business risk differential between WMECo and NU, the witness hypothesized that business risk is largely a function of predictability. He used the coefficient of variation in kilowatt-hour sales and net operating revenue for both companies as a proxy for business risk. The variability in kilowatt-hour sales was similar for both companies, but the variability in net operating revenue was more than 50 per cent greater for WMECo. Admitting the difficulty of quantifying the impact of this risk differential, the witness used the same risk adjustment which Mr. Brennan used in WMECo's last rate case as an estimate of the relative risk differential between NU and the average utility, or 0.6 per cent. Accordingly, he recommended a 15.9 per cent return.

The witness supported his DCF result by arguing that his proposed reduction of the 17 per **[*119]** cent return on equity allowed in WMECo's last rate case to 15.9 per cent was reasonable, given that bond yields had declined

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[21] *Federal Power Commission v Hope Nat. Gas Co. (1944) 320 US 591, 603, 51 PUR NS 193, 88 L Ed 333, 64 S Ct 281*; *Bluefield Water Works & Improv. Co. v West Virginia Pub. Service Commission, 262 US 679, 692, 693*, PUR1923D 11, *67 L Ed 1176, 43 S Ct 675*.

approximately 4 percentage points below the levels which occurred over the period during which the company's last rate filing was decided. He asserted that equity return requirements had not declined as much as bond return requirements, since the relative risk of bonds decreases as inflation and interest rates decline.

Mr. King showed that Mr. Brennan's adjustment to the allowed return on equity would result in a recovery by WMECo of an amount several times the actual expenses of the company's proportion of NU's 1981 and 1982 common stock issues. He proposed a 0.3 percentage point addition to his 15.9 per cent return, or a total of 16.2 per cent.

C. *Analysis of Mr. Brennan's Testimony*

Mr. Brennan has selected six electric utilities which are characterized by investment risk somewhat similar to that of WMECo. He drew attention to WMECo's lower common equity ratio, lower interest coverage, and lower quality of earnings, which indicate greater investment risk, all else held equal. The financial and operating statistics which were presented appear to demonstrate that WMECo is indeed slightly **[*120]** riskier than the comparison group. This apparent difference in risk is lessened by WMECo's superior common dividend coverage. However, quantifying the relative risk differential, and converting that relative risk differential into a differential in the required return on equity, is a labyrinthian task. Mr. Brennan and Mr. Harris began to attempt such a quantification, but stopped short before obtaining any meaningful results. The next step could have been a multiple linear regression. If care is taken that the crucial assumptions behind a multiple regression are not violated, a general idea of which factors have an impact on the required return on equity, and the relative magnitude of those factors, can be estimated. Yet, the room for judgement in a multiple regression model would render the result debatable, and only generally applicable. Despite shortcomings, such a multiple regression analysis could provide useful results.

The first technique of estimation, the E/P calculation, was used as a point of departure. Given the difficulties associated with the E/P calculation as discussed by Mr. Brennan, including the fact that market-to-book ratios of the comparison companies were **[*121]** not near 1.0 at the time of his E/P calculation, we attribute little weight to the E/P results.

Mr. Brennan's DCF analysis was balanced in the sense that he considered a number of inputs before arriving at a conclusion. For his dividend yield, he averaged four factors. The witness averaged a recent spot yield, a recent 12-month average yield incorporating indicated annualized dividends, and the two yields which resulted when the two aforementioned yields were increased to reflect a 4 per cent increase in dividends. However, we would attribute relatively less weight to spot yields, in light of the possibility that the spot yield could reflect a temporary market fluctuation. See *Re Commonwealth Electric Co. (1982) 47 PUR4th 229*. We must also consider the general drop in utility dividend yields, including those of the comparison group, during the several months which have" passed since Mr. Brennan's oral testimony.

The dividend growth estimate of 4 per cent is certainly within a range of reasonableness. Furthermore, the assumption of a linear relationship between the earned return on equity and the market-to-book ratio is questionable, in view of the recent rally in the stock market which led to sharply improved utility market-to-book **[*122]** ratios, with little evidence of increased earned returns. Mr. King illustrated that the earned return on equity and the market-to-book ratio have a very low correlation. Therefore, attempting to set a return on equity which would result in a target market-to-book ratio is destined to bring discomfiture. In light of these problems with Mr. Brennan's dividend growth estimate, a dividend growth of slightly less than 4 per cent seems to be an appropriate expectation.

Mr. Brennan's risk spread analysis essentially adds a risk premium to a bond yield to arrive at the cost of equity. The DCF model used in calculating the risk premium relies to a large extent upon Value Line-forecasted dividends and earnings. Although we consider Value Line forecasts of dividends and earnings relevant in the sense that the forecasts are available to the investment community, the extent to which the investment community relies on these forecasts is unknown. Furthermore, we are not able to cross-examine the analysts responsible for the forecasts regarding their assumptions or technique. Accordingly, we derive limited usefulness from any cost of equity estimate which relies significantly on Value Line forecasts. **[*123]** Re Boston Gas Co. (1982) 49 PUR4th 1.

Mr. Brennan's risk spread analysis fails to extricate the purchasing power premium associated with bonds, but theoretically not required of common stocks. Theory holds that fixed-income investments such as bonds offer less protection against higher than expected inflation than do variable income investments such as common stocks. To the extent this theory is true, this purchasing power premium biases upward Mr. Brennan's recommended return on equity. Mr. Brennan was unsure of the theory's validity in light of actual market experience.

Another possible premium which the witness did not explicitly consider is the hypothesized premium for interest rate risk of principal. Interest rate risk of principal refers to the possibility that interest rates may rise, causing the prices on outstanding bonds to drop by the amount necessary to cause the interest rates of those outstanding bonds to rise to the market level. Investors may require a premium on their bond yield to protect against this type of risk, as the witness admitted. The lower the coupon and the longer the maturity, the greater the interest rate risk of principal. Quantification of this possible risk premium, and verification **[*124]** of whether and to what extent a similar risk is associated with common stock, would have increased the accuracy of this risk spread analysis.

Finally, a call premium is commonly included in the interest rate of bonds, to protect against the likelihood that a company will repurchase the bonds when interest rates decline, as the witness acknowledged. The call premium is typically measured as the amount by which the call price exceeds the par value.

The failure of Mr. Brennan's analysis to consider explicitly the aforementioned premiums lends an upward bias to the result. Re Massachusetts Electric Co. (1982) D.P.U. 1133.

The 0.375 per cent premium added to Mr. Brennan's recommended return to reflect what he considered to be the additional risk of WMECo versus the comparison group is clearly no more than an informed guess at what the proper premium should be. Although we agree that WMECo appears to be slightly riskier than the comparison group based on the record, the record does not contain enough information to enable us to ascertain that WMECo is significantly riskier. More importantly, the 0.375 per cent premium was arrived at by a judgement of the effect of the common equity **[*125]** ratio and allowance for funds used during construction (AFUDC) as a percentage of net income ratio on the cost of equity. The attorney general's cross-examination of the witness illustrates that the calculation is overly simplistic, and the witness conceded the difficulty of quantifying the impact on the cost of equity of various factors.

Mr. Brennan adjusted his recommended return for issuance and selling expenses.

We acknowledge that WMECo should be compensated for that portion of NU common stock issuances allocable to WMECo. However, the allowed return on common equity is not the proper vehicle through which a utility should recover these costs. Our responsibility is to allow a return reflecting the return required by investors: Investors' required return does not reflect any adjustment for issuance and selling expenses. Therefore, these expenses should be considered as above the line. See Re Massachusetts Electric Co. (1982) D.P.U. 1133.

D. *Analysis of Mr. King's Testimony*

We agree with Mr. King's position in this rate case of "not taking a position as to the propriety, or lack thereof, of a target market-to-book ratio of 1.0." Mr. King demonstrated that it is overly simplistic to attempt to associate **[*126]** a given earned return on common equity with a certain market-to-book ratio. There are many other factors which have an impact on the market-to-book ratio.

Mr. King's DCF analysis of NU is even-handed. He employed a fair approximation of the expected dividend yield and expected dividends growth in deriving a 15.3 per cent required return on NU's common stock. As with every DCF calculation, there is room for some argument, but the recent volatility in dividends and earnings sets a wide range of returns which could be reasonably expected.

We are concerned, however, that Mr. King has not demonstrated an investment risk comparability between NU and WMECo. Such statistics as those used by Mr. Brennan, including the financial and operating statistics provided in Mr. Brennan's Exhs B-9 and B-10, would have provided a better basis for comparing investment risk. Both witnesses would have had a more solid basis front which to assess comparative investment risk if they had also reviewed such statistics as: projected construction expenditures as a percentage of net income, proportion of generating capacity derived from nuclear power, regulatory climate, and cash-flow adequacy. Moreover, all **[*127]** relevant financial and operating statistics should be reviewed in assessing relative investment risk, including those within the control of the company's or parent's management.

The coefficients of variation in kilowatt-hour sales and net operating revenues (especially the latter) are certainly relevant criteria of relative risk assessment. Nonetheless, Mr. King's sole reliance on these statistics in determining an investment risk differential between NU and WMECo simply disregards too many germane financial and operating statistics. Consequently, we cannot attribute great weight to Mr. King's recommendation.

Mr. King would append 0.3 per cent to the cost of equity calculation, as compensation to the company for issuance and selling expenses. We do not find such an adjustment to be appropriate. Re Western Massachusetts Electric Co. (1982) D.P.U. 957. Our duty is to allow a return which reflects the return required by investors, no more and no less. If investors take into consideration the costs incurred by a company when common stock is issued, then the return which they require on that common stock will already reflect ample compensation for those costs. Therefore, no explicit **[*128]** adjustment for issuance and selling expenses is necessary.

E. *Summary*

[36] We have noted the infirmities in the analyses of both witnesses which cause us to rely only partially upon their recommendations. Of course, because of the inherently judgmental aspects associated with the determination of the cost of equity, not one method is entirely free from criticism. The DCF method has been considered a reliable method for assessing the return on common equity required by investors. It has also been useful to apply a supplemental method, such as a risk premium analysis, to check the DCF result.

A review of the evidence on this record persuades us that a decrease in the company's allowed return on equity is warranted. The general decline in interest rates since the allowance of a 17 per cent return on WMECo's common equity in May, 1982, is irrecusable. The actions which we have taken in this order also serve to reduce WMECo's business risk. We refer specifically to our institution of a mechanism to track capacity purchases and sales (see Section III, *supra*) as well as to improvements made in the company's rate design (see Section VII, *infra*). Although we are unable to precisely quantify the effects of these **[*129]** actions, we find that as a general proposition they will reduce WMECo's business, and accordingly, investment risk. This reduction in investment risk will occur because rates paid by customers will track costs more closely, improving the company's revenue and earnings stability.

In consideration of all the evidence before us, we find a 16 per cent allowed return on common equity should enable WMECo to attract capital at a reasonable cost. In assessing the reasonableness of this return we note that WMECo, in its filings before the Federal Energy Regulatory Commission, considered 16 per cent to be a reasonable allowed return on common equity for the NUG&T. [22]

V. *Capital Structure*

The company has submitted a test-year-end capital structure as of June 30, 1982. A $ 10 million increase in common equity resulting; from a capital contribution provided by NU for VVMECo at the end of 1982 is a known and measurable change, and is therefore allowed. Western Massachusetts Electric Company also adjusted the test-year-end capital structure to reflect a preferred stock issue of $ 35 million on April 12, 1983. The cost of the issue varies quarterly with the rates of U. S. Treasury issues, as approved in **[*130]** D.P.U. 1442. A 12 per cent rate will be in effect for the first two months of the rate year. The cost rate during the following ten months of the rate year must be estimated. The company arrived at an estimate which would comport with D.P.U. 1442, assuming the quarterly rate were set as of April 11, 1983. This rate was 11.19 per cent. A weighted average of these two rates is

[22] We note also that *GL Chap 164, § 94C* provides in part: "Whenever the rates and charges of the affiliated company are regulated by the Federal Power Commission the department shall not establish rates and charges for the investing company which provide a higher return on the investment than that found to be fair and reasonable by the Federal Power Commission."

11.33 per cent, or an 11.72 per cent effective cost. This 11.72 per cent figure is an appropriate cost rate for this issuance of preferred stock, since it will be applied against net proceeds instead of gross proceeds.

A five-year promissory note with principal of $ 30 million has a cost rate which is set at 102 per cent of Chemical Bank's prime rate. An updated exhibit shows the various Chemical prime rates which were in effect from June 1, 1981, to April 15, 1983. The department's policy is to consider the most recent 12-month average interest rate of any variable interest securities to be included in the capital structure of a rate decision. Sec Re Boston Gas Co. (1982) 49 PUR4th 1; Re Eastern Edison Co. (1982) D.P.U. 1130. An average of these rates for the April 16, 1982, through April 15, 1983, period, weighted by the number of days each rate **[*131]** was in effect, is 13.61 per cent. This 13.61 per cent rate will be used in the determination of capital structure, as it appears to be a fair approximation of the applicable rate during the rate year. The capital structure employed for this decision follows:

CAPITAL STRUCTURE ($ 000)

[SEE TABLE IN ORIGINAL]

VI. *The Northeast Utilities Generation and Transmission Agreement*

As an affiliate in the NU system, the company participates in the Northeast Utilities generation and transmission agreement ("NUG&T"). This agreement, which is subject to review by FERC, allocates the expenses and revenues associated with generation and transmission among the various operating companies in the NU system. System generation and backbone transmission are owned not by a separate wholesale affiliate but by each of the system affiliates in its capacity as a separate corporate entity. An affiliate may actually own all, some, or none of any given generation unit. The agreement allocates generation costs among affiliates by imputing to each operating company a cost share in each generating unit which is equal to the ratio of that company's noncoincident peak to the system non-coincident peak. To the extent a company's ownership interest in a particular **[*132]** unit does not equal this ratio, the agreement requires it to buy or sell an amount of the capacity of that unit which would make its actual ownership in the unit equal to the ratio. Energy costs are allocated on the basis of each company's aggregate monthly load in relation to the monthly system load. With the exception of the cost of equity, which is specifically approved by FERC and uniformly applied to every affiliate, all purchases and sales under the agreement arc priced on a monthly basis at the selling company's actual booked costs.

This agreement and its ramifications have been major issues in the company's last three rate cases. The underlying concern has been whether the agreement treats WMECo's ratepayers in a fair and equitable manner. Specifically, the dispute has centered on whether WMECo has, in effect, been subsidizing the other NU affiliates through the operation of the NUG&T.

In the company's most recent rate case, D.P.U. 957, the department ordered WMECo to petition FERC for changes which would eliminate WMECo's admitted cross-subsidization of its Connecticut affiliates. Specifically, the department ordered WMECo to file an amendment to the NUG&T which would **[*133]** allow the common equity component of the carrying charges to be computed in the same manner as the preferred stock and debt components. The department further ordered the company to request in the alternative that, in the event FERC denied the first proposed amendment, the common equity component be increased to 17 per cent. Id., D.P.U. 957. The first proposed change would have structurally eliminated the possibility of the particular cross-subsidization with which the department was concerned; and the alternative change would have temporarily neutralized it. Western Massachusetts Electric Company was also ordered to file with the department by August 1, 1982, a report reviewing different capacity cost allocation methods. Id. D.P.U. 957.

On October 15, 1982, the company filed with the department the allocation report ordered in D.P.U. 957. Western Massachusetts Electric Company appealed the NUG&T portion of the D.P.U. 957 decision to the Massachusetts' supreme judicial court and sought a stay of that portion of the department's order. Following denial of that stay, the company on November 8, 1982, filed an amended agreement with FERC which would have changed the basis upon which **[*134]** the common equity component was calculated so as to take into consideration the changes in cost of equity for each affiliated company in the same manner that other changes in each affiliate's capital structure are considered.

However, the company requested that the amended agreement become effective only after the occurrence of the latter of two events: "(a) the commission's [FERC] final action on this filing (including actions subsequent to judicial review) or (b) final resolution of WMECo's appeal to the D.P.U.'s order of May 28, 1982." Federal Energy Regulatory Commission Docket No. ER-83-114-000. Also, the company's filing did not request the alternative relief as required by the department. Id., Docket No. ER-83-114-000, footnote 3.

On April 6, 1983, FERC rejected the company's amended agreement, finding that the department had no authority to order the company to make such a filing. Federal Energy Regulatory Commission Docket No. ER-83-114-000, April 6, 1982. Federal Energy Regulatory Commission noted that the proper means by which the department may make known its concerns about a utility's wholesale rates is through a complaint brought pursuant to §§ 206(a) and 824(a) **[*135]** of 16 USC, the Federal Power Act.

We remain troubled by the company's failure to respond to the department's concerns about the NUG&T, especially in view of WMECo's recognition of the cross-subsidization problem inherent in the return on capital provision of the agreement D.P.U. 957, p. 90. We refer specifically to the form and content of the company's November, 1982, filing to FERC. The department's order in D.P.U. 957 gave the company fairly broad discretion in drafting its filing. The company seized upon this leeway to tailor a filing that would be most noxious to FERC. We refer particularly to the company's unusual request that the amendment become effective only upon the occurrence of the latter of two events. Furthermore, the company failed to file the alternative amendment ordered in D.P.U. 957, arguing that FERC rules do not permit such alternative filings. To the contrary, FERC recently approved an alternative filing concerning the New England Power Company in Re New England Electric Co. Docket Nos. ER-82-702-000, ER-82-703-000, Dec. 30, 1982 (20 FERC PSir 61,410). The coalition argues that these and other factors indicate bad faith on the part of the company. The filing **[*136]** was certainly drafted in such a way as virtually to guarantee its rejection by FERC.

The department remains concerned that discriminatory treatment of Massachusetts ratepayers may result from the NUG&T. As of this time, the problems inherent in the agreement have not been rectified. We will continue to explore and pursue our options with respect to the NUG&T under state and federal statutes. In light of WMECo's responsibility and obligation to its ratepayers, the department continues to expect the company to make good faith efforts to address these problems as well.

VII. *Millstone 3 Nuclear Project*

Millstone 3 is a pressurized water nuclear reactor being built by NU at a site in Connecticut near Millstone 1 and Millstone 2, two other nuclear power plants. The proposed in-service date for Millstone 3 is mid-1986. Western Massachusetts Electric Company's share of Millstone 3 is 19 per cent of NU's ownership share and 12.65 per cent overall. The total cost of the facility is now estimated by the company to be $ 3,540,000.

FCAC urges the department to recognize that the Millstone 3 construction program poses intolerable risks which must be reduced. FCAC takes the position that the department should **[*137]** find WMECo's continued involvement in Millstone 3 imprudent at the present ownership level, and that it should convene a special proceeding to examine how to implement this finding. In the alternative, FCAC would have the department place a cap on the costs the company's ratepayers are liable for in connection with Millstone 3; it suggests a separate proceeding would be worthwhile to explore this issue.

The company argues that Millstone 3 is needed to "provide electrical requirements of all New England consumers as well as those of the customers of the NU system"; that the Connecticut Department of Public Utility Control recently approved the continuation of NU's investment in Millstone 3; and that in any case there appear to be no buyers of Millstone 3 shares.

The company has not, in this proceeding, requested any adjustments which specifically pertain to the Millstone 3 construction program.

A. *FCAC's Arguments*

FCAC argues that Millstone 3 is likely to have a deleterious effect on WMECo's ratepayers in the long run because: (1) electricity from Millstone 3 will be more expensive than electricity from other sources, and (2) even assuming the construction of Millstone 3 is warranted **[*138]** from the perspective of NU, it is not needed from WMECo's perspective.

In support of the first point, FCAC states that even the most recent company comparisons between the cost of Millstone 3 electricity and replacement energy costs show that from 1986-95 replacement energy costs are five cents per kilowatt-hour less than currently projected Millstone costs. This differential would widen considerably, according to FCAC, if NU were to complete planned conversions of units that are now oil fired to lower cost coal firing.

FCAC also takes the position that the company's estimates for Millstone 3's total cost, capacity factor, and operation and maintenance expenses, are unduly optimistic. FCAC believes that all indications, including the past history of cost escalations of the project, suggest that in four years the cost of the project will be at least 25 per cent higher than the present estimate. FCAC challenges the company's position that once the unit is on line its mature capacity factor will be as high as 70 per cent, contending that a capacity factor of 60 to 65 per cent is more in line with the information on the record. FCAC also takes issue with the company's projected escalation **[*139]** rates for operation and maintenance once the unit is operational, stating that historical operation and maintenance increases at Millstone 1 and 2 are several times higher than what the company projects for Millstone 3.

FCAC contends that its case concerning the relative cost disadvantages of Millstone 3 is demonstrated by NU's inability to sell any of its joint ownership interest in the last two years despite its intent to do so.

FCAC further argues that WMECo does not need the capacity that Millstone 3 represents and cannot afford the Millstone 3 costs. FCAC states that the evidence shows that without Millstone 3 power WMECo will have a capacity reserve margin of 32 per cent in the last year of the company's forecast, 1991, or far more than is needed. Western Massachusetts Electric Company could become independent of oil without Millstone 3, according to FCAC, by converting its West Springfield station to coal-fired generation.

FCAC also argues that Millstone 3 construction costs are putting a "very real strain" on WMECo's financial condition, and that WMECo is being forced to carry a disproportionate amount of the cost and risk in Millstone (19 per cent of NU's share) compared **[*140]** to its share in the NU system (less than 17 per cent). Even a sale of all or a portion of WMECo's share of Millstone 3 (to an outside utility or to its Connecticut affiliates) at a reduced price would be worthwhile by FCAC's calculation.

Finally, FCAC is very concerned that the position put fonvard in this case by the company is really NU's position and that no one within the NU corporate structure pays heed to WMECo's distinct needs.

B. *The Company's Arguments*

The company, in its brief, responds to a number of the arguments made by FCAC and sets forth its own position. First, the company states that the mere fact that past costs estimates for Millstone 3 were exceeded docs not mean that the present estimate will be exceeded, and at present the unit is approximately 60 per cent complete.

Second, the company admits to trying to sell shares in Millstone 3 because of financial constraints and being unable to do so, but claims that the Seabrook nuclear plant construction in Seabrook, New Hampshire, has financially strapped other New England utilities and left them unable to invest in other projects. The company argues that redistributing Millstone 3 ownership shares within the NU companies is not **[*141]** reasonable. The company also argues that there is no evidence on the record that its financial condition is hindering or delaying its coal conversion plans.

Third, the company states that without Millstone 3 "NU system capacity requirements would exceed existing generation capacity in 1991 and the entire New England area would lack' sufficient generating capacity in 1993."

Given the long lead times necessary for constructing and bringing on line major generating units, the company doubts whether any other generating unit could be placed into service to meet NU or New England capacity needs.

Fourth, the company contends that Millstone 3 generation costs will become less expensive than fossil fuel generation in the mid-1990s, and thus the unit will provide a significant economic benefit to consumers for much of its estimated 35-year useful life. The company also takes issue with FCAC's claim that the predicted 70 per cent capacity factor for Millstone 3 is too high.

Finally, the company argues that there is no basis for finding the company imprudent in its handling of the Millstone 3 project, or for finding that a cap should be placed on the project's allowable costs. Furthermore, **[*142]** the company claims that even the institution of a special proceeding concerning the upper limit for the capital cost of Millstone 3 has the potential for exerting a "strong negative effect upon the company's financing costs and [that it] ultimately [would] increase the project cost."

C. *Conclusion*

[37, 38] The company and FCAC take quite different positions on the economic benefits that will flow from the completion of Millstone 3. The company sees Millstone 3 as a unit that will provide needed generating capacity to NU and New England, reduce oil dependence, and supply electricity at lower than fossil fuel rates at some point in the next decade. FCAC believes the unit will not be economic, that it is not called for from the perspective of YVMECo's capacity needs, and that therefore it will simply mean added and unnecessary costs for the company's ratepayers.

In *Re Fitchburg Gas & Electric Light Co. (1983) 52 PUR4th 197*, the department set out a utility's obligations regarding power supply options (*52 PUR4th at pp. 236,237*): "As a general matter, a utility company has a continuing obligation to monitor, review, and assess its participation in a specific power supply project [footnote omitted]. Such an evaluation should occur within the context of the company's **[*143]** general power planning process. We would expect such a review to include, at a minimum: (1) the likelihood of the power supply project's coming on line at the expected time and at the projected costs; (2) the options likely to be available to the company if the power supply project is not operating when scheduled and at the projected costs; (3) the feasibility and cost of alternative sources of power currently available, or expected to be available to the company, that might replace the company's originally planned investment, including but not limited to other power supply options such as cogeneration facilities, municipal solid waste energy facilities, hydroelectric capacity both domestic and foreign, as well as demand strategy options such as conservation and load management; (4) the effect on the financial health of the company given continued involvement in the power supply project; and (5) the effect that continued participation in the project will have on the company's ratepayers. A company also has the obligation to document this review process so that it can demonstrate the prudence of its actions."

The department has investigated nuclear projects in separate proceedings **[*144]** when deemed appropriate, and has also investigated nuclear projects in conjunction with a company's rate proceeding. See Re Boston Edison Co. D.P.U. 19494, Sept. 22, 1981; *Re Boston Edison Co. (1982) 46 PUR4th 431*. The department also has recently declined to open a separate investigation into a company's investment in the Seabrook nuclear project. See *Re Fitchburg Gas & Electric Light Co. (1983) 52 PUR4th 197*. In this case, we are not convinced that this is the proper time to open a separate investigation.

The department does believe that the entire issue of the adequacy of WMECo's review process and the prudence of its decisions concerning its continued participation in the Millstone 3 project -- as distinct from the decisions or participation of Connecticut Light and Power or any other utility -- will be addressed in a future proceeding. We expect WMECo to have sufficient documentation of its review process to demonstrate that it has adequately considered, at a minimum, all of the factors listed above in the language taken from the Fitchburg order, [23] and other factors specific to the company's situation, such as the possible transfer of ownership shares to other NU

[23] See Section III, N, in which we discuss the company's obligation with regard to conservation programs.

affiliates. We expect that all review and analysis will be approached from the perspective of WMECb and its ratepayers **[*145]** and not from the perspective of NU or New England as a whole.

As a general matter, we note that a company's decision to construct a power generating facility does not automatically guarantee that the cost of that facility or any part of the cost of that facility will be recovered through rates. A company must demonstrate the prudence of its investment and that the manner in which it proposes to recover the costs of its investment is reasonable. The questions raised by FCAC have served to highlight WMECo's responsibility to demonstrate, at the time it seeks to recover the costs associated with its investment in Millstone 3, the prudence of its actions.

VIII. *Rate Design*

A. *Introduction*

Since 1981 the company has been advocating changes in its rates designed (1) to bring rates closer to the costs of serving different classes of customers and (2) to convey more appropriate price signals to customers. In D.P.U. 558 the company attempted to reach agreement with some intervenors regarding proposed rate structure changes. When this effort was unsuccessful, the department agreed with the company's and intervenors' request to investigate these rate structure charges in a separate proceeding, D.P.U. **[*146]** 20110-A.

In D.P.U. 20110-A, the department found that the company's load data was adequate to support an allocated cost-of-service study, and that the company's demand allocation methodology was reasonable. However, the company was ordered to remedy the following aspects of the cost-of-service study in the study presented with its next rate case: (1) the definition of customer costs included more distribution costs than had been justified; (2) the company's line loss study was inadequate; when sales were adjusted by estimated line losses 2.4 per cent of generated energy was still unaccounted for. However, finding that these modifications would not cause major changes in the rates of return produced by the cost-of-service study, the department found that study a reasonable basis for revenue allocation. Therefore, the company was ordered to reallocate based on the cost-of-service study an amount of revenue equal to one-half of the increases granted in D.P.U. 558 and D. P.U. 957.

In D.P.U. 20110-A the department also accepted the company's proposal to flatten energy charges so that the price paid for energy (including both the base rate and the fuel charge) would usually equal the **[*147]** marginal energy cost. For the large industrial rate, Rate 35, this change would entail shifting revenue from demand charges to energy charges, resulting in large bill increases to the largest energy users on this rate. The department also found that Rate 21, the optional heating and general service rate, had been a promotional rate and earned a very low rate of return. No parties objected during D.P.U. 20110-A to the proposed closing of this rate and the transfer of its small customers to Rate 20 (small general service) and its large customers to Rate 35. The department approved the elimination of this rate and allowed the company one year to complete the transfer of these customers. In addition, the department directed the company to prepare a proposal for dividing Rate 35 customers according to voltage levels.

Before the D.P.U. 20110-A rates were implemented, Monsanto and Kimberly-Clark filed a motion for reconsideration and partial stay of this order as it related to the redesign of Rate 35. They argued that the modifications to the cost-of-service study ordered by the department would reveal that the restructured Rate 35 would actually overcharge the largest customers on this **[*148]** rate. The department, in response, partially stayed the order in D.P.U. 20110-A, delaying only the redesign of the large industrial rate, Rate 35, in order to give the intervenors time to be heard. The delay in the redesign of Rate 35 had the effect of transferring large Rate 21 customers to a rate substantially different from the rate which had been the basis on which bill impacts had been calculated in the testimony in D.P.U. 20110-A. Thus, former Rate 21 customers experienced substantial increases in their bills.

In the current proceeding, the company submitted several class-allocated cost-of-service studies incorporating the methodological changes required by the order in D.P.U. 20110-A. The study filed with the company's initial case was based on calendar year 1981, and did not divide Rate 35 by voltage level. The original testimony of Dr. Edwin

Overcast, the company's rate design witness, indicated that the company was in the process of completing a test-year pro forma cost-of-service study which could be the basis for dividing the customers served by Rate 35. This supplemental testimony was submitted on December 15, 1982. Additional versions of this cost-of-service study **[*149]** were produced in response to various record requests.

Monsanto and Kimberly-Clark, hereinafter designated as "industrial intervenors," jointly addressed matters of rate design. The industrial intervenors submitted the testimony of Dr. Rosenberg, Mr. Drazen, and Mr. Doyle, and, after Dr. Overcast gave rebuttal testimony, the industrial intervenors submitted surrebuttal testimony by Mr. Drazen.

As noted in Section I, petitioners, representing a number of large Rate 21 customers, were allowed to submit a brief on rate design issues. In their brief, petitioners argue that the unchanged design of Rate 35 resulted in very large bill increases to former Rate 21 customers who were transferred to Rate 35, as a result of D.P.U. 20110-A. They argue that the most equitable treatment of these customers will result from the implementation of a revised Rate 35 with decreased demand charges and increased energy charges.

The major rate design issues which must be addressed in this case are aspects of the company's cost-of-service study, the allocation of the revenue increase, and the redesign of Rate 35.

Before addressing these issues, however, we must note that the company's conduct in **[*150]** this case has been less than exemplary. In particular, we note that the company's original filing was not in compliance with the D.P.U. 20110-A directive to present with supporting data a proposal to divide Rate 35 customers into two or more rate classes. In the future we will not accept a filing which has failed to comply with prior department orders.

In addition, we note that intervenors and the department have been severely hampered in conducting this investigation because of the company's failure to provide timely and accurate information during the course of the proceedings. We refer, for instance, to the two-month delay between the rate case filing and the filing of the test-year cost-of-service study. The industrial intervenors argue that the company's tactics in the rate structure portion of this case require review as a distinct issue. They state that the company's conduct "appears to have been purposefully designed to make meaningful review of, and reply to, the company's case exceptionally difficult."

Without ascribing a motive to the company's actions, we note that it has consistently shown disregard for the intervenors' and the department's need to ascertain the **[*151]** facts relevant to the rate design issues in this case. For example, we would have expected the company to have supplied a test-year cost-of-service study in its initial filing. Further, while the company maintained that it made decisions about revenue allocation based on what classes earned during the test year, it did not provide rate case participants with this information until required to do so. Neither of the studies submitted at the company's initiative contained test-year revenues, pro forma or actual. The company's failure to include a few pages in the original studies showing revenue deficiencies and rate of return based on test-year pro forma revenues resulted in substantial additional work for itself, the intervenors, and the department.

Of even greater concern is the company's tardy correction of its own errors. For example, the industrial intervenors have protested the withdrawal and dilatory replacement of the response for their information request for curves (which they planned to use in their case) showing the relationship between costs and revenues for different sizes of customers on Rate 35. The attorney general was similarly inconvenienced by learning on the first **[*152]** day of Dr.

Overcast's testimony about a significant error in the water heater rental portion of the cost study, which error Dr. Overcast testified the company had discovered at least two weeks previously. Finally, the witness did not give consistent testimony. There were numerous instances of the witness's failing to correct known inaccuracies in his previous testimony until the issue arose in additional cross-examination. Even more disruptive to the case was his responding to a question on the second day of his testimony that the number for the primary Rate 35 revenue target which had appeared in his supplemental prefiled testimony was not accurate. This number had been the subject of considerable discussion during the first day of hearings on rate design issues.

We expect witnesses before the department to exercise greater diligence in testifying accurately and in correcting their own errors than was exercised by Dr. Overcast. Although the information necessary to make rate structure decisions was finally provided, the company's presentation put an unnecessarily heavy burden on intervenors and on the department.

As a general matter, we find that equally important as the **[*153]** company's right to the opportunity to earn a fair return on its invested capital is the customer's right to be assessed a just and reasonable portion of the cost of providing service. By frustrating the intervenors' ability to present a case which may result in significantly different rates than those proposed by the company, the company is in a position to deny customers this right. In the future, the department will not tolerate the type of presentation offered by the company in this case.

B. *The Company's Cost-of-service Studies*

The company's cost-of-service studies complied with the directives of D.P.U. 20110-A insofar as they included the effects of fuel costs and revenues and classified as customer related only service drop and meter costs and customer accounts expenses. In addition, the company submitted a new line loss study, which reduced unexplained losses to less than 0.1 per cent. Because of this compliance, these aspects of the studies' method were not at issue in the present proceeding. The demand allocation method used in the cost-of-service studies was an issue, as was the proper treatment of Rate 35.

1. *The Company's Demand Allocation Method*

[39] The studies which the company entered as exhibits allocated demand-related costs **[*154]** on the basis of a particular version of the average and excess method. Average and excess demand ("AED") allocation methods divide costs between those incurred to meet average demand (the total kilowatt-hours generated in a year divided by the number of hours in the year) and those incurred to meet "excess" or above average demand, and these costs are allocated on the basis of class energy use and excess demand, respectively. The proportion of costs allocated on the basis of energy is determined by the ratio of average demand to excess demand. Thus, the lower the excess demand, the greater the proportion of costs that will be allocated on the basis of energy. Dr. Overcast defined "excess demand" as the difference between average demand and the average of the 12 monthly peaks. He stated that this definition was appropriate because the Northeast system does not have a sharp peak, but rather has monthly peaks which are fairly similar. He asserts that in capacity planning the company must therefore be concerned with more than a single peak month. In addition, he noted that allocating more costs on the basis of energy, which this definition does, reflects the fact that the company in the **[*155]** long run builds power plants to lower energy costs as well as to meet peak demands.

The industrial intervenors argue that the company's definition of "excess demand" is in error and flaws the cost-of-service studies. According to Dr. Rosenberg, under the "standard" AED method the proportion of costs defined as excess is the difference between average demand and the system peak. Thus, he states, the capacity which is needed to meet load above the average demand level would more appropriately be allocated on the basis of class excess demands. Using this method for WMECo would result in allocating 40.8 per cent of demand-related costs on the basis of excess demands, whereas the company's method allocates only 30.7 per cent of these costs on that basis. Dr. Rosenberg argues that Dr. Overcast's method is nonstandard and that it is in conflict with the rationale of the average and excess method. He states that the "significance of the 'excess' demand is that it represents the additional *amount* of capacity needed to meet peaks," and that reducing the "excess" by averaging 12 monthly peaks "implies that the system requires less capacity than it actually does require."

The issue here is not **[*156]** whether the company's or the industrial intervenors' version of the AED is the "standard" one. The question, is, which better reflects cost causation for this company. We find that there is a fundamental flaw in Dr. Rosenberg's argument about the rationale of the AED method. What should be allocated on the basis of excess demand is not megawatts of capacity, but dollars of capacity cost. It has not been demonstrated that the proportion of value of plant used to meet excess demand relative to total plant value is equal to the proportion of capacity needed to meet excess demand relative to total capacity. In fact, it is reasonable to assume that the two will not be equal: The relative value of peaking plant will be less than the relative capacity, because peaking plant is less expensive per megawatt than base-load plant. We find the company's definition preferable to that of the industrial intervenors precisely because it results in a more accurate allocation of costs between capacity and energy. Given the company's current demand and supply configuration, therefore, we find the company's allocation method to be appropriate for the purposes of this case.

2. *The Primary/secondary Division of Rate 35 Customers*

In D.P.U. 20110-A **[*157]** the department determined that the company "must consider splitting the Rate 35 customers into voltage level categories." Re Western Massachusetts Electric Co. (1982) D.P.U. 20110-A. The company responded to the order in D.P.U. 20110-A by defining secondary and primary service level customers, identifying primary customers, allocating costs between primary and secondary, and designing primary and secondary service rates as alternatives to the current Rate 35 to recover the Rate 35 revenue requirement. The company explained that it had grouped customers by service level because it did not have the information necessary to identify customers by voltage level. Primary and secondary customers are distinguished primarily by whether the customer (primary) or WMECo (secondary) owns the transformer. The secondary customers, who do not own their own transformers, take power at lower voltage levels than do primary customers. However, as Dr. Overcast stated in his supplemental testimony, grouping customers by primary/secondary service levels results in attributing the same costs to the customer who is served by 13,800-volt lines in the street but who docs not own his own transformer as to the **[*158]** customer who has much lower voltage level lines in the street (and thus higher line losses).

The company does not, however, support the portion of the cost study which divides costs between primary and secondary or the division of Rate 35 at this time and has not sponsored the rates which appear in Exh WM-14 and were designed to collect the revenue requirements of the split class.

There is a substantial problem with the primary/secondary split that was raised only briefly by Dr. Overcast and that was not addressed by the industrial intervenors. By distinguishing between customers on the basis of transformer ownership and not on the basis of voltage level, the divided Rate 35 could, if done correctly, reflect the costs of transformer ownership, but it could not reflect differences in line losses between customers within the class. The department's order in D.P.U. 20110-A indicated our concern with the company's line loss study and with the inaccuracies created by the wide range of voltage levels on this rate. From the information submitted by the company in this case we still cannot determine the effect of variation in line losses and thus of costs within the primary and the secondary **[*159]** classes. The question asked in D.P.U. 20110-A, "whether the average [line loss] figure for a class varies so much from the loss figures for a member of the class that the allocation is clearly inequitable," is still unanswered.

We also find several problems with the allocation of casts between secondary and primary customers. The definition of "primary" versus "secondary" used to separate joint distribution costs such as poles appears arbitrary and has not been justified on this record. In addition, according to Bench Record Request 7, even primary customers served directly off substations may require poles, conduit, conductors, capacitors, and regulators, yet the allocator used by the company arbitrarily docs not assign any such costs to these customers.

The department finds that investigation of the proper treatment of Rates 35 should be continued. Rate schedules should group together customers with similar cost causation characteristics. We must still determine if costs differences among customers on the present Rate 35, resulting from differences in voltage levels and transformer ownership, arc substantial enough to warrant separate rate schedules. We direct the company to **[*160]** address this issue fully in its next rate filing.

The company's cost-of-service study is an improvement over that presented in D.P.U. 2GL10-A in several important respects. It is based on an improved line loss study and a definition of customer costs that was directed by the department. Further, by including fuel costs and revenues the study reflects the fact that customers with lower line losses are actually paying higher fuel costs per unit of power generated than high line loss customers. [24] However, we do not find that the split of costs between primary and secondary customers has been justified. Thus

[24] Unless this were compensated for by the lower line loss customers consuming a larger proportion of energy on peak than do high line loss customers.

we will accept the basic cost-of-service study for the purpose of revenue allocation, but will not use the determination of primary and secondary costs to divide Rate 35.

C. *Allocation of Revenue*

[40] The original testimony of Dr. Overcast stated that the company wanted to reduce disparities in rates of return while avoiding disruptive increases to individual customer classes. Therefore he limited the increase for any one class to 15 per cent of that class's total revenue; i.e., base rates plus fuel. The Rate 35 revenue requirement was increased by 15 per cent. The remainder of the revenue deficiency **[*161]** was allocated by an equal percentage increase of about 10 per cent. Within the small general class, however, Rate 23 (optional controlled water heating) was increased by 15 per cent, resulting in the other two rate schedules in this class [25] receiving increases of less than 10 per cent.

The industrial intervenors advocate allocating the increase half on the basis of Dr. Rosenberg's cost-of-service study and half on an equal percentage basis. Further, they argue this same approach should be applied to the subclasses within Rate 35.

We find the industrial intervenors' suggested method of allocating the increase unnecessarily conservative. Rates should reflect the cost of serving different classes of customers. Although the department applied half of the increase on the basis of the cost-of-service study method in D.P.U. 20110-A, we find the present study an improvement over the previous one and thus an adequate basis for a more substantial reallocation of revenue.

We find that the company's cost-of-service study can be relied on as a basis for revenue allocation. The company's method of first applying the increase to the customer class with the lowest rate of return, up to the **[*162]** maximum considered reasonable, and then applying the remainder of the increase to the other classes, is appropriate in this case. We concur with the company's view that considerations of rate stability require us, in this case, to limit rate increases to approximately 15 per cent. However, application of this standard requires us to consider not only the effect of revenue allocation but also the effect of changes in rate design. In the current case, that requires us to look at the combined effect of the rate increase and the redesign of Rate 35.

Since the effect of the change in rate design alone [26] has the effect of increasing the bills of large customers on Rate 35 by about 7 per cent, the company shall allocate the allowed revenue increase so that the total revenue requirement of Rate 35, including fuel revenues, increases by 8 per cent. [27] The remainder of the increase shall be spread among other customer classes (not rate schedules) so that the total revenue of each remaining class is increased by an equal per cent.

D. *Kate Design*

[41] The company has proposed rates which it maintains are based on the same principles as the rates approved in D.P.U. 20110-A. Current charges are increased **[*163]** by equal percentages within all rate schedules except for Rate 35. The proposed Rate 35 contains a customer charge, a demand charge for over 50 kilovolt-amperes, a fixed energy charge for up to 10,000 kilowatt-hours, an energy charge for over 10,000 kilowatt-hours but under 400 times the customer's maximum demand, and a lower energy charge for over 400 times the demand. The tail-block energy charge, when added to the fuel charge, is supposed to approximate the company's off-peak marginal energy costs. During the hearings Dr. Overcast concurred that current marginal energy costs were lower than when the original testimony had been filed, and he agreed to supply a Rate 35 which reflected more recent lower oil prices. In its brief, the company indicates that it would be desirable to update marginal energy charges further in its compliance filing.

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[25] Rale 24 (church) and Rale 20 (small general).

[26] Sections D and E, *infra*.

[27] Refer to Exh WM-13, Schedule E-4.2.

According to the industrial intervenors, the proposed design for Rate 35 would result in increases to primary and particularly to large primary customers which are not justified by the company's or the intervenors' cost-of-service study. Industrial intervenors argue that (1) proposed increases would be in excess of cost-based increases; (2) **[*164]** proposed increases to large primary customers would exceed the company's own guidelines; and (3) the company's marginal energy calculations are in error. [28]

The industrial intervenors argue that not only the proposed rates are not cost based for primary customers, but also that they result in increases to this subclass that exceed the company's own guideline of a 15 per cent maximum increase to total bills. Mr. Drazen's testimony indicated that large primary customers would receive increases of 21.3 per cent. Moreover, the intervenors argue, it would be more appropriate to compare rate increases to base revenues, since the fuel clause in Massachusetts is fully compensatory.

The department has fairly consistently considered the impact of rate increases on customers' total bills rather than on only the base rate portion. We find that it is not inappropriate that large Rate 35 customers receive larger percentage increases than small Rate 35 customers, since several years of equal percentage surcharges have increased larger customers' total bills by less than average. We do agree with the intervenors' position that it is inconsistent of the company to maintain that bills should not **[*165]** be increased by more than 15 per cent and then to design rates which result in substantially larger increases to a subclass of customers and will modify revenue allocation accordingly.

The industrial intervenors also argue that the company's calculations of marginal energy cost are in error. First, they argue that oil is the marginal fuel at all hours only because Northfield Mountain is being-pumped during off-peak hours. In support of this assertion they note that Northeast Utilities' total low energy cost megawatt capacity of hydro, nuclear, and coal is well above its minimum load and is above its load for 4,000 hours per year. Second, they state that a proper determination of off-peak marginal costs would take out the effect of the Northfield load, since Northfield is being pumped off peak to meet on-peak load. Off-peak marginal costs would be lower without pumping. Third, they argue that even if oil were the incremental off-peak fuel, the proposed rates are still too high. In D.P.U. 20110-A the company proposed energy charges of 24 mills on peak and 18 mills off peak, yet with lower current oil prices the company has proposed energy charges of 30.17 mills and 18.8 mills (the **[*166]** latter charges were contained in Bench RR-7).

Based on this record, we find that even if Northfield Mountain pumping were not included, oil is used in many off-peak hours, and thus is the off-peak marginal fuel. Therefore, we find reasonable the principles on which the proposed redesign of Rate 35 is based, although the proposed energy charges must be reduced to reflect current lower oil costs.

E. *Specifics of Rate Modifications*

[42] The company's rate structure was modified at its request in D.P.U. 20110-A to reduce declining block rates. Increasing all existing charges (in rates other than Rate 35) by an equal percentage as it now proposes will increase the differential between the remaining block rates, and the company has not justified this change. Therefore, for every rate schedule except for Rate 35, we order the company to increase existing customer charges by the percentage increase in class base revenue allowed in this proceeding, and to increase the energy charges by equal cents per kilowatt-hour within each rate schedule.

As we have indicated above, we find that the price for the last units of energy consumed should equal the marginal energy cost. However, the company's proposed Rate 35 **[*167]** must be modified to reflect lower marginal energy costs. We therefore direct the company to file a Rate 35 which modifies the rate submitted in Bench Record Request 6 in the following manner: The energy charge for over 400 times the demand shall remain the same, but all other charges shall be reduced by an equal percentage. We have determined that the new rate, including the effect of allocating the revenue deficiency found in this order, will not increase large customers' bills by more than the

[28] The industrial intervenors also make numerous objections to the rate for primary customers; however, we will not address these since we have rejected the primary/secondary division of Rate 35.

company guideline of a 15 per cent increase to total bills. We also note that the rate will be less disruptive to former Rate 21 customers than is the current rate.

Both the existing and the proposed Rate 35 contain provisions which (1) credit customers who take service at distribution voltage (because the customer owns its own transformer) and (2) both provides lower charges and reduces the metered kilowatt-hours by 5 per cent before billing for customers receiving power at transmission voltage. While it is appropriate to reflect lower line losses and the fact that the company needs less equipment to serve customers at these levels, there was testimony during the proceeding that the credits **[*168]** are well above a level that would be cost based. This is particularly true of the single transmission service customer, as is evident in the low rate of return earned by this subclass. Since the rate design described above will increase the bills of some of the customers who receive the distribution voltage credit by approximately 15 per cent, we will not require a reduction of the distribution voltage credit. Therefore the company shall modify the proposed rates for the transmission service provision so that this customer receives an increase of 15 per cent over total current revenue.

IX. *Customer Service*

FCAC has requested that the company be ordered to discontinue issuing termination notices to customer households where all residents are sixty-five years of age or older. *General Laws Chap 164, § 124E* provides that households where all members are sixty-five years of age or older are eligible for special protection from termination. Under authority granted by § 124E, the department promulgated regulations requiring that where a utility seeks department permission to terminate an elderly account, special notice to the elderly customer including an opportunity for hearing at the department before termination must be provided **[*169]** to the customer and to the department of elder affairs. *220 CMR 25.05*.

FCAC argues that cross-examination of company witness Locke indicated although WMECo had complied with the letter of the regulation protecting elderly customers from actual termination, the company continued to send such customers the standard collection notices threatening termination.

The department is particularly concerned with the plight facing the elderly poor served by utilities under its jurisdiction. The elderly poor who receive these shutoff notices are subject to inordinate mental stress even though their service cannot legally be terminated. Through fear of termination, they may use money needed for food to pay utility bills and thereby lose their right to assistance from several public programs which require unpaid bills before assistance can be provided.

Out of that concern, the department has promulgated an emergency regulation amending its existing billing and termination procedures. Effective April 19, 1983, the amendment requires the elimination of termination notices to all households which have notified a utility company that all residents of that household are sixty-five years of age or older until **[*170]** the company has requested and received permission to terminate the service from the department of public utilities. The regulation also requires that notice of the request for permission to terminate and of the customer's right to a hearing before the department regarding the requested termination be furnished to all affected customers. *220 CMR. 25.05(3)*.

In view of the amendment to the termination procedures, the department finds it unnecessary to issue the ruling requested by FCAC. However, the parties in this proceeding may wish to comment on this emergency regulation at the public hearing scheduled for that purpose on June 9, 1983.

MA Department of Public Utilities Decisions

End of Document

1981 Tex. PUC LEXIS 335; 6 Texas P.U.C. Bulletin 697

Public Utility Commission of Texas

April 23, 1981

DOCKET NO. 3546

TX Public Utilities Commission ***Decisions***

Reporter
1981 Tex. PUC LEXIS 335 *; 6 Texas P.U.C. Bulletin 697 **

APPLICATION OF GULF WATER BENEFACTION COMPANY FOR AUTHORITY TO IMPOSE A SURCHARGE WITHIN HARRIS COUNTY

Disposition: Examiner's Report adopted. Application dismissed without prejudice based on failure to comply with P.U.C.PROC.R. 052.01.00.039(a)(2).

Core Terms

gulf, has, was, audit, staff, surcharge, proposed rate, customer, sewer, supplemental pleading, financial statement, test period, benefaction

Headnotes

[*1]

WATER/SEWER

PROCEDURE - PLEADINGS

Dismissal of application pursuant to P.U.C.PROC.R. 052.01.00.051(a)(1) and (a)(5) is appropriate when applicant incorporates by reference and relies upon schedules found by the Commission in a previous docket to be deficient and when official notice is taken of the entire record in the prior docket including the Commission's findings concerning the schedules.

Panel: George M. Cowden, Garrett Morris, H. M. Rollins; Commissioners

Opinion By: Carolyn Shellman, Hearings Examiner

Opinion

[697]** EXAMINER'S REPORT

Procedural History

On November 7, 1980, Gulf Water Benefaction Company filed an application to increase its revenues by $315,000 by imposing a surcharge on its sewer utility customers within Harris County. Proposed to be effective on December 12, 1980, the request constitutes a major change in rates as defined by Section 43(b) of the Public Utility Regulatory Act, *TEX.REV.CIV.STAT.ANN. art 1446c* (Supp. 1979) (the Act). On December 1, 1980, the General Counsel of the Commission filed a motion to dismiss the application citing as the basis therefor, various deficiencies in the application's supporting schedules and documents. By order dated December 1, 1980, **[*2]** the Examiner notified Gulf of the specific deficiencies in its application and, pursuant to P.U.C. PROC. R. 052.01.00.035(b), gave Gulf ten days from receipt of the order in which to correct them, failing which the effective date of the proposed rate increase was to be tolled in accordance with the above-cited rule. The Examiner also suspended the implementation of the proposed rate for 120 days beyond December 12, 1980, in accordance with Section 43(d) of the Act pending a determination as to whether the effective date should be tolled.

On December 16, 1980, Gulf filed supplemental pleadings in response to the Examiner's December 1, 1980, order. Then, on February 19, 1981, the General Counsel of the Commission filed a Renewed Motion to Dismiss alleging that the supplemental pleadings failed to correct the deficiencies in Gulf's application. In order to provide Gulf an adequate opportunity to respond to the motion and to defend the adequacy of its application, a prehearing conference was held on Friday, March 6, 1981, at the Commission offices. Appearing at the conference were Mr. Robert Pine for Gulf and Mr. Fernando Rodriguez for the Commission Staff. Official notice was taken **[*3]** of Docket No. 3487, Application of Gulf Water Benefaction Company for Authority to Increase Rates within Harris County, 6 P.U.C BULL. (Jan. 8, 1981) and evidence was received and arguments made concerning the motion to dismiss. This report has been prepared in accordance with P.U.C. PROC. R. 052.01.00.035 to present to the Commission for consideration the Examiner's conclusion that Gulf's pleadings are deficient, and the attendant recommendation that this docket should therefore be dismissed.

[698]** Discussion

Gulf's initial filing in this docket consisted of a three page document evidently intended as the statement of intent required by Section 43(a) of the Act, three pages of prepared testimony of one witness plus three one-page exhibits attached thereto, and a one page document labeled Schedule P. In place of Schedules A-M and R of the Commission-prescribed rate filing package (submission of which package is mandated by P.U.C. PROC. R. 052.01.00.039(a)(2)), Gulf's application stated that the Company did not rely on the information contained in those schedules in support of its surcharge request but that for informational purposes, Schedules A-M and R filed in Docket **[*4]** No. 3487 (cited above) should be incorporated by reference in this docket. Gulf's supplemental pleadings filed on December 16, 1980, consisted of a narrative statement (not in the form of testimony) providing some additional background on the surcharge proposal but failed to supplement the initial evidentiary submissions in support of the alleged revenue deficiency. (The surcharge Gulf proposed is a $12.00 per month per customer fee over and above the tariffed sewer rate. With the money generated by this surcharge Gulf plans to finance capital improvements to the sewer system assets it operates, assets owned by People's National Utility Company. While the supplemental pleadings indicate that the exact cost of the capital improvements cannot be ascertained until the work is completed, Gulf proposes to obtain a bid from a contractor who will pay for the improvements himself, then be repaid by Gulf from a "sinking fund" which would recover double the capital outlay over a five year period at a 31.5 percent implied compound annual interest rate.)

The Commission Staff had a variety of objections to the Gulf proposal and the supporting application, all of which were specified for the **[*5]** Company so that the alleged defects could be cured. The Staff's primary objection was that, even as supplemented, the application does not conform to the Commission's rate filing package for Class A & B Water and/or Sewer Utilities and, hence, should not be considered. Further, the Staff argued that rates follow service, that it is this Commission's policy to design rates to provide a return on the utility's investment only after the investment is made, not to require customers to pay for the entire investment beforehand. Finally, the Staff contended that the incorporated Schedules A-M and R have already been found by the Commission in Docket No. 3487 to be fatally defective, and that the remaining application is wholly insufficient to support Gulf's claimed need for additional revenues.

Gulf's response to these arguments was that the Company is bankrupt, that it cannot borrow money, that the only way it can finance necessary system improvements is to require customers to provide needed dollars through rates, and finally, that the requested surcharge is not a novel ratemaking proposal, that the Commission is obliged (emphasis added) to consider Gulf's application, and **[*6]** that failure to do so is an "abdication of regulatory responsibility" (Supplemental Pleadings, at 9).

In the Examiner's opinion there are a number of problems with Gulf's rate application, not the least of which is the appropriateness of designing sewer rates to provide money in advance for improvements in assets owned by another utility. However, some of these issues pertain solely to the merits of the application. The threshold question in this docket appears, therefore, to be whether Gulf has complied with Rule -039 in filing its application. As will be detailed below, the Examiner's conclusion is that Gulf's filings do not comply with Rule -039(a)(2), that they are wholly inadequate to support the major rate charge requested, and that this lack of compliance with filing requirements means that **[**699]** the Commission's jurisdiction has not been adequately invoked, rendering the application subject to dismissal pursuant to P.U.C. PROC. R. 052.01.00.051(a)(5).

Rule -039(a)(2) requires the filing of all evidence and testimony in support of a rate application on the day the application is filed. To be included are annual financial statements (examined and reported on by an independent **[*7]** certified public accountant) , dated within the test year, and the accountant's report on a test year review. A specific definition for what constitutes a test year is provided in P.U.C. PROC. R. 052.01.00.012(35). The purpose of these requirements is at least twofold. First, in accordance with generally-accepted regulatory principles and the specific practice of this Commission, the Staff determines a utility's need for a revenue increase by identifying the reasonable expenses it incurred during a recent test period, adjusting those expense requirements for known and measureable changes, and calculating the utility's resulting revenue deficiency based on the revenues it earned during the same test period. Without the test period data just described, no evidentiary support exists to show that the utility's current revenues are not sufficient to pay for all necessary and reasonable operating expenditures, in this case, the system improvements. Without Schedules A-M and R, Gulf's application is merely an assertion that the Company has no money, needs to spend $315,000, and wants the Commission to require each of its 774 customers to pay $12.00 per month more than they are now paying **[*8]** for an indefinite period in order to pay for system improvements whose cost is as yet unspecified and for which no contract has been signed.

The second purpose of the Commission's filing requirements in this case is to prevent the Staff from being required to audit the Company's books to confirm that reported expenses were actually incurred before reviewing their reasonableness. Requiring the Staff to make this kind of audit because Gulf does not file the required schedules would shift to the Staff the burden of proof which Section 46(b) of the Act places upon the applicant.

The Examiner believes that these two reasons adequately explain and justify the need for compliance with Rule -039. There is consequently no merit in Gulf's contention that it need not file or rely on Schedules A-M and R in order to support its proposed rate change. These schedules are critical to the Staff's consideration of the case and in their absence Gulf's application would be fatally defective and subject to dismissal.

The fact that Gulf incorporated by reference in this docket Schedules A-M and R of Docket No. 3487, however, does not in this case cure the deficiencies in the application. As was **[*9]** alleged by the General Counsel, the application in Docket No. 3487 and the schedules contained there in were found by the Commission to be deficient. (See Examiner's Report and Final Order, Docket No. 3487.) Official notice having been taken herein of the entire record in Docket No. 3487, the Examiner does not feel it necessary to repeat entirely all the Commission's findings concerning the schedules in question. In summary, however, the Commission found that Gulf's financial statements and auditor's report were so unreliable that their mere filing did not constitute compliance with Rule 39 and that, as a result, Gulf's application was incomplete. Based on these conclusions, the Commission dismissed Docket No. 3487 for want of jurisdiction and for failure to prosecute under Rules -051(a)(5) and (1).

Schedules A-M and R incorporated by Gulf in this application are identical to those filed, reviewed, and found deficient in Docket No. 3487. Gulf was a party to Docket No. 3487 and has acquiesced to the taking of official notice herein of the entire record in that **[**700]** docket. Moreover, the specific deficiencies in the schedules and in the application as a whole have been [*10] brought to Gulf's attention in this docket and Gulf has been given an opportunity to correct them but has failed to do so. For these reasons, the Examiner believes that Gulf's application in this docket is deficient in that it fails to comply with Rule -039, that by failing to file the necessary documentation in support of its application, Gulf has failed to pursue its rate request and has failed to properly invoke the Commission's jurisdiction. Dismissal of this docket should therefore be ordered pursuant to P.U.C. PROC. R. 052.01.00.051(a)(1) and (a)(5).

As one final justification for this recommendation, the Examiner believes attention should be drawn to a compelling policy reason supporting dismissal. In this docket Gulf has requested a major rate increase, a request that, because of its size and the language of the Act and Commission Rules, is accorded special attention and review, and is subject to particular filing requirements. Yet, in making this request, Gulf has provided almost no supporting data, expecting the Commission to rely on its unsubstantiated assertion that it needs the money and that it intends to make substantial system improvements for which no contracts [*11] have yet been signed. Moreover, Gulf does not own the assets to be improved, a fact which does not automatically bar relief but which marks this cases as a particularly unusual one. In view of these peculiarities, it appears all the more important for Gulf to shoulder the burden of supporting its application with specific, credible evidence. Furthermore, it is illogical and a complete misreading of the Act for Gulf to assert as Mr. Pine did at the March 6 conference that this Commission must "figure out some way to get this company the money it needs to make necessary improvements" when the Company cannot or will not demonstrate what its past and current revenues have been, what its expenses are, where past revenues have gone, and why no system improvements have been made up to now.

The Examiner recommends that this docket be dismissed and that the Commission adopt the following Findings of Fact, Conclusions of Law, and proposed Order.

Findings of Fact

1. On November 7, 1980, Gulf Water Benefaction Company filed an application to increase its revenues by $315,000 by imposing a surcharge on its sewer utility customers within Harris County.

2. The General Counsel has moved [*12] to dismiss Gulf's application because of alleged deficiencies in the rate filing.

3.By order of the Examiner dated December 1, 1980, Gulf was notified of specific deficiencies in its application and the proposed rate increase was suspended for 120 days beyond the December 12, 1980, effective date.

4. A prehearing conference was held on March 6, 1981, to give Gulf the opportunity to defend the adequacy of its application in response to the General Counsel's motion to dismiss.

5. In Docket No. 3487, <u>Application of Gulf Water Benefaction Company for Authority to Increase Rates within Harris County,</u> 6 P.U.C. BULL. (Jan. 8, 1981) the Commission dismissed Gulf's application for want of jurisdiction and failure to prosecute pursuant to P.U.C PROC. R. [**701] 052.01.00.051(a)(1) and (a)(5) based on a finding that Gulf had not complied with P.U.C. PROC. R. 052.01.00.039 in that its filed schedules were not credible.

6. The schedules found to be insufficient in Docket No. 3487 have been incorporated herein by reference and constitute the major body of evidence in support of Gulf's application herein.

7. On December 16, 1980, Gulf filed supplemental pleadings in response to [*13] the Examiner's order citing deficiencies in the application but Gulf was notified by the General Counsel's Renewed Motion to Dismiss filed on February 19, 1981, that serious deficiencies still existed.

8. By agreement of all parties, official notice was taken in this docket of the entire record in Docket No. 3487.

9. The evidence and testimony presented by the Staff and Gulf, the Examiner's Report, and the Commission's Order in Docket No. 3487 indicate that Gulf's accountant failed to adhere to generally accepted accounting and auditing standards when preparing the certificate required by P.U.C. PROC. R. 052.01.00.039(a)(2) by failing to

reconcile annual financial statements and correct obvious errors in them, by ignoring or inaccurately reflecting major liabilities of the Company, by issuing an unqualified opinion on an apparently bankrupt company, by failing to obtain supporting or corroborating documents in support of his examination of Company records and financial statements, and by auditing books and financial statements he prepared.

10. The certification and audit prepared by Gulf's accountant as contained in Gulf's Schedules A-M and R cannot be relied on to be an objective **[*14]** opinion on Gulf's financial position and test period expenses because of the accountant's demonstrated failure to conform to generally-accepted accounting and auditing standards (as set out in Finding of Fact No. 9) and because his testimony indicates that he relied substantially on undocumented representations made to him by Company representatives, his own familiarity with the Company, and the records he prepared for the Company without obtaining impartial or demonstrable corroboration for any of these.

Conclusions of Law

1. The Commission has no jurisdiction over this matter because Gulf has failed to comply with the initial filing requirements of P.U.C. PROC. R. 052.01.00.039(a)(2), having submitted an incomplete application for the Commission to consider. The application is therefore subject to dismissal for lack of jurisdiction pursuant to P.U.C. PROC. R. 052.01.00.051(a)(5).

2. Pursuant to Section 43(a) of the Public Utility Regulatory Act, *TEX.REV.CIV.STAT.ANN. art. 1446c* (Supp. 1979), the first day Gulf's proposed rate increase could have been effective was December 12, 1980.

[702]** 3. Gulf's proposed revenue increase constitutes a "major change" as defined by **[*15]** Section 43(b) of the Act.

4. P.U.C. PROC. R. 052.01.00.039 requires Gulf to file with its rate application in this docket financial statements dated within its June 30, 1980, test period and a certificate from a certified public accountant that the statements were examined and a test year review conducted.

5. Inherent in the above-described requirement of Rule 39 is the assumption that an audit shall have been performed according to generally-accepted accounting standards by an independent accountant reporting on a test year review of the Company's records.

6. By failing to file the necessary documents required by P.U.C. PROC. R. 052.01.00.039 as part of its application for a major change in rates, Gulf has failed to prosecute its case, thus making it subject to dismissal pursuant to P.U.C. PROC. R. 052.01.00.051(a)(1).

7. Gulf has not complied with P.U.C. PROC. R. 052.01.00.039 because the audit report filed in Docket No. 3487 and incorporated by reference herein cannot be relied upon to indicate that an audit was actually performed or that Gulf's financial statements accurately reflect the Company's financial position.

8. To require the Staff to audit Gulf's books in order **[*16]** to confirm the accuracy of the rate application is inconsistent with Section 40(b) of the Act, which places the burden of proof as to the reasonableness of proposed rates on the applicant utility.

9. The Commission should dismiss Gulf's application in this docket pursuant to P.U.C. PROC. R. 052.01.00.051(a)(1) and (5).

CAROLYN SHELLMAN

HEARINGS EXAMINER

ORDER

In public meeting at its offices in Austin, Texas, the Public Utility Commission of Texas finds that the above-referenced application was processed in accordance with applicable statutes by an Examiner who prepared and filed a report containing Findings of Fact and Conclusions of Law, which Examiner's Report is adopted and made a part hereof. The Commission further issues the following Order:

The application of Gulf Water Benefaction Company in this docket is hereby dismissed without prejudice.

GEORGE M. COWDEN

GARRETT MORRIS

H. M. ROLLINS

COMMISSIONERS

TX Public Utilities Commission Decisions

End of Document

2007 Fla. PUC LEXIS 84

Florida Public Service Commission

February 14, 2007, Issued

DOCKET NO. 060262-WS; ORDER NO. PSC-07-0129-SC-WS, 07 FPSC 2:116

FL Public Service Commission Decisions

Reporter
2007 Fla. PUC LEXIS 84 *

In re: Application for increase in water and wastewater rates in Pasco County by Labrador Utilities, Inc.

Core Terms

meter, labrador, was, wastewater, staff, replace, customer, interim, has, kgal, months, refund, plant, rate increase, fine, annual report, rate case, gallons, show cause proceeding, burden of proof, show cause, consume, flaw, apparent failure, test result, satisfactory, unaccounted, pump, consummate, gallonage

Panel: The following Commissioners participated in the disposition of this matter: LISA POLAK EDGAR, Chairman; MATTHEW M. CARTER II; KATRINA J. TEW

Opinion

ORDER INITIATING SHOW CAUSE PROCEEDINGS AND NOTICE OF PROPOSED AGENCY ACTION ORDER DENYING RATE INCREASE AND REQUIRING REFUNDS

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that, except for the initiation of show cause proceedings, the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule *25-22.029, Florida Administrative Code*.

I. Background

Utilities, Inc. (UI or parent) is an Illinois corporation which owns approximately 80 utility subsidiaries throughout 16 states including 16 water and wastewater utilities within the State of Florida. Currently UI has ten separate rate case dockets pending before this Commission. These dockets are as follows:

Docket No. UI	Subsidiary
060253-WS	Utilities Inc. of Florida
060254-SU	Mid-County Services, Inc.
060255-SU	Tierra Verde Utilities, Inc.
060256-SU	Alafaya Utilities, Inc.

Docket No. UI	Subsidiary
060257-WS	Cypress Lakes Utilities, Inc.
060258-WS	Sanlando Utilities, Inc.
060260-WS	Lake Placid Utilities, Inc.
060261-WS	Utilities Inc. of Pennbrooke
060262-WS	Labrador Utilities, Inc.
060285-SU	Utilities Inc. of Sandalhaven

[*2]

This Order addresses Docket No. 060262-WS.

Labrador Utilities, Inc. (Labrador or utility) is a Class B water and wastewater utility located approximately one mile east of Zephyrhills, in Pasco County. The utility is located within the Southwest Florida Water Management District (SWFWMD), but the utility's service territory is not in a water use caution area. The utility serves approximately 902 water and 896 wastewater customers. According to its 2005 annual report, Labrador reported revenues of $ 9 $ 3, 184 and $ 327,716 for water and wastewater, respectively. Labrador reported a net operating loss of $ 12,568 for water and a net operating income of $ 42,856 for wastewater.

On May 15, 2006, the utility filed its application for approval of a final and interim rate increase in this docket and requested that the Commission process the case under the Proposed Agency Action (PAA) procedure. After review of the Minimum Filing Requirements (MFRs), our staff determined that the MFRs contained a number of deficiencies that required revisions by the utility. Those revisions were filed, and the official filing date for the utility's final rate increase was established as August 22, 2006. **[*3]**

The utility's requested test year for interim and final purposes is the historical test year ended December 31, 2005. Labrador requested annual interim revenue increases of $ 55,637, or 36.95%, for water, and $ 97,826, or 28.55%, for wastewater. On July 19, 2006, this Commission approved interim revenue increases of $ 45,319, or 30.06%, for water, and $ 51,294, or 14.91%, for wastewater. The utility has requested final revenue increases of $ 103,047, or 68.43%, for water and $ 145,461, or 42.45%, for wastewater.

On November 2, 2006, our staff held a customer meeting in Zephyrhills, Florida. Approximately 435 customers attended this meeting and several took the opportunity to express their opinions and concerns regarding Labrador's rates and service. The customers presented our staff with a petition signed by approximately 750 customers opposing the rate increase. Our staff also responded to 75 letters and 37 emails from customers complaining about Labrador's quality of service, quality of the water, and odors from the wastewater plant.

Water and wastewater rates were last established for this utility in its 2003 rate proceeding. [1] In that rate case, Labrador requested revenue requirements **[*4]** of $ 199,958 and $ 389,475 for water and wastewater, respectively. The requested revenue requirement exceeded test year revenues by $ 144,477, or 260.41% for water, and $ 260,380, or 201.70%, for wastewater. We approved revenue requirements of $ 157,075, or 183.12% for water, and $ 324,000, or 150.98% for wastewater, and the increased rates went into effect on February 3, 2005.

On November 13, 2006, our staff conducted a conference call with Labrador to discuss concerns with data supplied by the utility. The two major concerns were: 1) the reliability of the test year consumption data, and 2) the amount of wastewater treated at the treatment plant. By letter dated November 22, 2006, the utility supplied additional information. **[*5]** Although this additional information was supplied, our staff states that it is still unable to rely on this data to set rates.

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[1] See Order No. PSC-04-1281-PAA-WS, issued December 28, 2004, in Docket No. 030443-WS, In re: Application for rate increase in Pasco County by Labrador Utilities. Inc. Consummating Order No. PSC-05-0087-CO-WS, issued January 24, 2005, made Order No. PSC-04-1281-PAA-WS final and effective.

This Order addresses the denial of a final revenue increase, the refund of interim rates, and initiation of Show Cause proceedings for the apparent failure of the utility to comply with a Commission order. We have jurisdiction pursuant to Section 367.081 and *367.161, Florida Statutes* (F.S.).

II. Denial of Rate Increase

Our analysis of whether the utility has demonstrated a need for a rate increase focuses on two major areas: engineering data and billing determinants.

A. Engineering Data

Our staff reviewed the utility's MFR "F" Schedules, which lay out the engineering information required to process rate cases. The water and wastewater monthly flow data appeared to be highly questionable. The F-1 Schedule, Gallons of Water Pumped, Sold and Unaccounted for Water, show Labrador sold more water than it pumped in April, May, and June 2005. In addition, a review of the F-2 Schedule, which contains wastewater treatment plant flow data, revealed Labrador treated more wastewater **[*6]** than water sold to customers in ten out of the twelve months of the test year. Moreover, its F-9 and F-10 Schedules (the single family residential (SFR)) data (Columns 2 & 3) and the flow data (Column 7)) do not match the data in the utility's Annual Reports for the years (2003-2005). Therefore, this data appears to be erroneous.

In a data request, dated October 2, 2006, our staff requested an explanation regarding the questionable water and wastewater flows data. In addition, our staff requested the F-9 and F-10 Schedules be reconciled with the utility's annual reports.

On October 30, 2006, in response to that data request, the utility stated "it has been difficult to determine the reason for this difference, since there is such a short history of metered customer consumption. " In addition, the utility stated it had complied with Order No. PSC-04-1281-PAA-WS, in which this Commission required the utility to test all of its customers' water meters by June 30, 2005. Further, Labrador stated in its response that it tested all customer meters and replaced over 300 (approximately 37%) of its meters. However, in its report to staff, the utility showed that it did not test all of the meters, **[*7]** and that some meters were tested or replaced as late as May of 2006. Therefore, Labrador appears to be in direct violation of the mandate of the order. This apparent violation will be addressed below.

The utility indicated that some meters were found to be registering above 100% while others were not functioning at all. The utility stated the inaccuracies of the meters may be a factor in the difference between gallons pumped and sold. In addition, the utility indicated that in May 2006, the RV park's meter was replaced because it was also reading low. The utility stated the RV Park's meter was reading 10.5% low or 220,000 gallons annually. This was determined by comparing the same period meter readings in 2005 and 2006. The utility further stated that it had not yet been able to find a satisfactory explanation for the erratic and high unaccounted for water.

In response to our staffs question concerning the treated wastewater gallons exceeding the water sold, the utility stated the wastewater flow meter had been installed in the wrong location and was double counting the filter backwash. In addition, the meter was miscalibrated and was reading high; however, Labrador stated it did **[*8]** "not know the magnitude of the error." The utility further indicated the meter was replaced at the time it was relocated; therefore, it believed that a more accurate picture of wastewater flows would be presented if seasonal month flows after the flow meter replacement were used instead of the test year flows before the meter replacement. This flow data would be more than six months after the test year. Labrador indicated it would continue to monitor the wastewater plant, the plant flow meters, and customer meter readings until there is a satisfactory resolution.

In regards to reconciling the F-9 and F-10 Schedules with the Annual Report, Labrador stated: "In preparing the MFRs, no attempt is made to reconcile the total sales to those reported in the annual reports. It serves no useful purpose." Pursuant to Rule 25-30.110(2), Florida Administrative Code (F.A.C.), the utility is required to reconcile its MFRs with its annual reports.

On November 7, 2006, during a telephone conference with the utility, the Office of Public Counsel, and our staff, the utility stated it did not know the level of meter error. However, it suggested that our staff **[*9]** use the January and February 2006 wastewater flow data as a comparison with the wastewater flow data during the same period of 2005. Our staff did not agree with using the test-year data, which was known to be erroneous, with the out-of-test-year data.

The utility submitted a follow-up letter dated November 21, 2006, concerning the issues addressed during the November 7, 2006, telephone conference. The letter contained new information regarding the water meter readings for 2006. The utility stated that since it serves a mobile home community that experienced no material growth between 2005 and 2006, the 2006 water consumption data was analyzed to verify the accuracy of the 2005 water consumption. The utility concluded the difference is less than one percent (1%). In addition, the utility stated there was no legitimate basis to question the 2005 consumption data.

Labrador also provided new information regarding the wastewater flow data. With the relocation and recalibration of the wastewater flow meter, the utility indicated that since June 2006, the wastewater flows have been averaging 74 percent of the water pumped and approximately 83 percent of the water sold, which is consistent **[*10]** in a residential community with the amount of water reasonably expected to be returned to the wastewater system.

The utility's MFRs' water flow data showed that it sold more water than it pumped, and had several months of high unaccounted for water. The MFRs' wastewater flow data showed that it treated more wastewater gallons than water sold. Also, as stated above, the RV park's water meter was inaccurate and replaced in May 2006. As stated earlier, Labrador indicated it could not find a satisfactory explanation, but would continue monitoring the plant, plant meters, customer meter readings, and inspect the system until there is a satisfactory resolution. Later, after our staff informed Labrador that it was considering recommending dismissal of this case, the utility provided new data that showed a difference of less than one percent (1%) between the flows for 2005 and 2006. Our staff believes this data is also erroneous and cannot be used to calculate used and useful (U&U) percentages. We agree. Further, we do not believe the submitted data is reliable since a large percentage of the water meters' flow measurements are inaccurate, as stated by the utility in its report and its response **[*11]** to staffs data requests.

In addition, the MFR's wastewater flow data indicated that on ten occasions, the utility treated more wastewater than water sold to customers. In fact, the data showed that on three occasions the amount of wastewater treated was double the amount of water sold. Also, during November 2005, the amount of wastewater treated was almost triple. As indicated above, initially the utility stated it was aware the wastewater plant's meter was miscalibrated and was located in the wrong place in the system. In addition, the utility stated the meter was reading high. Further, Labrador stated it did not know the magnitude of the error; however, it would continue monitoring the plant, plant meters, customer meter readings, and inspect the system. Later, after our staff informed Labrador that it may be recommending dismissal of this case, the utility provided new data containing water sold for the months January through November, 2006. Labrador believed this analysis would be adequate, with the proper adjustments made to the test year data, to complete its filings and continue forward with this case. Our staff did not find the new information to be compelling, and as discussed **[*12]** in this section and in the Billing Determinants section below, we agree.

The data contained in the utility's MFRs, monthly DEP reports, and the Annual Report do not match. Therefore, we find the accuracy of the data to be questionable.

Based on the above analysis, we find that the inconsistencies of the data found in the utility's MFRs, Annual Reports, and DEP monthly reports make all the data unusable. Because the utility has not provided accurate water or wastewater data, and the conflicting data cannot be reconciled, the appropriate used and useful percentages cannot be determined. In addition, the utility stated the flow data was incorrect and admitted that it did not know the magnitude of the error. We have made adjustments to flow data in past rate cases for utilities when the corrections were based on known and measurable changes. However, the data supplied by Labrador has so little probative value that we cannot make corrective adjustments in this case, and we cannot use the utility's data to calculate

U&U percentages, determine the percentage of Inflow and Infiltration, or the level of unaccounted for water in this case.

B. Billing Determinants

1. Test Year Water Thousand **[*13]** Gallons (Kgal) Sold

During the pendency of the last rate case, the utility performed meter accuracy tests on 47 meters, of which only 41 were found to be accurate. This correlated to a 13 percent error rate for the sample. In response to the meter tests, we found that "this error rate could be indicative of a system-wide problem." [2] Consequently, we ordered Labrador to test all of its meters by June 30, 2005, and make any necessary repairs or adjustments. [3] By letter dated July 15, 2005, the utility informed staff that testing remained incomplete because approximately 150 customers had turned off their isolation valves while away for the summer. The utility stated that it expected to complete testing by early November 2005, when these homeowners returned.

The utility filed a final meter testing report on June 23, 2006. In a letter that accompanied the final report, the utility notified our staff that the report reflected test results completed as of May 24, 2006. **[*14]** On November 7, 2006, Labrador submitted a corrected, final report of the meter flow test results as required by this Commission. [4] The test results are summarized in Table 1 below.

TABLE 1

FINAL REPORT -- METER TEST FLOW RESULTS: METERS REPLACED

Meter Test Results	2005 Qtr 1	2005 Qtr 2	2005 Qtr 3	2005 Qtr 4	Total 2005	2006	Total Meters Replaced
Meters Read Slow -- Replaced	7	4	4	3	18	1	19
Meters Read Fast -- Replaced	34	54	23	12	123	2	125
Meters Replaced But Not Tested	1	0	9	0	10	57	67
Meters Replaced But Tested Within PSC Accuracy Reqmts	3	7	22	35	67	34	101
6" Meter at RV Park Read Low -- Replaced	0	0	0	0	0	1	1
TOTAL REPLACED	45	65	58	50	218	95	313

As shown in Table 1, in 2005, the utility determined through meter tests that 141 meters (or 16 percent of the utility's 900 total meters) were defective due to slow or fast readings. The 16 percent defective rate is three percentage **[*15]** points greater than the 13 percent defective rate from the sample tests taken in the last rate case. The utility replaced 218 meters (77 more than were found to be defective) during the 2005 test year. To further complicate matters, in response to staffs fifth data request, dated October 2, 2006, question number 2, the utility advised our staff that the 6" meter serving the RV park was tested and replaced in mid-2006 because it

[2] Order No. PSC-04-1281-PAA-WS, p. 4.

[3] Id.

[4] See Order No. PSC-04-1281-PAA-WS.

was reading slow. In the aforementioned data request, the utility was asked to explain: a) how it could have sold more water than it pumped during the test year months of April through June; and b) why there were months with unaccounted for water percentages greater than 10 percent. In the utility's response, filed on October 30, 2006, it stated:

> It has been difficult to determine the reason for this difference....The utility tested all customer meters and replaced about 37% of them found to be inaccurate....In May, 2006...the park meter was replaced. It was reading low....The utility has not yet found evidence of significant leaks in the system and has not yet been able to find a satisfactory explanation for the erratic and high unaccounted for water…

[*16]

This Commission expressed concern during the utility's last case that defective meters could be a system-wide problem. The 16 percent defective rate of the utility's meters during the test year, coupled with the discovered inaccuracy of the utility's 6" meter, substantiates that concern. This creates several problems with the resulting test year kgal sold data that cannot be overcome. Not only is it impossible to know how long each meter operated defectively during the test year, it is impossible to know the magnitude of each meter's error before the meter was replaced. The utility's admitted inability to explain the "erratic and high unaccounted for water" concerns us. We find that the test year kgal sold data is irreparably flawed and inappropriate for ratemaking.

We also have an additional concern with the kgal sold data for 2005: Labrador's 2005 test year is also the same year in which the revenue increases and rate structure changes from the utility's last case went into effect. In the utility's last rate case, this Commission granted a 183 percent increase for the water system and a 151 percent increase for the wastewater system. In addition, this Commission changed Labrador's **[*17]** water and wastewater rate structures from non-usage based, flat rate structures, to the current BFC/gallonage charge rate structures. The rates resulting from the fast rate case became effective February 3, 2005 -- the first bill received under the new rates was approximately one month later. Therefore, customers' responses to the revenue and rate structure changes have not been fully captured and reflected in the 2005 test year data.

We believe an attempt to either rehabilitate the current filing by using 2006 kgal sold data or file a new case using 2006 kgal sold data would also yield flawed results. In a letter to our staff dated November 21, 2006, the utility compared January through November kgal sold data for 2005 versus 2006. The utility stated: "As you can see, the difference is less than 1 percent. Thus, there is no legitimate basis to question the 2005 consumption data. Further, the data shows that dismissing the current docket and refiling with a 2006 test year would serve no useful purpose since it would be based upon the same water usage as the current case." While we disagree that there is no basis to question the 2005 consumption data, we agree that refiling with 2006 **[*18]** data would serve no useful purpose. As discussed above, the 2005 kgal sold data appears to be irreparably flawed. If the 2006 kgal sold data is within 1 percent of the corresponding 2005 data, it does not prove the voracity of the 2005 data. Rather, it is an indication that the 2006 kgal sold data is equally flawed. Also, as shown on Table 1, the utility replaced an additional 61 meters during 2006. Although only 4 of the 61 meters actually tested positive for defects, it is unknown how many of the remaining 57 meters that were replaced without being tested were also, in fact, defective. In addition, the defective 6" meter represents a material number of kgal sold. Based on 2005 figures, this meter accounts for approximately 8 percent of the utility's total water sold. Finally, as late as October 30, 2006, the utility has not, by its own admission, been able to find a satisfactory explanation for the "erratic and high unaccounted-for water."

There are two possible scenarios with respect to the flawed data. If the test year kgal sold data is too low, then the resulting rates will, all other things being equal, be overstated. This may possibly cause the utility to overearn in subsequent **[*19]** years. Conversely, if the test year kgal sold data is too high, then the resulting rates will be less than compensatory, which would probably result in a shorter period before the utility files another request for a rate increase. There have been numerous customer complaint letters in this case that specifically mentioned displeasure with Labrador's request for rate relief because it was granted an increase within the past two years. If we were to set noncompensatory rates, we believe this would further perpetuate the frequency of rate case filings by the utility. Therefore, we find that setting rates based on flawed data would be neither fair nor reasonable to the customers or the utility.

Due to the number and nature of the defective meters found during the test year, as well as the timing of the test year coincident with the period when rates from the last rate case went into effect, we are unable to determine the appropriate number of kgal sold by the utility during the test year. This renders us unable to see the entire test year ratemaking picture, both with respect to: a) how many kgal were actually sold (affecting whether the current rates are, in fact, noncompensatory, and, **[*20]** if so, by what magnitude) ; and b) the appropriate number of kgal to use in the design of rates. In *Section 367.081, F.S.*, we are charged with the statutory responsibility of setting rates which are fair and reasonable. It is neither our nor our staff's responsibility to make the utility's case. The burden of proof is upon the utility to show that its present rates are unreasonable, fail to compensate the utility for its prudently incurred expenses, and fail to produce a reasonable return on its investment. [5] Based on the foregoing, we find the utility has failed to meet its burden of proof in this case, in that Labrador has not presented credible evidence regarding the number of kgal actually sold during the 2005 test year, and its 2005 and 2006 kgal sold data are irreparably flawed.

[*21]

Conclusion

In conclusion, the data supplied by Labrador is insufficient to determine the revenue requirement and set reasonable rates. The burden of proof is upon the utility to show that its present rates are unreasonable, fail to compensate the utility for its prudently incurred expenses, and fail to produce a reasonable return on its investment. See *South Florida Natural Gas v. Florida Public Service Commission, 534 So.2d 695 (Fla. 1988)*; *Florida Power Corp. v. Cresse, 413 So.2d 1187, 1191 (Fla. 1982)* (finding that the burden of proof in a Commission proceeding is always on a utility seeking to change, and upon other parties seeking to change established rates); and Order No. 24715, issued June 26, 1991, in Docket No. 900329-WS, In re: Application for rate increase in Citrus, Martin, Marion, and Charlotte/Lee Counties by Southern states Utilities. Inc.; in Collier County by Marco Island Utilities (Deltona) and Marco Shores Utilities (Deltona); in Marion County by Marion Oaks Utilities (united Florida); and in Washington County by Sunny Hills Utilities (United Florida) [See *Southern States Utilities v. Florida Public Service Commission, 602 So.2d 944 (Fla. 1992)* **[*22]** (in which Order No. 24715 was "Per Curiam. Affirmed")].

The burden is on the utility to prove that the requested rate increase is warranted. When a utility fails to establish its entitlement to the relief requested in its petition, we have the authority to deny that petition. *City Gas Company of Florida v. Florida Public Service Commission, 501 So.2d 580 (Fla. 1987)*. Because of the aforementioned inconsistent data, we find the utility has not carried its burden of proof for us to determine just, reasonable, compensatory, and not unfairly discriminatory rates. As such, Labrador's request for a final revenue increase is denied in its entirety in this instant case.

III. Appropriate Water and Wastewater Rates

The utility has not met its burden of proof for this Commission to determine just, reasonable, compensatory, and not unfairly discriminatory rates. Therefore, Labrador shall charge the rates in effect prior to the approval of interim rates. The utility shall file tariff sheets to reflect the appropriate rates. The approved rates are listed below:

Residential -- Water		**General Service -- Water**	
Base Facility Charge:		Base Facility Charge	
5/8" x 3/4"	$ 6.28	5/8"	$ 12.09
Gallonage Charge	$ 9.42	3/4"	$ 18.14
(per 1,000 gallons)	$ 15.70	1"	$ 30.23
General Service -- Water	$ 31.40	1-1/2"	$ 60.45
Base Facility Charge	$ 50.24	2"	$ 96.72

[5] See *South Florida Natural Gas v. Florida Public Service Commission, 534 So. 2d 695 (Fla. 1998)*; ***Florida Power Corporation v. Cresse, 413 So. 2d 1187 (Fla. 1982)***.

Residential -- Water		General Service -- Water	
5/8" x 3/4"	$ 100.48	3"	$ 193.44
3/4"	$ 157.00	4"	$ 302.25
1"	$ 314.00	6"	$ 604.50
1-1/2"	$ 3.14	Gallonage Charge	$ 11.21
2"		(per 1,000 gallons)	
3"			
4"			
6"	$ 50.24		
Gallonage Charge	$ 3.14		
(per 1,000 gallons)			
Irrigation - Water			
Base Facility Charge			
2"			
Gallonage Charge			
(Per 1,000 gallons)			

[*23]

IV. Refund of Interim Revenues

Pursuant to *Section 367.082, F.S.*, revenues collected under interim rates shall be placed under bond, escrow, letter of credit, or corporate undertaking subject to refund with interest at a rate ordered by this Commission. In this case, the total annual interim revenue increase granted in Order No. PSC-06-0668-FOF-WS was $ 45,319 (30.06%) for water and $ 51,294 (14.91%) for wastewater. Our staff calculated the potential refund of revenues and interest collected under interim conditions to be $ 57,183. This amount is based on an estimated seven months of revenues collected from the approved interim rates granted in Order No. PSC-06-0668-FOF-WS. By letter dated August 15, 2006, Labrador filed a corporate undertaking pursuant to the order above. In its interim revenue report dated December 21, 2006, Labrador indicated the interim revenues collected during the period September 2006 through November 2006 was $ 9,809. The interim rates will continue to be collected until the tariffs containing the original rates are approved. Therefore, the total amount of the interim refund cannot be determined at this time.

Because **[*24]** the data supplied by Labrador is insufficient to determine an appropriate revenue requirement and set reasonable rates, we have found that the utility has not met its burden of proof for this Commission to determine just, reasonable, compensatory, and not unfairly discriminatory rates. As such, Labrador shall refund, with interest, all interim revenues collected pursuant to Order No. PSC-06-0668-FOF-WS. Pursuant to Rule 25-30.360(7), F.A.C, Labrador shall file the appropriate refund reports indicating the amount of money to be refunded and how that amount was computed.

V. Show Cause Proceeding

Pursuant to Order No. PSC-04-1281-PAA-WS (PAA Order), this Commission required Labrador to:

(1) adjust its books to reflect the adjustments to all the applicable primary accounts required by that Order and provide proof of such adjustments within 90 days of the issuance date of a final order; and

(2) to test all of its meters by June 30, 2005, make any necessary repairs or adjustments, maintain a log of all meters tested, and file quarterly reports.

That PAA Order was finalized by Consummating Order, Order No. PSC-05-0087-CO-WS, issued **[*25]** January 24, 2005. Therefore, the appropriate adjustments to all the applicable primary accounts should have been accomplished by no later than April 24, 2005. Also, pursuant to the PAA Order, all the meters were originally to have been tested by June 30, 2005, and progress reports were to have been filed on April 15, July 15, and October 15, 2005.

By letter dated April 22, 2005, counsel for Labrador provided a schedule indicating the required adjustments to primary accounts had been made. Also, by letter dated July 15, 2005, counsel for Labrador advised that all meters had been tested except for approximately 150 homes where the homeowners had turned off isolation valves, and that testing on those meters would not be completed until the end of October or early November 2005. Finally, by letter dated June 23, 2006, counsel for Labrador submitted an attached final report of meter flow test results stating that all test results were completed on May 24, 2006.

Although the utility had indicated that all required adjustments to the primary accounts had been made as of April 22, 2005, in processing the current rate case, our staff determined that the required adjustments to plant in service **[*26]** and accumulated depreciation were either not made or not made until December 2005. Therefore, the letter dated April 22, 2005, was incorrect, and it appears that the appropriate adjustments were not made until almost eight months later, i.e., eight months late. Also, it appears that the utility did not complete testing the meters until May 24, 2006, almost eleven months later than required. In reviewing the initial meter report, our staff noted that the dates of testing reflect lest dates from September 2000 through April 2002, some two and one-half years before the PAA Order which required the testing. The utility later moved to correct that report, but it appears that many meters were not tested until well after the June 30, 2005 deadline. Moreover, by letter dated November 22, 2006, the utility states that it tested 799 meters, but did not test the remaining 103 meters. The utility states that these 103 meters were either new meters installed by the utility, which were tested and certified by the manufacturer prior to installation, or meters that the utility was unable to test because they were not connected to a water source.

Utilities are charged with the knowledge of the Commission's **[*27]** rules and statutes. Additionally, "[i]t is a common maxim, familiar to all minds that 'ignorance of the law' will not excuse any person, either civilly or criminally." *Barlow v. United States, 32 U.S. 404, 411 (1833)*. Section 367.161(1), F.S., authorizes this Commission to assess a penalty of not more than $ 5,000 for each offense if a utility is found to have knowingly refused to comply with, or to have willfully violated, any provision of Chapter 367, F.S., or any lawful order of the Commission. By failing to comply with the above-noted requirements of the PAA Order in a timely manner, the utility's acts were "willful" in the sense intended by *Section 367.161, F.S.* In Order No. 24306, issued April 1, 1991, in Docket No. 890216-TL titled In Re: Investigation Into The Proper Application of Rule *25-14.003, F.A.C.*, Relating To Tax Savings Refund for 1988 and 1989 For GTE Florida. Inc., the Commission, having found that the company had not intended to violate the rule, nevertheless found it appropriate to order it to show cause **[*28]** why it should not be fined, stating that "willful" implies an intent to do an act, and this is distinct from an intent to violate a statute or rule. Id. at 6.

We find that the circumstances in this case are such that show cause proceedings shall be initiated. We are especially concerned with Labrador's apparent failure to adjust its books to reflect the adjustments to all the applicable primary accounts as required by the PAA Order. In the Order Approving Settlement Agreement Filed by Utilities, Inc. (Settlement Order), [6] issued December 23, 2004, in Docket No. 040316-WS, the utility specifically agreed that: "Beginning with the year ended December 31, 2003, and continuing through December 31, 2004, UI shall review ail Commission transfer and rate case orders to determine if proper adjustments have been made to correctly state rate base balances." Both the Settlement Order and the PAA Order, issued just five days apart, should have made the utility acutely aware of the problems that it was having in maintaining its books and records. This continued pattern of disregard for our rules, statutes, and orders warrants more than just a warning. Accordingly, Labrador shall be made **[*29]** to show cause in writing, within 21 days, why it should not be fined $

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[6] Order No. PSC-04-1275-AS-WS, in Docket No. 040316-WS, In re: Analysis of Utilities, Inc.'s plan to bring all of its Florida subsidiaries into compliance with Rule *25-30.115, Florida Administrative Code*.

3,000 for its apparent failure to adjust its books to reflect the adjustments to all the applicable primary accounts required by the PAA Order and provide proof of such adjustments within 90 days of the Consummating Order.

Although the utility has apparently not timely complied with the requirement to test all its meters by June 30, 2005, the utility has demonstrated mitigating circumstances. A significant portion of Forest Lake Estates' residents are present only during the winter, and by letter dated July 15, 2005, the utility advised staff that, because the homeowners had turned off their isolation valves and were not in Florida for the summer, it had not yet tested approximately 150 meters. The **[*30]** utility indicated it expected all testing to be done by October or November of 2005. Subsequently, by letter dated June 23, 2006, the utility advised that the testing had been completed as of May 24, 2006, and attached a report. However, the report attached to that letter showed meter test dates from September 2000 through April 2002, over 2'/2 years before there was a requirement for meter tests, and a corrected report was not filed until November 7, 2006. By letter dated November 22, 2006, the utility claims that it tested 799 meters out of a total of 902. Of the remaining 103 meters, the utility states that 73 were new meters which had been tested and certified by the manufacturer prior to installation, with 67 meters being replaced without testing because the owners had shut off the water and the utility was unable to test the existing meter. Of the remaining 30 meters, the utility states that they were on vacant lots and had no service lines, and thus the utility was physically unable to test them.

While a six-month extension to December 30, 2005, might have been warranted, the utility did not request such an extension, and then did not complete the testing until May 24, 2006, **[*31]** which was almost eleven months past the original due date. Moreover, there is some question of whether the 73 new meters should have been retested at installation, and whether the 30 meters on vacant lots should have been tested. Based on all the above, we do not believe the delay in testing the meters was as serious as the utility's failure to adjust its books to reflect the adjustments reflected in the PAA Order, and Labrador shall be made to show cause in writing, within 21 days, why it should not be fined $ 500 for its apparent failure to timely test all its meters by June 30, 2005.

Based on the above, Labrador shall be made to show cause in writing, within 21 days, why it should not be fined a total of $ 3,500 for its apparent failure to timely comply with the two requirements described above in Order No. PSC-04-1281-PAA-WS. The following conditions shall apply:

1. The utility's response to the show cause order shall contain specific allegations of fact and-law;

2. Should Labrador file a timely written response that raises material questions of fact and makes a request for a hearing pursuant to Sections 120.569 and 120.57(1), F.S. **[*32]** , a further proceeding will be scheduled before a final determination of this matter is made;

3. A failure to file a timely written response to the show cause order shall constitute an admission of the facts herein alleged and a waiver of the right to a hearing on this issue;

4. In the event that Labrador fails to file a timely response to the show cause order, the fine shall be deemed assessed with no further action required by the Commission;

5. If the utility responds timely but does not request a hearing, a recommendation shall be presented to the Commission regarding the disposition of the show cause order; and

6. If the utility responds to the show cause order by remitting the fine, this show cause matter shall be considered resolved.

Further, the utility shall be put on notice that failure to comply with Commission orders, rules, or statutes will again subject the utility to show cause proceedings and fines of up to $ 5,000 per day per violation for each day the violation continues as set forth in *Section 367.161, F. S.*

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the application of Labrador Utilities, **[*33]** Inc., for increased water and wastewater rates is denied. It is further

ORDERED that the appropriate rates for Labrador Utilities, Inc., are the rates in effect prior to the approval of interim rates, and the utility shall file revised tariff sheets as shown in the body of this Order. It is further

ORDERED that pursuant to Rule *25-30.360, F.A.C.*, Labrador Utilities, Inc. shall, refund, with interest, the interim revenues granted by Order No. PSC-06-0668-FOF-WS. It is further

ORDERED that Labrador Utilities, Inc., shall be made to show cause in writing, within 21 days, why it should not be fined a total of $ 3,500 for its apparent failure to timely comply with the requirements of Order No. PSC-04-1281-PAA-WS to (1) adjust its books to reflect the adjustments to all the applicable primary accounts required by that Order and provide proof of such adjustments within 90 days of the issuance date of a final order; and (2) to test all of its meters by June 30, 2005, and make any necessary repairs or adjustments, maintain a log of all meters tested, and file quarterly reports. It is further

ORDERED that any response shall comply with the conditions **[*34]** as set forth in the body of this Order and shall be filed with the Director, Division of the Commission Clerk and Administrative Services within 21 days of the date of issuance of this Order. It is further

ORDERED that the provisions of this Order, except for the show cause proceedings, are issued as proposed agency action, and shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule *28-106.201, Florida Administrative Code*, is received by the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that if no person whose substantial interests are affected by the proposed agency action issues files a protest within twenty-one days of the issuance of the Order, a Consummating Order will be issued for the proposed agency action issues. The docket shall remain open for our staff's verification that the revised tariff sheets and customer notice have been filed by the **[*35]** utility and approved by staff, and that the interim refund has been completed. It is further

ORDERED that if Labrador Utilities, Inc. pays the $ 3,500 in fines, the docket shall be closed administratively upon our staffs verification of the above items. If the utility timely responds in writing to the Order to show cause, the docket shall remain open to allow for the appropriate processing of the response.

By ORDER of the Florida Public Service Commission this 14th day of February, 2007.

FL Public Service Commission Decisions

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Potomac Electric Power Co. v. Public Service Com.

District of Columbia Court of Appeals

October 9, 1981, Argued ; February 16, 1983, Decided

Nos. 79-1159, 79-1106

Reporter
457 A.2d 776 *; 1983 D.C. App. LEXIS 325 **

POTOMAC ELECTRIC POWER COMPANY, PETITIONER, v. PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA, RESPONDENT, PEOPLE'S COUNSEL OF THE DISTRICT OF COLUMBIA and WASHINGTON METROPOLITAN AREA TRANSIT AUTHORITY, INTERVENORS

Prior History: [1]** Petition of Appeal from an Opinion and Order of the Public Service Commission of the District of Columbia

Disposition: Affirmed.

Core Terms

permanent, rate of return, emergency, rate increase, rates, emergency relief, earnings, actual rate, second application, first application, initial application, necessary capital, confiscation, interim, reasonable rate, factors, ending, public service, circumstances, ratemaking, electric, investor, unjust

Case Summary

Procedural Posture
Petitioner utility sought judicial review of the orders of respondent Public Service Commission of the District of Columbia, which dismissed two applications for emergency rate relief.

Overview
The utility contested the denial of emergency rate relief by the commission while its application for a permanent rate increase was pending and contended that it was entitled to such relief because its actual rate of return was less than its authorized reasonable rate of return. The court found that the utility showed no evidence of an inability to raise capital or a threat to its public service obligation. The court affirmed the orders of the commission. The court determined that its scope of review was limited to whether the commission's orders were unreasonable, arbitrary, or capricious. Because the utility failed to show that the rate discrepancy met the conditions for emergency rate relief, the court concluded that the commission's decision was not arbitrary. The court ruled that the rate discrepancy was not a confiscation because the authorized rate of return was not a guarantee of a specific rate of return in the future. With no new evidence presented in the utility's second application, the court found no error in its dismissal without a hearing.

Outcome
The court affirmed the orders of the commission that dismissed the utility's applications for emergency rate relief.

LexisNexis® Headnotes

Administrative Law > Judicial Review > General Overview

Energy & Utilities Law > Utility Companies > Rates > General Overview

Administrative Law > Judicial Review > Reviewability > Factual Determinations

Administrative Law > Judicial Review > Reviewability > Jurisdiction & Venue

Administrative Law > Judicial Review > Standards of Review > General Overview

Administrative Law > Judicial Review > Standards of Review > Arbitrary & Capricious Standard of Review

Energy & Utilities Law > Administrative Proceedings > General Overview

Energy & Utilities Law > Administrative Proceedings > Judicial Review > General Overview

Energy & Utilities Law > ... > Public Utility Commissions > Hearings & Orders > Judicial Review

Energy & Utilities Law > Electric Power Industry > State Regulation > General Overview

HN1[] **Administrative Law, Judicial Review**

The court has jurisdiction to hear appeals from an order or decision of the Public Service Commission of the District of Columbia. D.C. Code Ann. § 43-905 (1981). The court's scope of review is limited to questions of law, including constitutional questions, and the findings of fact by the commission shall be conclusive unless it shall appear that such findings of the commission are unreasonable, arbitrary or capricious. D.C. Code Ann. § 43-906 (1981). The court's scope of review of the commission's orders is the narrowest judicial review in the field of administrative law. While the court must ascertain that, in striking a balance between the competing consumer and investor interests, the commission has given reasoned consideration to each of the pertinent factors, the court must not substitute its judgment for that of the commission. Even though the court might arrive at a somewhat different decision than did the commission, if there is substantial evidence to support the commission's findings and conclusions and the commission has given reasoned consideration to each of the pertinent factors, the court must affirm.

Energy & Utilities Law > Administrative Proceedings > Judicial Review > General Overview

HN2[] **Administrative Proceedings, Judicial Review**

It is the "total effect" of a rate order, rather than the methodology employed, that determines the validity of the order. Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling. It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry is at an end. The fact that the method employed to reach that result may contain infirmities is not then important.

Administrative Law > Judicial Review > General Overview

Energy & Utilities Law > Utility Companies > Rates > General Overview

Administrative Law > Agency Adjudication > Decisions > Contents

Energy & Utilities Law > Administrative Proceedings > General Overview

Energy & Utilities Law > Administrative Proceedings > Judicial Review > General Overview

Energy & Utilities Law > ... > Public Utility Commissions > Hearings & Orders > Judicial Review

HN3[] **Administrative Law, Judicial Review**

In order to ensure meaningful judicial review, the court has imposed an independent burden on the public utility commission to explain its actions fully and clearly, by (1) announcing the criteria governing its determination, and (2) explaining how the particular order reflects application of these criteria to the facts of the case. These additional do not detract from the presumptive validity of commission rate orders. The petitioner challenging an order carries the heavy burden of demonstrating clearly and convincingly a fatal flaw in the action taken. Even if the court disagrees with the commission, if the commission has fully and clearly explained what it does and why it does it, and the agency decision is supported by substantial evidence, the court, upon a finding that the commission order is reasonable in its overall effect, must sustain the order.

Energy & Utilities Law > Regulators > Public Utility Commissions > Authorities & Powers

Energy & Utilities Law > Regulators > Public Utility Commissions > General Overview

Energy & Utilities Law > ... > Rates > Ratemaking Factors > Rate of Return

HN4[] **Public Utility Commissions, Authorities &**

Powers

The public utility commission has consistently articulated three sets of circumstances which may serve as a basis for granting emergency rate relief. These circumstances, which comport with emergency ratemaking criteria in other jurisdictions, may be summarized as follows: (1) a present or clearly imminent threat that the utility will be unable to continue meeting its public service obligation; (2) a present or clearly imminent threat that the utility will be unable to obtain necessary capital funds to finance the construction of necessary new or replacement plant; (3) the utility is experiencing earnings which produce a rate of return substantially less than that which is reasonable.

Administrative Law > Agency Adjudication > Decisions > Res Judicata

Civil Procedure > Judgments > Preclusion of Judgments > Res Judicata

Energy & Utilities Law > ... > Rates > Ratemaking Factors > Rate of Return

Civil Procedure > Judgments > Preclusion of Judgments > General Overview

Energy & Utilities Law > Regulators > Public Utility Commissions > General Overview

HN5[] **Decisions, Res Judicata**

As a matter of law, nothing requires the public utility commission to use its previously authorized rate of return as the sole indicator of the utility's present "reasonable rate of return". Given certain circumstances, it may be useful for the commission to adhere to a prior rate of return finding as an appropriate standard against which to measure a utility's need for immediate emergency relief. Yet, the prior determination made in the context of a different case and on the basis of different test year data is not res judicata as to the authorized rate of return in the context of a new case concerning a different time period.

Energy & Utilities Law > Regulators > Public Utility Commissions > General Overview

Energy & Utilities Law > ... > Rates > Ratemaking Factors > Rate of Return

HN6[] **Regulators, Public Utility Commissions**

An actual rate of return that is lower than the most recent previously authorized rate of return is not per se unjust or unreasonable. The risk that a utility's own inefficiency or external business may prevent the utility from achieving a specified rate of return is allocated to the utility. The mere failure to earn a previously authorized rate of return imposes no obligation upon the public utility commission to grant a rate increase.

Energy & Utilities Law > Regulators > Public Utility Commissions > Authorities & Powers

Governments > Local Governments > Administrative Boards

Energy & Utilities Law > Regulators > Public Utility Commissions > General Overview

HN7[] **Public Utility Commissions, Authorities & Powers**

The public utility commission has the power to dismiss an application without a hearing. A hearing is not necessary where no material facts are in dispute or where the disposition of claims turn not on the determination of facts, but inferences and legal conclusions to be derived from facts already established.

Counsel: William Dana Shapiro, General Counsel, with whom Edward A. Caine, William C. Gardner and Betty K. Cauley were on the briefs, for petitioner.

Lloyd N. Moore, General Counsel, with whom Judith W. Rogers, Corporation Counsel, Richard W. Barton, Deputy Corporation Counsel at time brief was filed, and Melvin J. Washington, Assistant Corporation Counsel, were on the brief, for respondent.

Elizabeth A. Noel, Assistant People's Counsel, with whom Brian Lederer, People's Counsel, was on the brief, for intervenor People's Counsel.

Onkar N. Sharma, Assistant General Counsel, was on the brief for intervenor Washington Metropolitan Area Transit Authority.

Judges: Newman, Chief Judge, and Kelly and Nebeker, Associate Judges. Opinion for the court by Chief Judge Newman. Dissenting opinion by Associate Judge Nebeker.

Opinion by: NEWMAN

Opinion

[*779] The Public Service Commission of the District of Columbia (Commission) denied two applications submitted by the Potomac Electric Power Company (PEPCO) **[*780]** for emergency rate relief. [1] In this consolidated appeal, **[**2]** PEPCO raises numerous objections to these decisions. It contends that the Commission's refusal to order an emergency increase in electric rates was arbitrary and constituted an unconstitutional confiscation of property. Additionally, PEPCO claims that it was improper for the Commission to evaluate its applications in light of the Company's overall financial situation, rather than only earnings on its District of Columbia operations. Finally, PEPCO complains that it was denied procedural due process by the Commission's dismissal of its second emergency rate relief application without a hearing. PEPCO asks this court to order the Commission to authorize a temporary rate surcharge enabling it to collect the revenues it would have gained had the Commission granted the requested emergency rate relief. We find PEPCO's arguments unpersuasive and affirm the Commission's orders.

[3]** I. BACKGROUND AND PROCEDURAL HISTORY

This case involves retail electric rates in the District of Columbia between June 1979 and May 1980. In June 1979, PEPCO filed an initial application for an emergency increase in its charges for electric service within the District of Columbia. PEPCO proposed to collect this increase subject to refund pending final decision on its related application for a permanent rate increase. In May 1980, the Commission granted PEPCO a permanent rate increase pursuant to the related application, thereby alleviating PEPCO's alleged emergency. PEPCO now seeks to recapture the revenue to which it argues it was entitled for the period from August 17, 1979, when the Commission denied PEPCO's initial request for emergency rate relief, to May 31, 1980, when the permanent rate increase went into effect. [2]

A summary **[**4]** of PEPCO's recent rate history is essential for a complete understanding of the issues. In November 1975, the Commission granted PEPCO a permanent increase in retail rates of $27,657,000. Immediately thereafter in December 1975, PEPCO filed another application which, as amended, requested a permanent rate increase of $57,578,000. In December 1976, as a result of this application, PEPCO received a $29,411,000 permanent rate increase.

In July 1977, PEPCO filed another application for a permanent increase which was considered by the Commission in Formal Case 685. As amended, this application sought to increase the Company's annual gross operating revenues by approximately $44.9 million. This request was based on 1977 test year data. While this case was still pending, PEPCO filed another permanent rate increase application. This application, considered in Formal Case 715, initially sought an annual increase in retail rates of $15,464,000.

On June 14, 1979, the Commission issued a proposed order in Formal Case 685 (Order No. 6096). It recommended that PEPCO be allowed to receive a 9.03% rate of return [3] **[*781]** through a permanent rate

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[1] PEPCO's applications for relief were styled as applications for "immediate emergency rate relief." Subsequently, the applications have been referred to by the parties as applications for "temporary rate relief," "interim rate relief," or "emergency rate relief." Under District of Columbia law, the terms are interchangeable. They all refer to a request for the expedited imposition of a rate increase that is subject to refund depending on the disposition of a related application for a permanent rate increase. This court has upheld the Commission's power to issue such a rate increase as a power implied from the Commission's specifically granted statutory powers. *Chesapeake & Potomac Telephone Co. v. Public Serv. Comm'n, D.C.App., 330 A.2d 236, 240 (1974)*.

[2] PEPCO does not seek to recapture any revenue for the period covered by its first application for emergency rate relief, *i.e.*, from June 21, 1979 to August 17, 1979.

[3] The Company's authorized overall rate of return is determined by the "cost of capital" method. That method seeks to determine what return the Company must offer its investors in order to attract the capital investment in its stocks and bonds necessary to finance its construction and operations. *See Re Potomac Elec. Power Co., 29 PUR4th 517, 521 (D.C.P.S.C. 1979)*. *See also Sun City Water Co. v. Arizona Corp. Comm'n, 26 Ariz. App. 304, , 547 P.2d 1104,*

increase of approximately $5.8 million. **[**5]** A day later, the Commission allowed PEPCO to begin collecting this proposed revenue increase pending the issuance of a final order. The final order essentially adopted the proposals of Order 6096 by authorizing a permanent rate increase of $5,890,000.

[6]** The authorized increase in Formal Case 685 was significantly less than the requested rate increase of $44.9 million. Thus, in July 1979, PEPCO revised its application for new permanent rates in Formal Case 715 to request an increase in revenues of approximately $48.1 million over the revenue level authorized in Case 685. Additionally, before the final order in Case 685 was issued, PEPCO filed its initial application for emergency rate relief as part of Case 715. This application, as amended, sought an immediate $22,945,000 rate increase pending the disposition of its application for new permanent rates.

Therefore, in July 1979, shortly after the completion of Formal Case 685, PEPCO had two outstanding applications for rate relief. A primary application sought a permanent rate increase of $48,079,000 in annual revenue based on a test year ending June 1979. An emergency rate application sought the immediate authorization of $22,945,000 of that $48.1 million.

This application for emergency rate relief was the subject of a Commission hearing in July 1979, before any hearings were held in the connected permanent rate case. [4] The Commission took testimony from PEPCO officials and **[**7]** heard oral argument on motions to dismiss filed by intervenors Washington Metropolitan Area Transit Authority, the General Services Administration, the Office of People's Counsel, and the Commission **[*782]** staff. On August 17, 1979, the Commission issued Order and Opinion 7020 granting the motions to dismiss. The Commission found that PEPCO's allegations, even if taken as proven, failed to demonstrate the extraordinary circumstances necessary to establish a *prima facie* case for emergency relief. After their motion for expedited reconsideration was denied, PEPCO filed a second application for emergency relief on August 27, 1979. The Commission directed PEPCO to submit "a list of factual and legal grounds relied on in the second application that were

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1109-10, *vacated on other grounds*, 113 Ariz. 464, 556 P.2d 1126 (1976) (en banc); City of Evansville v. Southern Ind. Gas & Elec. Co., 167 Ind. App. 472, , 339 N.E.2d 562, 569-70 (1975); In re Southwestern Bell Tel. Co., 10 PUR4th 323, 328-29 (Ark. P.S.C. 1975); In re Southern Conn. Gas Co., 24 PUR4th 162, 194 (Conn. Pub. Utils. Control Auth. 1978).

> The rate of return is an expression, in terms of percentage of rate base, of: ". . . the amount of money a utility earns, over and above operating expenses, depreciation expense, and taxes, expressed as a percentage of the legally established net valuation of utility property, the rate base. Included in the 'return' are interest on . . . debt, dividends on preferred stock, and earnings on common stock equity. In other words, the return is that money earned from operations which is available for distribution among the various classes of contributors of money capital . . . ." [Re Potomac Elec. Power Co., 29 PUR4th at 521-22 (quoting P. GARFIELD & W. LOVEJOY, PUBLIC UTILITY ECONOMICS 116 (1974)).]

The overall cost of a utility's capital is calculated by determining the cost of each component in the company's capital structure. A weighted cost for each component is derived by multiplying its cost by its ratio to total capital. The sum of these weighted costs then becomes the utility's overall rate of return, which is multiplied by the company's rate base to determine the company's revenue requirement. *See id.*

[4] The Commission generally divides hearings on a company's permanent rate increase application into two phases. Phase I is devoted to the determination of the overall revenue requirements of the company for its District operations. The Commission sets an "authorized" rate of return during Phase I, and determines whether existing rates are unjust and unreasonable. In Phase II, the Commission determines a rate structure that fairly allocates the proposed revenue increase among the various classes of consumers so as to provide the required revenue.

The Commission has usually granted emergency rate increases only after Phase I hearings were completed. *See, e.g., In re Washington Gas Light Co.*, PSC Order No. 5517 (June 26, 1972); *Re Pepco*, 82 PUR3d 209, 212 (D.C.P.S.C. 1970); *In re Chesapeake & Potomac Tel. Co.*, PSC Order No. 5644 (May 10, 1974), *aff'd* in *Chesapeake and Potomac Tel. Co. v. Public Serv. Comm'n, supra*. In this manner, the Commission can ensure that the company has satisfied its burden of showing entitlement to higher rates. This practice also ensures that consumers are allowed a full and fair opportunity to test the company's case as to the reasonableness of the rates. In only one case has the Commission found conditions to be so damaging to the company that it granted emergency relief prior to the completion of Phase I hearings. *See In re Washington Gas Light Co.*, PSC Order 5655 (July 11, 1974).

The Commission held a formal hearing on PEPCO's emergency rate application prior to its Phase I hearings in Formal Case 715 in response to PEPCO's motion for expedited consideration of this emergency application.

not similarly advanced" in the first application. After PEPCO responded, the Commission dismissed the second application without a hearing. PEPCO appealed each dismissal separately. The appeals were consolidated by a prior order of this court.

[8]** Thus, after the Commission's dismissals of PEPCO's emergency relief applications, PEPCO continued to operate under the rate structure established in Formal Case 685 until a permanent $35.5 million rate increase was granted in Formal Case 715. (Opinion and Order 7135, May 15, 1980). In an unpublished order denying respondent's motion to dismiss, this court has decided that the permanent rate increase granted PEPCO in Formal Case 715 does not render the present appeals moot.

II. SCOPE OF REVIEW

HN1[] This court has jurisdiction to hear appeals from an order or decision of the Public Service Commission of the District of Columbia. D.C. Code 1981, § 43-905. Our scope of review is, however, "limited to questions of law, including constitutional questions, and the findings of fact by the Commission shall be conclusive unless it shall appear that such findings of the Commission are unreasonable, arbitrary or capricious." D.C. Code 1981, § 43-906. *See, e.g., Metropolitan Washington Board of Trade v. Public Service Commission, D.C.App., 432 A.2d 343, 351 (1981)*; *Potomac Electric Power Co. v. Public Service Commission, D.C.App., 402 A.2d 14, 17* (en banc), *cert. denied*, *444 U.S.* ***[**9]*** *926, 100 S. Ct. 265, 62 L. Ed. 2d 182 (1979)*; *People's Counsel v. Public Service Commission, D.C.App., 399 A.2d 43, 45 (1979)*; *Washington Public Interest Organization v. Public Service Commission, D.C.App., 393 A.2d 71, 75 (1978)*, *cert. denied*, *444 U.S. 926, 100 S. Ct. 265, 62 L. Ed. 2d 182 (1979)*.

Our scope of review of public utility commission orders is the narrowest judicial review in the field of administrative law. *Potomac Electric Power Co. v. Public Service Commission, supra at 17*. This is because Congress vested the sole ratemaking authority in the expertise of the Public Service Commission. The Commission, not this court, has the sole responsibility for balancing consumer and investor interests in designing rate structures and approving specific charges. D.C. Code 1981, §§ 43-501, -601, -611; *People's Counsel v. Public Service Commission, supra.* While we must ascertain that, in striking a balance between the competing consumer and investor interests, "the Commission has given reasoned consideration to each of the pertinent factors," *id. at 45-46* (quoting *Permian Basin Area Rate Cases, 390 U.S. 747, 792, 88 S. Ct. 1344, 20 L. Ed. 2d 312 (1968))*, **[**10]** we must not substitute our judgment for that of the Commission. *Metropolitan Washington Board of Trade v. Public Service Commission, supra at 352*; *accord* *Permian Basin Area Rate Cases, supra at 792*; *Potomac Electric Power Co. v. Public Service Commission, supra at 18*. Even though we might arrive at a somewhat different decision than did the Commission, if there is substantial evidence to support the Commission's findings and conclusions and the Commission has given reasoned consideration to each of the pertinent factors, we must affirm. *Permian Basin Area Rate Cases, supra at 792*; *Potomac Electric Power Company v. Public Service Commission, supra at 17*; *Williams v. Washington Metropolitan Area Transit Commission, 134 U.S.App. D.C. 342, 362, 415 F.2d 922, 942 (1968)*, *cert. denied*, *393 U.S. 1081, 21 L. Ed. 2d 773, 89 S. Ct. 860 (1969)*.

[*783] Indeed, the Supreme Court has established that ***HN2***[] it is the "total effect" of a rate order, rather than the methodology employed, that determines the validity of the order.

> Under the statutory standard of "just and reasonable" it is the result reached not the method employed which is controlling . . . . It **[**11]** is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry . . . is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. [*Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 602, 88 L. Ed. 333, 64 S. Ct. 281 (1944)* (citations omitted).]

This standard was held applicable to the District of Columbia Public Service Commission in *Washington Public Interest Organization v. Public Service Commission, supra at 75*:

> These statutory criteria [D.C. Code 1973, §§ 43-301, -401, -411, -705, -706] are akin to those governing the Federal Power Commission and its oversight by the federal courts. In that context, the Supreme Court has held that unless the overall effect of a rate is "unjust and unreasonable," the Commission's order should be approved, irrespective of "infirmities" in the methodology used to calculate it.

Accord *Metropolitan Washington Board of Trade v. Public Service Commission, supra at 351*.

HN3[] In order to ensure meaningful judicial review, [5] we have imposed an independent **[**12]** burden on the Commission to explain its actions fully and clearly, by (1) announcing the criteria governing its determination, and (2) explaining how the particular order reflects application of these criteria to the facts of the case. *Washington Public Interest Organization v. Public Service Commission, supra at 76, 77*. The additional requirements imposed on the Commission by *Washington Public Interest Organization v. Public Service Commission* do not detract, though, from the presumptive validity of Commission rate orders. The petitioner challenging an order carries the heavy burden of demonstrating clearly and convincingly a fatal flaw in the action taken. *Federal Power Commission v. Hope Natural Gas Co., supra at 602*; *Metropolitan Washington Board of Trade v. Public Service Commission, supra at 352*; *Potomac Electric Power Co. v. Public Service Commission, supra at 18*; *Goodman v. Public Service Commission, D.C.App., 309 A.2d 97, 101 (1973)*. Even if the court disagrees with the Commission, if the Commission has fully and clearly explained **[*784]** what it does and why it does it, and the agency decision is supported by substantial evidence, the court, **[**13]** upon a finding that the Commission order is reasonable in its overall effect, must sustain the order. *Washington Gas Light Co. v. Public Service Commission, D.C.App., 450 A.2d 1187 (1982)*.

[14]** We are further mindful that we are reviewing a denial of a utility's request for emergency rate relief rather than the components of a permanent rate order. Important differences between the two proceedings dictate an even more limited role for this court when emergency relief is at issue. In the first place, we are reviewing an administrative inquiry whose purpose and consequences are much more limited than permanent ratemaking. Permanent ratemaking requires the Commission to set new rates, after detailed consideration of the appropriate test year, the property to be included in the rate base, and the fair and reasonable rate of return, that will be effective for an indeterminate future period. In deciding an emergency rate application, the Commission is merely deciding whether or not the utility's financial situation warrants granting a portion of a permanent rate request in advance of actually establishing new permanent rates. Moreover, the Commission's power to grant emergency rate relief derives from an implied rather than express statutory power. This court has, therefore, advised the Commission that it should exercise its power to grant emergency relief with restraint. **[**15]** *Chesapeake and Potomac Telephone Co. v. Public Service Commission, supra at 243*. Having so advised the Commission, we should exercise equal restraint in overturning their expert judgment in denying this form of rate relief.

We approach petitioner's arguments with the foregoing principles in mind.

III. THE COMMISSION'S APPLICATION OF ITS CRITERIA FOR GRANTING EMERGENCY RATE INCREASE

HN4[] The Commission has consistently articulated three sets of circumstances which may serve as a basis for granting emergency rate relief. These circumstances, which comport with emergency ratemaking criteria in other jurisdictions, [6] **[**16]** may

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[5] In *Washington Public Interest Organization v. Public Service Commission, supra*, we clarified our role as a reviewing court in light of the broad authority allotted the Commission under *Federal Power Commission v. Hope Natural Gas Co.* and its progeny:

> While it is true that a regulatory commission cannot be faulted for its methodology if the "total effect of the rate order cannot be said to be unjust and unreasonable," *Federal Power Comm'n v. Hope Natural Gas Co.* [*320 U.S. at 602*], it is also true that the methodology must be disclosed for the bearing it may have on that overall judgment. Absent precise explanation of methodology as applied to the facts of the case, there is no way for a court to tell whether the Commission, however expert, has been arbitrary or unreasonable. [*Washington Public Interest Organization v. Public Service Commission, 393 A.2d at 76-77*.]

This requirement is intended to assist the reviewing court:

> Because ratemaking is complicated and understandably prone to technical, often shorthand terminology, there is a substantial risk that agency action will be too conclusional -- not elaborate enough -- for a non-expert court confidently to review. A court, without insisting on more precise explanation, could simply be fooled into accepting arbitrary agency action by the mesmerizing influence of the confidently expressed language of experts.
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> * * *
>
> While our own authority is . . . limited, our authority -- and responsibility -- to find out why an agency acts as it does is considerable. [*Id. at 78, 79*.]

[6] *See, e.g.*, *Re Jersey Central Power & Light Co., 38 PUR4th 115, 117* (New Jersey Board of Public Utilities 1980); *Re*

be summarized [7] as follows: (1) a present or clearly imminent threat that the Company **[*785]** will be unable to continue meeting its public service obligation; (2) a present or clearly imminent threat that the Company will be unable to obtain necessary capital funds to finance the construction of necessary new or replacement plant; (3) the Company is experiencing earnings which produce a rate of return substantially less than that which is reasonable.

[17]** PEPCO maintains that it satisfied these factors insofar as its initial application demonstrated that it was earning a rate of return substantially less than that which was reasonable. PEPCO's initial application alleged: (1) PEPCO's actual rate of return on its District of Columbia rate base for the twelve month period ending April 30, 1979 was 7.72%; [8] (2) the Commission had found in Formal Case 685 that, on the basis of a 1977 test year, a reasonable rate of return for PEPCO was 9.03%; (3) the deficiency constitutes a "financial emergency" entitling it to an immediate rate increase of $22.9 million, the amount necessary for it to earn a return of 9.03%.

[18]** The Commission correctly found that PEPCO failed to indicate any circumstances, other than the discrepancy between actual and authorized rates of return, which could prove an emergency need for rate relief. Nowhere in its first application did PEPCO present any other facts relating to a potential inability to raise necessary capital. [9] **[**19]** Nor did PEPCO present information in its initial application concerning a threat to its ability to meet its public service obligation. At the hearing held pursuant to PEPCO's initial application, the only testimony given by PEPCO officials that even mentions these two factors is based solely on PEPCO's alleged failure to earn its "authorized" rate of return. [10] In effect, PEPCO's first application alleged

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Washington Water Power Co., 22 PUR4th 485, 488 (Idaho Public Utilities Commission 1977); Re Upper Peninsula Power Co., 25 PUR4th 411, 414 (Michigan 1978); *Re Illinois Power & Light Co.*, Order # 58-907, June 14, 1974 (Illinois). For emergency ratemaking criteria in Ohio, *see* Bloomfield, *Emergency Rate Making for Ohio Public Utilities*, 37 OHIO ST. L.J. 108 (1976). For emergency ratemaking criteria in Missouri, *see* State ex rel. Laclede Gas Co. v. P.S.C., 535 S.W.2d 561 (Mo. App. 1976).

[7] The three factors were set forth originally in Commission Order 5707, Re Potomac Electric Power Co., 9 PUR4th 363, 365 (D.C.P.S.C. 1975), as follows:

> The central issue then, is to identify those factors and circumstances which the company faces that are so critical that they justify the possible abridgement of the usual procedural rights of the parties and justify administrative action on what might be otherwise considered to be a less than adequate record.
>
> A review of our previous decisions indicates such circumstances as: (1) a present or clearly imminent threat that the company will be unable to continue meeting its public service obligation and, (2) a present or clearly imminent threat that the company will be unable to obtain necessary capital funds (to finance the construction of necessary new or replacement plant), see Re Potomac Electric Power Co. (DC 1970) 83 PUR3d 209; Re Washington Gas Light Co. (DC 1972) Order No. 5517; Re Washington Gas Light Co. (DC 1972) Order No. 5655. We would also add that earnings which produce a rate of return substantially less than that which is reasonable may warrant consideration of interim relief. However, the mere failure of a company to realize a previously authorized rate of return or a Phase I finding by the commission that the existing rate of return is less than reasonable is not sufficient in and of itself to warrant interim relief. See Re Potomac Electric Power Co. (DC 1972) 95 PUR3d 99. Neither is the allegation of potential difficulty in raising needed capital on the most favorable terms adequate, in and of itself, to justify relief, see Re Potomac Electric Power Co. (DC 1969) Order No. 5402.

[8] The data accompanying PEPCO's initial application for emergency relief indicated that for the twelve month period ending April 30, 1979, PEPCO's return on its District of Columbia rate base was 6.86%. As adjusted to conform with the conclusions set forth in the Commission's final order in Formal Case 685, and assuming the 5.89 million increase granted in that case had been in effect for the entire twelve month period ending in April, PEPCO's return would have been 7.72%. This later figure is consistently cited by the parties as PEPCO's actual rate of return for the period ending April 30, 1979.

[9] On the contrary, testimony and supplemental filings to the first application show that PEPCO was able to raise necessary capital and that its financial status was secure. *See infra*, slip op. at pp. 20-21.

[10] In the hearing held on Pepco's initial application, the only mention of the Company's inability to raise capital appears in the following testimony of W. Reid Thompson:

> A statement was made by counsel for the staff that PEPCO was seeking a guaranteed rate of return. I would say to the Commission, as the figures show filed here, if this application is today granted in full, effective August 1, our figures show an *anticipated return* of 7.96 for the year 1979, still in our view substantially less than the reasonable return found by this Commission.

that simply because it was experiencing earnings which produced less than its previously "authorized" rate of return, it was also threatened with an inability to meet its public service obligation and to raise necessary capital.

While the Commission considered dismissing the initial application because PEPCO failed to direct its application to the first **[**20]** two factors, it proceeded to address and reject PEPCO's contention that it was entitled to relief because it met the third factor. In this regard, the Commission ruled that it was inappropriate to use the previously authorized rate of return as the presumptively reasonable rate of return for purposes of comparison in this case. Additionally, even accepting 9.03% as an appropriate benchmark, the Commission found that the comparison between this rate and the rate actually being earned by PEPCO failed to demonstrate the necessity of extraordinary **[*786]** action in the form of emergency relief.

HN5[] As a matter of law, nothing requires the Commission to use its previously authorized rate of return as the sole indicator of PEPCO's present "reasonable rate of return". Given certain circumstances, it may be useful for the Commission to adhere to a prior rate of return finding as an appropriate standard against which to measure a utility's need for immediate emergency relief. *See, e.g., In re Washington Gas Light Co.*, PSC Order No. 5666 (July 11, 1974). Yet, the prior determination made in the context of a different case and on the basis of different test year data is not *res judicata* **[**21]** as to the authorized rate of return in the context of a new case concerning a different time period. *State ex rel. Utilities Commission v. Duke Power Company, 285 N.C. 377, , 206 S.E.2d 269, 281 (1974)*; *New England Telephone & Telegraph Co. v. Public Utilities Commission, 354 A.2d 753, 768-70 (Me. 1976)*. Thus, it was not error for the Commission to rule that its previous rate of return decision was not the benchmark of reasonableness as PEPCO alleged.

Even assuming that it was bound by its prior decision concerning authorized rate of return, the Commission found that the actual rate of return experienced by PEPCO was not so substantially less than reasonable so as to constitute an emergency. We cannot say that this decision was arbitrary and capricious. There is no evidence other than a 1.31% gap between a previously authorized rate of return and a present actual rate of return that indicates emergency conditions. Where the Commission has previously granted emergency relief, the discrepancy between authorized and actual rates of return had resulted in severe difficulties for the utility not present in the record of this case. *See Re Potomac Electric Power Co.* **[**22]** , 82 PUR3d 209 (D.C.P.S.C. 1970) (PEPCO experiencing recurrent difficulties in generating sufficient power to meet peak demand; brownouts and voltage reductions had occurred); *In re Washington Gas Light Co.*, PSC Order No. 5655 (July 11, 1974) (WGL actual rate of return was 4.50% as compared to an authorized rate of return of 8.23%; bond and preferred stock coverages were below legally required levels and earnings had been below dividend rate for substantial period). Further, there is no evidence in this case that the 1.31% gap between the authorized and actual rates of return had or would have any such debilitating effects. As the Commission has previously indicated, it is not the purpose of emergency rate relief simply to close the gap between a return previously authorized and actual earnings. Rather, the purpose of emergency relief is to alleviate financial problems whose correction cannot safely await a decision on the proper level of permanent rates. Thus, the Commission has previously denied emergency relief where the discrepancy between the actual and authorized rate of return was more substantial than in this case. *See Re Potomac Electric Power Co.*, 95 PUR3d 99 **[**23]** (D.C.P.S.C. 1972) (emergency relief denied when actual rate of return was 6.65% as compared to previously authorized rate of return of 7.84%); *Re Chesapeake and Potomac Telephone Co.*, 95 PUR3d 339 (D.C.P.S.C. 1972) (emergency relief denied where actual rate of return was 5.80% compared to previously authorized rate of 8.50%); *In re Washington Gas Light Co.*, PSC Order No. 5627 (Feb. 14, 1974) (Emergency relief denied where actual rate of return was 5.19% as compared to previously authorized rate of 8.23%).

IV. CONFISCATION OF PEPCO PROPERTY

The structure of PEPCO's proof of confiscation is the same as its proof that the Commission violated its statutory mandate by denying emergency rate relief. PEPCO presented to the Commission expense and

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> Now, I say to the Commission that the application of these facts alleged here show that there is, show that presently, that this utility is unable to obtain necessary capital funds on a *reasonable basis* to finance the continued construction necessary to serve its customers *based on these* results.

In fact, PEPCO seems to have had little difficulty raising capital. *See infra*, slip op. at pp. 20-21.

revenue data based upon the test year ending April 30, 1979, to which it applied the principles utilized by the Commission in its most recent permanent rate order determination. The results established that PEPCO was actually earning **[*787]** only a 7.72% rate of return under those permanent rates for the adjusted test year. To the extent that this rate of return was less than the rate of return which the Commission had authorized **[**24]** in its most recent order relating to permanent rates, PEPCO claimed that it had proven, *ipso facto*, that it was suffering confiscation. We are satisfied that the Commission did not err in rejecting this argument. We so conclude because we reject the validity of the foundational premise upon which PEPCO's claim of confiscation rests: that the 9.03% fair rate of return authorized by the Commission in establishing permanent rates in Formal Case 685, represents the minimum non-confiscatory rate of return for PEPCO during the period before new permanent rates are established. A utility is authorized to earn a rate of return; it is not guaranteed a specific rate of return for all future periods. *Chesapeake & Potomac Telephone Co. v. Public Service Commission, supra at 242*. **HN6**[] Thus, an actual rate of return that is lower than the most recent previously authorized rate of return is not *per se* unjust or unreasonable. *Mountain States Telephone & Telegraph Co. v. Public Utilities Commission, 345 F. Supp. 80 (D. Colo. 1972)*; *South Central Bell Telephone Co. v. Louisiana Public Service Commission, 272 So.2d 667 (La. 1973)*; *New England Telephone & Telegraph Co. v. Public **[**25]** Service Commission, supra*; *State ex rel. Laclede Gas Co. v. Public Service Commission, 535 S.W. 2d 561 (Mo. App. 1976)*, *Contra* *Southern Bell Telephone & Telegraph Co. v. Bevis, 279 So.2d 285 (Fla. 1973)*. The risk that its own inefficiency or external business may prevent the utility from achieving a specified rate of return is allocated to PEPCO. [11] *Chesapeake & Potomac Telephone Co. v. Public Service Commission, supra at 242*. The mere failure to earn a previously authorized rate of return imposes no obligation upon the Commission to grant a rate increase.

[26]** In other words, the question of whether PEPCO's rates are unjust and unreasonable does not depend on the degree of difference between the actual and previously authorized rates of return. Under the Public Service Commission Law, D.C. Code 1981, § 43-301, *et seq.*, and the *fifth amendment to the United States Constitution*, the District of Columbia Public Service Commission is required to establish utility rates which are "reasonable, just and non-discriminatory." The Commission is not required to adopt as "just and reasonable" any particular rate level. Rather, this constitutional and statutory mandate allows the Commission broad discretion to set rates, without judicial interference, provided that the rates fall within a "zone of reasonableness." [12] *Metropolitan Washington **[*788]** at 350-52*. *See also* *In re Permian Basin Area Rate Cases, supra at 767*; *Washington Gas Light Co. v. Baker, 88 U.S.App.D.C. 115, 119, 188 F.2d 11, 15 (1950)*, *cert. denied*, *340 U.S. 952, 95 L. Ed. 686, 71 S. Ct. 571*, *appeal after remand*, *90 U.S.App.D.C. 98, 195 F.2d 29 (1951)*. Thus, the question of confiscation must

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[11] Some jurisdictions provide the utilities with an entitlement to interim or emergency rate relief whenever earnings fall below a previously authorized rate of return. *See, e.g.*, MD. ANN. CODE, art. 78, § 69B (1980); *FLA. STAT. § 366.06(4)*. Yet, neither this jurisdiction's present law nor the Fifth Amendment entitle the utilities to increased revenues on this basis.

This is not to say that we are unconcerned about the effect of regulatory lag on a utility's earnings pending the disposition of its permanent rate application. Rather, we think that the existing protections are constitutionally adequate. The Commission has pledged to remedy interim revenue deficiencies that threaten the utility's ability to raise necessary capital or meet its public service obligation pending Commission decisions on permanent rates. Furthermore, the Commission has pledged to consider the revenue deficiency problem when establishing new permanent rates. As the Commission stated when it denied PEPCO's second application for emergency relief:

> . . . the appropriate avenue of relief for PEPCO's claim of a failure or inability to earn the return authorized in Formal Case 685 is the prosecution of its permanent rate application now pending before us . . . we have endeavored . . . to expedite the resolution of the permanent increase request and to minimize regulatory lag . . . . The claimed deficiency of PEPCO's return on D.C. rate base, short of circumstances constituting an emergency, is a central issue in the permanent rate case, as it usually is in all such proceedings. [Order 7038 in Formal Case 715 (Sept. 21, 1979).]

[12] This zone is bounded on the one side by the interests of utility customers in not paying exorbitant rates. *See* *Washington Gas Light Co. v. Baker, supra at 119, 188 F.2d at 15*. On the other side are the interests of utility investors in achieving a rate of return sufficient to maintain the utility's financial integrity, to permit the utility to attract necessary capital at a reasonable cost, and fairly to compensate themselves for the risks they have assumed. *Federal Power Commission v. Hope Natural Gas Co., supra at 603*; *In re Permian Basin Area Rate Cases, supra at 791-92*.

focus on whether **[**27]** the level of rates which remained in effect during the period in question, due to the Commission's denial of emergency relief, are below the reasonable range; whether the actual rate of return earned by PEPCO is so low as to deprive PEPCO of the opportunity to maintain its financial integrity, to attract necessary capital and to compensate investors fairly.

The record in this case adequately supports the PSC conclusion that **[**28]** the actual rate of return is not this low. [13] For instance, the Company was able to raise necessary capital. In August 1979, PEPCO completed the refinancing of its intermediate term pollution control debt (Supp. Rec. at 17) and sold $35 million worth of new preferred stock (Supp. Rec. at 202, 405). PEPCO's fixed charge coverage on outstanding debt -- the ratio of earnings available for interest and property retirement -- was 2.86 for the twelve months ending April 30, 1979, and was 2.92 for the period ending June 30, 1979 (Supp. Rec. at 201). Both of these figures were above PEPCO's indenture requirements, insuring the marketability of future debt issues. Moreover, investors were being fairly compensated. During the period in question, the utility continued to pay dividends to its preferred and common stockholders (Supp. Rec. at 345). PEPCO's actual earnings for the twelve month period ending April 1979, were above the Company's common stock dividend rate (Supp. Rec. at 15, 20). Finally, the Company was able to maintain its financial integrity. PEPCO's bond coverage continued to be in excess of required coverage (Supp. Rec. at 207). There was no immediate threat to the high **[**29]** ratings enjoyed by PEPCO bonds and senior securities. The record fails to contain any indication that PEPCO was unable to cover its present operating expenses or that it would have any difficulty in providing adequate electricity to its customers during the remaining hot summer months should their emergency application be denied. In other words, considered as a whole, there is substantial evidence to support the Commission's finding that the actual rate of return earned by PEPCO was not so low as to either threaten the Company with financial disarray or to effect a confiscation of property during the period before a new permanent rate increase could be approved.

V. DISMISSAL OF PEPCO'S SECOND APPLICATION FOR EMERGENCY RELIEF WITHOUT A HEARING

PEPCO's first application for emergency rate relief was the subject of a Commission hearing on July 23, **[**30]** 1979. At that hearing, PEPCO President and Chairman of the Board, W. Reid Thompson, and PEPCO General Vice President of Finance, H. Lowell Davis, testified in favor of PEPCO's application. Thereafter, the Commission granted intervenors' motions to dismiss. When PEPCO failed to demonstrate to the Commission's satisfaction that its second application for emergency rate relief involved any factual or legal grounds neither similarly relied upon in its first application nor considered in the hearing, the Commission dismissed the second application without a hearing. PEPCO challenges this dismissal as a violation of its due process rights.

[*789] If PEPCO's second application relied on the same facts and legal contentions considered by the Commission in dismissing the first application, *HN7*[] the Commission has the power to dismiss it without a hearing. A hearing is not necessary where no material facts are in dispute or where the disposition of claims turn not on the determination of facts, but inferences and legal conclusions to be derived from facts already established. *Citizens for Allegan County Inc. v. Federal Power Commission, 134 U.S.App.D.C. 229, 232, 414 F.2d 1125, 1128 **[**31]** (1969)*; *Anti-Defamation League of B'nai B'rith v. Federal Communications Commission, 131 U.S.App.D.C. 146, 403 F.2d 169 (1968)*, *cert. denied*, *394 U.S. 930, 22 L. Ed. 2d 459, 89 S. Ct. 1190 (1969)*. Having sustained the Commission's decision that PEPCO's first application failed to establish a *prima facie* case for emergency relief, absent additional or supervening facts, the Commission can enforce repose by invoking the doctrine of preclusion by judgment against PEPCO. Subsequent applications involving the same facts and issues existing at the time of the first Commission decision and actually considered by the Commission, need not be re-litigated. *See Stuckey v. Weinberger, 488 F.2d 904, 911-12 (9th Cir. 1973)* (applying res judicata to bar hearings on subsequent applications for disability benefits before the Secretary of Health, Education, and Welfare). Indeed, PEPCO's challenge to the Commission's dismissal of its second application without a hearing is somewhat ironic since another hearing on the same facts and issues existing at the time of the first application would only further delay disposition of the utility's permanent rate case. This delay, in turn, would **[**32]** increase the utility's revenue loss pending disposition of its permanent rate case.

We have reviewed both of PEPCO's applications for

[13] The record referred to in the text is that pertaining to the second application for emergency rate relief, and to supplemental filings to the first application.

emergency relief as well as the hearing held pursuant to the first application. We have also reviewed PEPCO's statement, submitted in response to the Commission's request, outlining the factual and legal grounds relied upon in its second application that were not similarly relied upon in its first application. We can find nothing in PEPCO's second application which indicates that its financial situation had changed since the denial of its first application. Nor does the second application present any additional facts evidencing an emergency that, due to oversight, were not presented in the initial application. In fact, the two applications present almost identical issues for the Commission's review. Therefore, there was no requirement for the Commission to repeat its earlier hearing.

Affirmed.

Dissent by: NEBEKER

Dissent

NEBEKER, Associate Judge, dissenting:

Once again it appears that the majority's resolution of this petition of appeal sanctions the proposition that "the Commission will conclude that virtually any treatment of a utility which purports **[**33]** to be 'pro-consumer' in nature is likely to escape perceptive judicial review." *Potomac Electric Power Co. v. Public Service Comm'n, 402 A.2d 14, 27 (D.C. 1979)* (Harris, J., dissenting). This "hear no evil, see no evil" approach to appellate review continues to evidence an alarming lethargy. The Commission's obligation is not merely the protection of consumer interests, but rather requires a *balancing* of investor and consumer interests, *Potomac Electric Power Co. v. Public Service Comm'n, 380 A.2d 126, 132 (D.C. 1977)*, and its actions must be considered in this light. The Commission is charged with the duty of insuring the prolonged economic health of the utility, one aspect of which entails the overall responsibility to insure that the utility be given the opportunity to earn a fair rate of return. *Id. at 131-32*. *See* *Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603, 88 L. Ed. 333, 64 S. Ct. 281 (1944)*; *McCardle v. Indianapolis Water Co., 272 U.S. 400, 408-09, 71 L. Ed. 316, 47 S. Ct. 144 (1926)*; *Bluefield Water Works & Improvement Co. v. Public Service Comm'n, **[*790]** 262 U.S. 679, 690, 67 L. Ed. 1176, 43 S. Ct. 675 (1923)*. As **[**34]** narrow as our jurisdictional stance may be, as a court sitting in review of a rate order allegedly unjust and unreasonable in its total effect, we must "delve into the details of the order" and "give reasoned consideration to each contested element of the rate order 'to determine the possible presence of arbitrary action.'" *Potomac Electric Power Co. v. Public Service Comm'n, supra, 380 A.2d at 132*. This the majority failed to do.

Initially, PEPCO is faulted by the Commission and this court for failing to direct its application for interim rate relief to anything other than its experience of earnings substantially less than that which is reasonable. Specifically, PEPCO allegedly erred by not demonstrating either "a present or clearly imminent threat that the Company will be unable to continue meeting its public service obligation" or "a present or clearly imminent threat that the Company will be unable to obtain necessary capital funds to finance the construction of necessary new or replacement plants." In fact, the Commission was presented with evidence of both of these factors relating to the "D.C. PEPCO" operations. While there is no such entity as "D.C. PEPCO" in a concrete **[**35]** sense -- PEPCO's operations extending into Maryland and Virginia -- for purposes of ratemaking proceedings, PEPCO's operations in other jurisdictions must be ignored. *Capital Transit Co. v. Public Utilities Comm'n, 93 U.S. App. D.C. 194, 213 F.2d 176, 182 (D.C. Cir. 1954)*. It is not axiomatic that because the Company as a whole is capable of obtaining necessary capital funds and meeting its public service obligations that "D.C. PEPCO" is sound. The record evidence relied upon by the majority to illustrate PEPCO's financial stability reflects PEPCO's operations *systemwide*. The results, therefore, are skewed against the Company's position presented in its interim request as the Company's Maryland and Virginia operations were on sounder financial ground. A decision by the Commission based upon these figures is both arbitrary and capricious and cannot be upheld.

Secondly, the majority cavalierly characterizes PEPCO's position as being a "make whole" request by declaring that "it is not the purpose of emergency rate relief . . . simply to close the gap between a return previously authorized and actual earnings. Rather, the purpose of emergency relief is to alleviate financial **[**36]** problems whose correction cannot safely await a decision on the proper level of permanent rates." This approach ignores PEPCO's contention that, rather than attempting to secure a *guaranteed* rate of return, it merely seeks the *opportunity* to realize the authorized rate of return. The Commission was presented both with figures and testimony to the effect that even if the interim relief were granted in full immediately, PEPCO's anticipated return would be but 7.96 percent for the year 1979. Given that the Commission authorized a 9.03 percent rate of return but days earlier, PEPCO's interim request cannot justifiably be characterized as "make whole."

Finally, the Commission took the position that it was inappropriate to use the previously authorized rate of return as the presumptively reasonable rate of return for the interim rate increase request. Given the posture of this case, such a position is untenable. Formal Case No. 685, a permanent rate increase case which had been pending for over a year and a half, resulted in a determination that a 9.03 percent rate of return was just and reasonable. The proposed order in Formal Case No. 685 was but a week old at the time of **[**37]** PEPCO's initial interim rate request. To fail to give any weight to the result reached in Formal Case No. 685 with regard to a reasonable rate of return defies rational explanation. *See* Formal Case No. 610, *In Re Washington Gas Light Co.*, Order No. 5655, at 9, July 11, 1974. The proceedings relating to interim relief requests should not so parallel permanent rate increase procedures that the harm **[*791]** befalling the utility exacerbates unnecessarily pending the outcome. This is especially true given the realities of the day -- rampant inflation, regulatory lag, attrition -- which affect the utility's ability to maintain sound financial footing. Absent some reason to the contrary, the Commission should have acknowledged the newly set rate of return as a valid benchmark for the determination of a just and reasonable rate.

I respectfully dissent.

End of Document

1990 Minn. PUC LEXIS 199; 115 P.U.R.4th 308

Minnesota Public Utilities Commission

August 28, 1990

DOCKET NO. E-002/GR-89-865

MN Public Utilities Commission ***Decisions***

Reporter
1990 Minn. PUC LEXIS 199 *; 115 P.U.R.4th 308

In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota

Core Terms

forecast, budget, was, rate case, cost, rate base, has, second year, capital expenditures, operating expenses, reliable, rate increase, intervenor, actual expenses, rebuttal, reasonable rate, first year, recommend, months, audit, many, star, accuracy, electric, fiscal year, deviate, expenditure, calculate, northern, defer

Panel: Darrel L. Peterson, Chair; Cynthia A. Kitlinski, Commissioner; Norma McKanna, Commissioner; Robert J. O'Keefe, Commissioner; Patrice Vick, Commissioner

Opinion

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

PROCEDURAL HISTORY

I. INITIAL PROCEEDINGS

On November 2, 1989, Northern States Power Company (NSP or the Company) filed a petition seeking a general rate increase of $ 120,782,000, or 10.2%, effective January 1, 1990. On November 13, 1989 the Company made a supplementary filing containing information inadvertently omitted from its initial filing.

On November 29, 1989, the Commission accepted the filing, suspended the proposed rates, and ordered contested case proceedings under *Minn. Stat. § 216B.16*, subd. 1 (1988). The Office of Administrative Hearings assigned Administrative Law Judge Richard C. Luis to the case.

On December 29, 1989, the Commission set interim rates under *Minn. Stat. § 216B.16*, subd. 3 (1988). Interim rates were authorized as of January 1, 1990 and were set at a level allowing an additional $ 81,542,000 in annual revenues.

The Administrative Law Judge (ALJ) held a Prehearing **[*2]** Conference on December 21, 1989. There the parties and the ALJ identified the major issues, established procedural guidelines, and set timetables.

II. PARTIES AND REPRESENTATIVES

A. Intervenors

The following parties filed petitions to intervene in the case. The ALJ granted all petitions.

Minnesota Department of Public Service, represented by Joan C. Peterson, Mary Jo Murray, and Eric F. Swanson, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota, St. Paul, Minnesota 55101.

Residential Utilities Division of the Office of the Attorney General, represented by Gary Cunningham, Dennis Ahlers, and Julia Anderson, Special Assistant Attorneys General, 340 Bremer Tower, Seventh Place and Minnesota, St. Paul, Minnesota 55101.

Minnesota Energy Consumers, represented by Byron E. Starns and James J. Bertrand, Leonard, Street and Deinard, Suite 2300, 150 South Fifth Street, Minneapolis, Minnesota 55402.

Champion International Corporation, represented by Peggy Wells Dobbins, 915 Aduana Avenue, Coral Gables, Florida 33146.

Union Carbide Corporation, represented by Maurice A. Frater, P.O. Box 1166, Harrisburg, Pennsylvania 17108.

Metalcasters of Minnesota, **[*3]** represented by John A. Knapp and Lloyd W. Grooms, Winthrop and Weinstine, 3200 Minnesota World Trade Center, 30 East Seventh Street, St. Paul, Minnesota 55101.

North Star Steel Company, represented by Garrett A. Stone, Ritts, Brickfield and Kaufman, Watergate 600 Building, Suite 915, Washington, D.C. 20037-2474.

Suburban Rate Authority, represented by Glenn E. Purdue, Messerli and Kramer, 1500 Northland Plaza Building, 3800 West 80th Street, Minneapolis, Minnesota 55431-4409.

City of St. Paul, Board of Water Commissioners of the City of St. Paul, and the Municipal Pumpers Association, represented by Thomas J. Weyandt, Assistant City Attorney, 647 City Hall, St. Paul, Minnesota 55102.

Minnesota Senior Federation, represented by Elmer Scott and Kenneth Zapp, 1855 University Avenue West, St. Paul, Minnesota 55104.

North American Water Office, represented by George M. Crocker and Bruce Drew, 3394 Lake Elmo Avenue North, Lake Elmo, Minnesota 55042.

St. Paul Chamber of Commerce, represented by William G. Flynn and David Sasseville, Lindquist and Vennum, 4200 IDS Center, 80 South 8th Street, Minneapolis, Minnesota 55402.

Minnesota Retail Merchants Association, represented by Corey **[*4]** Ayling, O'Connor and Hannan, 3800 IDS Center, 80 South 8th Street, Minneapolis, Minnesota 55402.

Minnegasco, Inc., represented by Miggie E. Cramblitt, Corporate Secretary, Minnegasco, 201 South 7th Street, Minneapolis, Minnesota 55402.

District Energy of St. Paul, Inc., represented by William M. Mahlum and Christine Stalker, 2222 North Central Life Tower, 445 Minnesota Street, St. Paul, Minnesota 55101.

The Minnesota Public Interest Research Group (MPIRG) also filed a petition to intervene, which was granted. However, MPIRG did not appear at the evidentiary hearings, did not sponsor any witnesses, did not file briefs, and did not otherwise participate in the case.

B. The Company

The Company was represented by David A. Lawrence and Michael Hanson, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401 and Samuel L. Hanson, Briggs and Morgan, 2400 IDS Center, Minneapolis, Minnesota 55402.

C. Withdrawal of Parties

Minnegasco and District Energy of St. Paul withdrew as parties when the Company withdrew its "Competitive Service Rider" rate proposal, the source of their interest in the case. All three parties agreed that competitive rates legislation enacted **[*5]** after the Company's filing made it unnecessary to include the proposal in the rate case.

III. PUBLIC HEARINGS

The ALJ held public hearings to receive comments and questions from non-intervening ratepayers. The dates and locations of these hearings are listed below, followed by the number of persons who attended each hearing. In all, 46 members of the public spoke.

March 6, 1990	Dilworth	17
March 7, 1990	St. Cloud	28
March 12, 1990	Coon Rapids	26
March 13, 1990	St. Paul	43
March 14, 1990	Minneapolis	44
March 20, 1990	Winona	23
March 21, 1990	Mankato	60

At least one Commissioner attended every public hearing, except the one at St. Cloud, where inclement weather prevented it. At least one member of the Commission's staff attended every hearing. Company representatives attended every hearing. Representatives of the Department of Public Service, the Residential Utilities Division of the Office of the Attorney General, the Minnesota Senior Federation, and North Star Steel Company attended various public hearings.

The public was also encouraged to submit written comments on the proposed rate increase; some 67 members of the public wrote to the ALJ or to the Commission. The **[*6]** Commission received telephone comments from 33 members of the public. Five members of the public called the ALJ.

IV. PRE-HEARING MOTIONS

A. Motion to Exclude or to Consider Filing Date as February 5, 1990

On February 12, 1990, the Residential Utilities Division of the Office of the Attorney General (RUD-OAG) filed a motion to exclude supplemental testimony filed by the Company on February 5, 1990. That testimony related to proposed ratemaking treatment of Tax Benefit Transfers which, if adopted, would increase the Company's claimed revenue deficiency by approximately 14 million dollars.

The RUD-OAG asserted this testimony should have been included in the Company's direct case and that its late filing denied other parties adequate opportunity to analyze and respond to it. The RUD-OAG also claimed that the information in the supplemental filing was so significant that the initial filing was incomplete without it, and that the ALJ should therefore find that the Company had not made a complete rate case filing until February 5, 1990, the date of the supplemental filing. In the alternative, the RUD-OAG requested that the filing deadlines for intervenor direct testimony and responses **[*7]** to the supplemental filing be extended.

The ALJ found that the supplemental filing was not an updating of previously filed forecasted information, as supplemental filings were required to be under the pre-hearing Order. However, he also found the filing did not fundamentally change the Company's original filing, did provide useful and relevant information, and should be considered in this case. He declined to exclude the testimony, declined to adjust the rate case filing date to

February 5, 1990, but did extend the filing deadlines for intervenor direct testimony and intervenor responses to the February 5 supplemental filing.

B. Joint Motion to Dismiss

On April 4, 1990, prior to commencement of evidentiary hearings, the Department of Public Service (the Department) and the Residential Utilities Division of the Office of the Attorney General (RUD-OAG) filed a joint motion to dismiss the Company's general rate case filing and requested that the motion be certified to the Commission. North Star Steel Company (North Star) and the Minnesota Energy Consumers (MEC) joined in the motion.

The motion to dismiss was based on the assertion that the Company's rebuttal testimony, filed March **[*8]** 27, 1990, contained so many additions and corrections to the initial filing that what remained of the initial filing was inadequate for purposes of setting just and reasonable rates. The moving parties also asserted that the rebuttal filing contradicted the initial filing in so many crucial respects that the rebuttal filing itself demonstrated the inappropriateness of any attempt to set just and reasonable rates on the basis of the initial filing. They further argued that the substance and scope of the rebuttal filing were so far-reaching that it actually constituted a new rate case filing, requiring dismissal of the initial filing and the ongoing rate case.

The ALJ denied the joint motion to dismiss and declined to certify the motion to the Commission.

C. Joint Motion to Exclude

In conjunction with their joint motion to dismiss, the Department and the RUD-OAG moved that the ALJ exclude large portions of the Company's rebuttal testimony, on grounds that it constituted new material or was offered by unqualified witnesses. They also sought exclusion of certain portions of the Company's original testimony, on grounds that it had been discredited by the rebuttal filing or was offered **[*9]** by unqualified witnesses. North Star and MEC joined in this motion also.

The ALJ granted this motion in part and denied it in part. Small portions of the Company's rebuttal testimony were stricken as being in substance direct testimony. The majority of the testimony at issue remained in the record.

The Department then moved to strike all remaining testimony of Ronald Clough, some of which was excluded by the partial granting of the joint motion to exclude. This motion was denied.

D. Motions to Compel Discovery

North Star Steel Company (North Star) and NSP brought motions against one another to compel discovery of significant amounts of financial information not in the record.

The ALJ denied NSP's motion as inappropriate and burdensome. The Company had admitted the reason for its motion was in part "to turn around on North Star the "discovery assault" North Star perpetrated upon it." The ALJ noted that it was NSP's financial operations which were at issue in this proceeding, not those of the intervenors. He concluded the information NSP sought in regard to North Star's financial and accounting practices was irrelevant.

The ALJ also denied North Star's motion, finding the Company **[*10]** had honored many of the discovery requests at issue before the motion was heard, and that the remaining requests were unreasonably burdensome.

E. Motions Renewed

In ruling on the joint motion to dismiss, the ALJ stated that he would continue taking the motion under advisement throughout the course of the proceeding. The Department and North Star renewed the motion in their post-hearing briefs.

On briefing the Department also renewed its motion to exclude and its motion to strike all testimony of NSP witness Ronald Clough not excluded by the partial granting of its motion to exclude. North Star similarly renewed its motion to compel discovery. All motions were again denied in the ALJ's report and recommendation to the Commission.

V. EVIDENTIARY HEARINGS

The ALJ held evidentiary hearings in St. Paul from April 9-13, April 16-20, and April 23-26, 1990. He closed the record on July 2, 1990.

VI. PROCEEDINGS BEFORE THE COMMISSION

The ALJ filed his report and recommendations in two parts. The first part, dealing with revenue requirements, was filed on July 13, 1990. The second part, dealing with conservation and rate design, was filed on July 19, 1990. He also filed Additional Findings **[*11]** of Fact and Conclusions on revenue requirements on July 17, 1990.

The Commission established ten-day time periods for filing exceptions to Parts I and II of the ALJ's report by Orders dated July 13 and July 19, 1990.

The Commission heard oral argument on July 30 and 31, 1990. At the end of oral argument the Commission Chair announced that deliberations would begin with an opportunity for Commissioners to ask any final questions they might have. On August 2 deliberations opened with the Chair asking the Company to further explain its reasons for considering its filed test year data reliable and accurate. All parties were allowed to comment on the Company's answer.

Upon review of the entire record of this proceeding, the Commission makes the following Findings, Conclusions, and Order.

FINDINGS AND CONCLUSIONS

VII. JURISDICTION

The Commission has general jurisdiction over the Company under *Minn. Stat. § 216B.01* and .02 (1988). The Commission has specific jurisdiction over rate changes under *Minn. Stat. § 216B.16* (1988).

This case was properly referred to the Office of Administrative Hearings **[*12]** under *Minn. Stat. §§ 14.57*- 14.62 (1988) and Minn. Rules, part 1400.0200 et seq.

VIII. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, part 7830.4100 any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of this Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under *Minn. Stat. § 216B.27*, subd. 3 (1988), no Order of the Commission shall become effective while a petition for rehearing is pending **[*13]** or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. *Minn. Stat. § 216B.27*, subd 4 (1988).

IX. NORTHERN STATES POWER COMPANY

NSP is an investor-owned gas and electric utility incorporated in the state of Minnesota. It provides electric service in Minnesota to approximately 1,009,442 retail customers, approximately 877,465 of them residential. Its service area covers approximately 40,000 square miles and includes parts of Minnesota, Michigan, Wisconsin, North Dakota, and South Dakota.

The Company's Minnesota service area is comprised roughly of the southern one-third of the state, and includes the Minneapolis-St. Paul metropolitan area. Most of the Company's electric revenues come from service to the metropolitan area.

This rate case involves only the Company's electric operations in the state of Minnesota.

X. SUMMARY OF PUBLIC TESTIMONY

Two hundred forty-one people attended the public hearings in this **[*14]** case, and 67 submitted written comments. Thirty-three members of the public contacted the Commission by telephone to comment on the proposed rate increase. Public testimony and comment were offered on a variety of issues.

Several community organizations in the Company's service area took a position on the proposed rate increase. Minnesota ACORN (Association of Community Organizations for Reform Now) opposed the increase, submitting a petition signed by 229 ACORN supporters. They emphasized the hardships rate increases impose on low income and fixed income ratepayers. They particularly opposed the reduction in the Conservation Rate Break proposed by the Company.

The Senior Federations in Winona and Mankato also opposed the rate increase. In Winona the Federation presented a petition, signed by 58 Dodge County residents, urging its rejection. The NSP Retirees Club of Local 160, International Brotherhood of Electrical Workers, similarly opposed the increase. The Retirees Club advocated close examination of executive compensation and pension levels, lobbying expenses, consultant hiring practices, and the environmental implications of the Company's water resource practices and PCB-burning **[*15]** project.

The International Brotherhood of Electrical Workers, Local 160, representing active union members, supported the increase. They also asserted the Company and the union had formed a partnership to cut costs and save energy.

Local chambers of commerce and community economic development agencies appeared at hearings in St. Cloud, Minneapolis, Winona, and Mankato. They praised the Company's corporate citizenship and economic development efforts, particularly in the area of business retention. The Deputy Commissioner of the Minnesota Department of Trade and Economic Development appeared at the St. Paul hearing and offered similar testimony.

Officials from two major businesses in Mankato testified that NSP has fair rates and helpful, courteous employees.

Most of the members of the public who wrote to the Commission or to the ALJ opposed the requested rate increase. Many argued that the Company should not need another general rate increase so soon after its last one. Many urged careful scrutiny of the proposed increase, emphasizing that electricity is an essential service provided under monopoly conditions. Many people stated that their incomes were not rising as rapidly as **[*16]** their utility bills.

XI. SUMMARY OF COMMISSION ACTION

Because of grave doubts about the accuracy, reliability, and predictive value of the test year budget data submitted by the Company, the Commission will deny the requested rate increase. The Commission finds that the rate case record does not demonstrate that existing rates are unjust and unreasonable, which is necessary for approval of a general rate increase. Neither does the record provide a reliable basis for setting new just and reasonable rates.

Existing rates, which were just and reasonable when set and are presumed just and reasonable until proven otherwise, shall remain in effect. *Minn. Stat. § 216B.16*, subds. 4 and 5 (1988). The inadequacies of the record are summarized below and explained in greater detail in the remainder of this Order.

NSP based its rate increase request on a fully forecasted 1990 test year. The Company did not base the test year forecast on actual 1989 financial results or on actual results from any other historical period. Instead, the Company based the test year forecast on management projections of what the financial needs of the Company would be during **[*17]** the 12-month test year period. This deprived the Commission of the opportunity to compare individual items in the forecast with corresponding items on the actual books. The Commission's only recourse, then, was to evaluate the accuracy and credibility of the overall budgeting process.

This evaluation disclosed serious deficiencies. First, historical analysis of the two year budgeting process used by NSP revealed that second year capital budgets were consistently overestimated, and that the degree to which they were overestimated was steadily rising. The differences between second year capital budgets and actual capital expenditures for the past four years are as follows: 1986 - 4.39%, 1987 - 8.60%, 1988 - 24.33%, and 1989 - 28.27%. In all years projections exceeded actual expenditures. Since test year forecasts are for periods similar to second year budget periods, it would appear that test year capital expenditures are also overstated.

A Department audit of the Company's 1989 capital forecast produced results consistent with this pattern of overestimating capital expenditures. The Department examined a sample of 100 items from the 1989 capital forecast, which the Company used to **[*18]** develop test year rate base. The forecast for the 100 items in the sample exceeded actual expenditures on the items by 27.12%.

Similarly, the Department's audit of the 100-item sample found several items in the test year rate base which clearly did not belong, and others which were highly questionable. Those items included reimbursable projects, non-electric utility projects , projects not yet begun but included in rate base, projects not yet in service but included in rate base, cancelled projects, and non-specific, unidentified project funds. The Company conceded that many of these items should have been excluded from the capital budget and from rate base.

Finally, an examination of operating and maintenance expenditures over the past five years reveals a pattern of significantly higher spending in rate case years than in non-rate case years. For test year 1990 the Company expects to exceed its second year operating and maintenance budget by 7.8%, after underspending its 1989 budget by 2.67%. This strongly suggests that the Company has overestimated its operating and maintenance expenses for the test year, or that the test year operating and maintenance forecast is not representative **[*19]** of expenses in a non-rate case year.

The Commission concludes that the Company's filing does not provide a reliable foundation from which to determine just and reasonable rates.

XII. BACKGROUND INFORMATION

A. Historical Context

The $ 120,782,000 rate increase requested by the Company is the second largest rate request in Minnesota history, and the second largest ever filed by this Company. It was filed only 14 months after the Commission granted the Company a $ 75 million rate increase. Presumably, the $ 75 million increase met the Company's financial needs at the time, since the Company stipulated to that amount. In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in Minnesota, Docket No. E-002/GR-87-670. Over half of the increase was attributable to the addition of a new major generating facility, Sherco 3.

By contrast, the current rate request was not prompted by any major construction project or other significant addition to rate base. The fourteen month period between the last rate increase and this filing was a period of relatively stable prices, [1] substantial growth in Company electric revenues, **[*20]** continued protection from fuel and purchased power cost increases through the fuel adjustment clause, [2] and protection from changes in mandated conservation costs through the conservation tracker account. [3] In short, this was a rate case in which the factors which usually drive rate cases -- e.g., a new plant, a period of high inflation -- were missing. In the absence of other major issues, the Company's budgeting processes were carefully examined in an attempt to discover what was causing the need for a rate increase.

B. Overview of the Company's Budgeting and Forecasting System

The Company's budgeting process is complex. The record refers to first year budgets, second year budgets, **[*21]** first year forecasts, second year forecasts, test year forecasts, normalized actual data, and actual data. Actual data represents actual operating results for a historical period, while normalized actual represents actual operating results for a historical period, after adjustments to reflect normal operating conditions. An example of such an adjustment would be adjusting sales revenues to reflect average weather conditions.

NSP's budgeting process includes preparing and revising several budgets. Some examples include capital budget, departmental operating expense budgets, and sales budget.

In the fall of 1988, NSP created its budget for the next two years. The first year budget was for 1989 and the second year budget was for 1990. Then, on a monthly basis, NSP reviewed current information as it developed and created the first year forecast (1989) and second year forecast (1990). This activity continues on an ongoing basis whether or not a rate case is planned.

In approximately August of 1989, NSP forecasted the data for the 1990 test year and made regulatory adjustments resulting in the test year forecast. The test year forecast filed in the rate case contains the data upon which **[*22]** NSP asked the Commission to rely to set rates effective January 1, 1990.

XIII. THE COMPANY'S CAPITAL BUDGET

The issue confronting the Commission in regard to NSP's capital budget is whether it provides enough credible substantiating evidence to allow the Commission to determine rate base and establish just and reasonable rates.

In the original filing, NSP requested a rate base of $ 2,372,746,000. This compares to a rate base of $ 2,342,665,000 found in NSP's last rate case, NSP, Docket E-002/GR-87-670. Except for a Company proposal to consider tax benefit transfers of approximately $ 73,142,000 as a source of zero cost capital, rather than as a reduction to rate base as in the last rate case, the originally filed rate base would be lower than the one approved in the last rate case. This is indicative of a company that is not presently involved in major construction projects.

The $ 2,372,746,000 rate base amount is an average of the January 1, 1990 rate base and the December 31, 1990 rate base. In order to have beginning of year and end of year rate base amounts at the time it made the filing, it was necessary for NSP to project the January 1, 1990 balance and the December **[*23]** 31, 1990 balance. The January 1, 1990 balance was projected based on part-year 1989 actual data, plus forecasted capital expenditures for the remainder of 1989. The December 31, 1990 balance was projected based on forecasted expenditures expected to occur during 1990.

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[1] One estimate of the inflation rate was 4.6 percent as shown by NSP witness Currier on JAC-1 Schedule 6, Page 1 of 1.

[2] ***Minn. Stat. § 216B.16***, subd. 7 and Minn. Rules 7825.2390.

[3] Pages 21-23 of the Commission's Findings of Fact, Conclusions of Law, and Order in In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in Minnesota, Docket No. E-002/GR-87-670 (August 23, 1988).

The Department recommended that the Commission deny the Company's request for a rate increase on grounds that the information in the record did not support the request. In the alternative, the Department recommended that the test year rate base be reduced by at least $ 82,152,000 to reflect errors in the capital budget discovered during the Department's audit and investigation. This amount represents a 27.12 percent reduction in the 1989 forecasted capital expenditures and a 23.08 percent reduction in the 1990 forecasted capital expenditures. The Department also recommended an additional $ 3,736,000 reduction to remove reimbursable projects erroneously included in rate base.

The Department recognized that in order to determine the reasonableness of forecasted data, the data must be subjected to intense scrutiny. As a starting point, the Department conducted an overall analytical review. This review focused on the relative **[*24]** accuracy of second year budgets and first year budgets when compared to the actual data for the corresponding historical periods. This review showed that the second year capital budget exceeded actual capital expenditures by 4.39 percent in 1986, 8.60 percent in 1987, 24.33 percent in 1988, and 28.27 percent in 1989. [4] In addition, the review indicated that first year budgets are showing indications of greater deviation and volatility from actual expenditures. Thus, the first year budget for 1988 (prepared in 1987) exceeded actual capital expenditures for 1988 by 24.74 percent. 1988 was the test year in NSP's last rate case.

Although the second year budget normally exceeded NSP's actual capital expenditures, NSP's forecast for the 1990 rate case test year exceeded the 1990 second year budget by approximately $ 46 million. Based on the trends identified above, the Department estimated that forecasted expenditures for the rate case test year would exceed actual expenditures by $ 115 million. [5]

A. The Department's Sample and Audit

In further investigation, **[*25]** the Department employed a discovery sample to review the forecasted capital expenditures for 1989, which the Company used to calculate beginning of test year rate base. NSP identified specific projects according to improvement requisitions (IRs). The Department identified approximately 4,000 IRs, then reduced that to 2,600 to eliminate those relating to other jurisdictions. The Department further reduced the number by limiting projects to those beginning and ending in 1989. Approximately 600 IRs remained, from which the Department ultimately took a sample of 100. The sample represented approximately $ 15 million of budgeted projects from approximately $ 233 million for the Minnesota Company, excluding gas operations.

The Department's examination of the sample found a difference of approximately $ 4.1 million, or 27.12 percent, [6] between amounts budgeted and amounts actually spent. For the items in the sample, at least, the Company clearly had over-budgeted for capital expenditures.

The sample also included several items which clearly did not belong in rate base under any circumstances. For example, it included a refuse derived fuel **[*26]** (RDF) trailer, a non-electric utility project. NSP agreed that that item should not have been in rate base.

The IRs in the sample included one project for which NSP will be reimbursed by another party. In follow-up, NSP located 26 other reimbursable projects and 14 blanket projects which included amounts for reimbursable projects. NSP agreed that reimbursable projects should not be in rate base.

The sample identified 10 projects which were scheduled to begin and end in 1989, but had zero expenditures in 1989. Since these are included in the forecasted beginning of the test year rate base, but no expenditures have been made, rate base is clearly overstated by the amounts budgeted for these projects.

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[4] DPS Exhibit 158, Page 11, Direct Testimony of Vincent C. Chavez.

[5] DPS Exhibit 188 at 6. Direct Testimony of Dale V. Lusti.

[6] DPS Exhibit 161, Vincent C. Chavez VCC-7.

The sample identified 32 projects with December 31, 1989 Plant in Service dates, which were not yet in service. Again, rate base may have been overstated by the amounts budgeted for these projects.

The sample identified a cancelled project. This project was included in the forecasted beginning of test year rate base, but will never be completed, again resulting in an overstated rate base. On follow-up, NSP identified 140 other cancelled projects, all included in test year rate base. **[*27]**

The sample identified project funds and corporate funds. These funds derive from cancelled projects and projects completed below budget. At year-end, NSP zeroes out these fund balances. The Department was concerned that funds already included in the forecast and in test year rate base could be zeroed out and diverted to non-utility or non-Minnesota operations. The Department indicated that the total draw-downs for the corporate fund in 1989 were over $ 58 million.

B. The 1990 Forecast

The Department was unable to sample NSP's 1990 capital expenditure forecast, used to develop end of test year rate base, because 1990 actual data was not in existence. Instead, the Department examined the 1989 second year budget, in which the Company over-forecasted by 28.27 percent above 1989 actual expenditures.

The Department recognized that the accuracy of NSP's forecasts improves as the period being forecasted gets closer. Since the rate case 1990 test year forecast was constructed using several months of actual 1989 data, the Department constructed a mathematical model [7] to incorporate assumed improved accuracy. As a result, the Department recommended that the forecasted capital expenditures **[*28]** during the 1990 test year be reduced by 23.08 percent.

C. Commission Conclusions

When determining just and reasonable rates, the Commission is directed by *Minn. Stat. § 216B.16*, subd. 6 (1988) to give due consideration to property used and useful in utility service. Such property must also be prudently acquired. In order to meet that statutory directive, the Commission must be able to determine the proper amount to include in rate base for the test year.

The Department's investigation raises grave doubts about the Company's forecasted 1990 test year rate base and the methods used to derive that rate base. As noted above, the historical trends point to increasing inaccuracy and unreliability in NSP's first and second year budgets used to forecast future capital budgets. The sample conducted by the DPS has revealed many individual and specific errors, which the Company has the burden of explaining.

1. The Company's Position

a. Past Practice

NSP indicated that it has based its plant and CWIP amounts on capital expenditure forecasts since its first rate case in 1975. **[*29]** The Commission does not dispute that it has accepted, and will continue to accept, forecasted test year data. However, the Commission has noted its discomfort with inadequately documented forecasted test years in the past, including the last fully litigated rate case brought by this Company. NSP, Docket No. E-002/GR-85-558, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, at 8 (June 2, 1986). Further, the Commission will not simply accept forecasted data without review because it has accepted such data in the past. Each case will be reviewed according to its own merits. In this case, serious questions concerning the capital expenditures have been raised which cast serious doubt over the reasonableness of the rate base proposed by NSP.

b. The Significance of Actual Data and Specific Projects

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[7] DPS Exhibit 160, Vincent C. Chavez Surrebuttal, VCC-82 Corrected.

The Company argued that the updated "actuals" for 1989 show that its projections for 1989 are accurate and reliable. The Commission agrees with the Department and other parties that the use of unaudited actuals filed 13 days prior to the hearing does not bolster the forecast in this case. NSP's reliance on 1989 actual data to support its 1989 forecast ignores the purposes for which 1989 data **[*30]** are offered, namely to test the accuracy and reliability of its forecasting method. NSP did not submit any evidence of its forecasting method to which the 1989 data could have been applied. The Commission does not find that the data supplied by NSP in rebuttal are probative of the issue in the case.

NSP argued that the Department's sample failed to accurately predict what the actual capital expenditures for 1989 would be. The Commission notes that the sample was conducted to determine how well NSP budgets capital expenditures, not to determine what the actual 1989 expenditures would be. The record shows that many projects that were forecasted were later cancelled or otherwise adjusted.

The Company argued that the Department did not identify specific forecasted capital expenditures as unnecessary or unreasonable . The Commission notes that the sample was designed to determine how well NSP predicts capital expenditures, not how reasonable each project is. A determination on the reasonableness of individual projects would be based on a review of a list of projects. A determination on whether or not projects which are charged to ratepayers are actually carried out would be based on **[*31]** a comparison between forecasted amounts and actual expenditures.

c. The Appropriateness of the Sample

NSP argued that the discovery sample was not representative of the total population of IRs. The Commission recognizes that the Department made many adjustments in arriving at the subpopulation and has not demonstrated that the sample is totally representative of the entire population of IRs. However, the sample did focus on projects beginning and ending within 1989 and revealed many errors. Furthermore, the sample included three projects, all with individual budgets in excess of $ 1 million , which were over-budgeted by as much as 51 percent. The magnitude of such budgeting errors raises concerns which cannot be allayed by attacks on the Department's methodological rigor. Whatever the margin of error inherent in the Department's sampling technique, the Department's investigation demonstrates that there are serious inadequacies in the Company's capital budgeting process. Those inadequacies infect the test year rate base and make it unreliable for purposes of setting just and reasonable rates.

The Company argued that the Department could have reviewed the 4,000 IRs or at a minimum, **[*32]** the 2,600 IRs associated with the Minnesota Company. The Commission notes that the Company could have chosen to rebut the sample by supplying complete information on all the IRs. The Company controls that information and is in the best position to offer such evidence. Instead, the Company chose to argue that the sample was inappropriate, leaving the doubts raised by the sample unresolved. The Company did not meet its burden of proof and show, by a preponderance of the evidence , that its capital budget is reliable and trustworthy. The Commission finds it more likely than not that the kinds of errors which affect the sample affect the Company's entire capital budget.

The Company argued that there was no need to sample, because the actual results for 1989 were known. The Company contends that, based on 1989 actual results, the Minnesota Company forecast was only overstated by 0.55 percent, not the 27.12 percent the sample suggests. Again, however, rather than address the results related to the specific 4,000 IRs upon which the test year capital forecast was based, the Company chose to rebut by filing additional unaudited information relating to aggregate expenditures. The Company **[*33]** filed 600 pages of testimony and exhibits, including unaudited updated data to replace the seven months of projected data the Company had used to calculate its January 1, 1990 rate base. Since the Company did not address the specific 4,000 IRs upon which the test year capital forecast was based, the filing did not disclose the extent to which the expenditures made were the expenditures projected.

The Commission is asked to establish a test year rate base which was calculated using a forecast. Yet when numerous errors and changes are found in the forecast, the Commission is asked to accept unaudited 1989 data, which at most establishes only that the money was spent. The filed data does not identify the purposes for which it was spent, or even confirm that it was spent for regulated Minnesota electric utility operations.

d. Significance of Cancelled Projects

The Company argued that there is no adverse impact on ratepayers if an item included in the rate case forecast is cancelled and channeled through the contingency fund to a non-utility project as long as the expenditures were not included in test year actual expenditures. The Commission finds this argument confusing at best. If **[*34]** a rate case forecasted item is cancelled and the funds are reallocated to a non-utility project, ratepayers have funded a project that is not used and useful in providing utility service.

Apparently NSP argues that as long as the project is replaced with another utility project, ratepayers will not be adversely affected. However, this lack of specificity is exactly the Commission's concern. It does not allow the Commission to fulfill its statutory duty to ensure that rate base includes only property used and useful in providing service to the public. *Minn. Stat. § 216B.16*, subd. 6 (1988). The Company's approach provides no certainty on what the rate base will include. All that is known is that rate base is likely to not include many of the projects the forecast said it would include.

NSP argued that the Department's recommended adjustment of 23.08 percent to the 1990 capital expenditures forecast should have been based on a project by project evaluation, including determinations on the reasonableness of individual projects. The Commission notes that the Department's adjustment is based on a historical deviation between second year budgets **[*35]** and actual capital expenditures for 1989. That deviation was shown above as 28.27 percent, adjusted to 23.08 percent to allow for improvement with the passage of time. That adjustment does not address the reasonableness of individual projects, but does attempt to adjust the test year rate base to represent only those projects that will actually be carried out.

e. Reference Points for Budget Comparisons

The Company argued that the first year budget for 1990 would have been a more appropriate comparison for the test year capital expenditures forecast. There, NSP stated that the 1990 test year forecast exceeded the 1990 first year budget by approximately 6 percent. Further, the Company argued that it was inappropriate to compare to the 1990 second year budget since the test year forecast was not based on the second year budget, but on an independent forecast.

The Commission is also concerned about comparing the test year forecast to the second year budget in the aggregate. However, overall review demonstrates that second year budgets have recently exceeded actual results by a wide margin. The sample conducted on the 1989 capital forecast also showed a wide margin of deviation. First **[*36]** year budgets also show a recent trend to overbudget, with 1988's (another test year) first year budget exceeding actual results by nearly 25 percent. [8] The first year budget to test year forecast deviation of 6 percent tends to support the concern regarding forecasting error. Furthermore, comparisons to the 1990 first year budgets may be skewed, since NSP knows what the target is from the test year forecast. These facts raise serious doubts about the 1990 capital expenditures forecast as well.

The Company argued that the mathematical formula employed to reflect improved forecasting accuracy as the forecasted period gets closer was based on improper assumptions. The Company argued that the formula was skewed because the Department chose to base it on the year with the most extreme deviation (1989). The Commission assumes that the formula is not precise and that there is room to question the Department's choice of 1989 as the basis for measuring improved accuracy. This is a minor concern, however, and should not obscure the central fact that there is a disturbing gap between forecasted expenses **[*37]** and actual expenditures.

2. The ALJ's Recommendations

[8] NSP Exhibit 57, Stephen R. Foss, Rebuttal Testimony, Schedule 9, Page 1 of 1.

a. Comparisons with Actual Data

The ALJ suggested that the Department could have performed a comparison of aggregate forecasted expenditures with the actual 1989 results, as did NSP. However, as discussed above, this comparison determines only that the money was spent, not how it was spent. Only an itemization by the Company, with auditing, would have shown how it was spent, and the 13 days between the filing of the information and the opening of evidentiary hearings were insufficient time to conduct an audit.

The 1989 actuals do not address the more fundamental concern raised by the Department and other parties about the reliability of the August 1989 capital budget/ forecast for 1990. Nor do they address the underlying concern about the forecasting method. The 1989 actuals are only probative of the reliability and accuracy of projections made for 1989.

The fact that NSP's August 1989 forecast was borne out by actual results does not show that the August 1989 forecast for 1990 test year was reliable and accurate. It merely shows that NSP was able to stay within its budget target for the remainder of the year. The 1989 data **[*38]** also raised a set of its own questions, such as why spending in December 1989 exceeded budgeted spending for the first time in three years. Since the Company was planning to file a rate case, the fact that actual data met the forecast does not dispel the concern that the forecast and the data were manipulated and prepared in anticipation of NSP's decision to seek a rate increase. The Commission cannot discount the possibility that spending was motivated by the need to fulfill a rate case forecast, which the Company knew could not be audited within the time frames imposed by the rate case statute.

b. The Representative Character of the Sample

The ALJ found that there was enough doubt about the representative character of the Department's sample to conclude that the results of the audit could not be reliably applied to the total capital forecast. The Commission disagrees. NSP submitted no information on the total population to show that the sample was seriously unrepresentative. NSP chose instead to rebut by showing that the Company actually spent the entire amount it had forecasted for 1989. Given the serious discrepancies disclosed in the sample audit, however, this is not reassuring. **[*39]** Without detailed explanations of individual budget items, the Commission has no verification that these monies were spent on projects used and useful in the Company's regulated Minnesota electric utility operations. The presence of unregulated, reimbursable, and cancelled projects in the sample, and in test year rate base, is not reassuring. Neither is the fact that the funds flow through the Corporate Fund for regulated and unregulated projects in all jurisdictions. Furthermore, the Company clearly had an incentive to spend all amounts forecasted for 1989, knowing failure to do so would raise questions about its need for the requested rate increase. For these reasons, the fact that the 1989 forecast was spent in full does not discredit the results of the Department's audit.

The ALJ gave a great deal of weight to the testimony of NSP witness Campbell, who stated the statistical probability that the sample is comparable to the total population is so remote as to be meaningless. The Commission finds this cause for concern. At the same time, however, the errors the sample disclosed in the capital forecast are real. Furthermore, when the Company examined the 1989 capital forecast in **[*40]** light of the sample's findings, more of the same errors appeared. For example, reimbursable projects, unregulated projects, and cancelled projects were found in the 1989 capital forecast, in significant numbers. The Commission does not find that the Department's audit, and the sample on which it was based, directly reflect the number of errors in the Company's 1989 capital forecast. The Commission does find, however, that the audit demonstrates the presence of serious inadequacies in the capital budgeting process which make the test year capital forecast unreliable for purposes of setting just and reasonable rates.

c. The Sample's Exclusion of Multi-year Projects

The ALJ stated that the exclusion of multi-year projects from the Department's sample tends to bias the results. There are no comparisons of such budgets in the record, however, to show that budgets for multi-year projects are more accurate than those for projects scheduled to be completed in a single year. It is not self-evident that such budgets would be more accurate. In fact, it can be argued that budgets for discrete projects lasting less than a year would be easier to project. Furthermore, the sample did include three **[*41]** projects with budgets in excess of $ 1 million each. Those projects also recorded large deviations. The Commission is therefore unconvinced that the exclusion of multi-year projects from the sample requires its rejection.

d. Witness Integrity

The ALJ stated one reason he declined to apply the results of the Department's audit to the Company's filing was that he did not find the traits of dishonesty or incompetence in NSP's witnesses. However, that is not the issue. The issue is whether the Company has proved by a preponderance of the evidence that its budgeting process is reliable and accurate enough to serve as the foundation for a Commission determination of just and reasonable rates. The Commission finds that the Company has failed to meet this burden.

The record shows that NSP's capital expenditure budgets are becoming increasingly inaccurate, with deviations between budgeted and actual expenditures approaching 30 percent. Not only do second year budgets suffer from such deviations, but first year budgets are also beginning to be affected. According to NSP witness Foss, Exhibit 57, Schedule 9, page 1 of 1, first year budgets overestimated capital expenditures only once from **[*42]** 1980 through 1987. However, in 1988 (a test year) the first year budget overestimated actual expenditures by nearly 25 percent. In 1989, the first year budget overestimated by nearly 9 percent. While such budgets may be sufficient for the purpose of day-to-day operations of the Company, the Commission cannot depend on such information when setting rates.

3. The Company's Need for Flexibility

The Commission recognizes that flexibility is necessary when operating the Company. It would not be wise or prudent to implement erroneous budgets. The Company needs the freedom to underspend its budget when projected spending proves to be unnecessary. Much less flexibility can be tolerated when forecasts and budgets are used as the foundation for rates. Once rates are set, ratepayers will not have the opportunity to make day-to-day adjustments to rates to reflect flexibility in operations. Rates must be based on data which reasonably represents the needs of the Company in providing service. To base rates on forecasts which may allow the Company flexibility of up to 30 percent does not result in just and reasonable rates. NSP cannot pass its budgeting and forecasting risks on to the ratepayers. **[*43]**

4. Substantiation Required

Minn. Stat. § 216B.16, subd. 1 (1988) provides that a change of rate notice shall include substantiating documents and exhibits. Those substantiating documents are to be included with the filing. With errors and deviations of the magnitude discovered in the forecasted material supplied, NSP has not met its burden of supplying adequate substantiating evidence with its notice of change in rates.

The Commission is not convinced that the Company has shown that its capital budget/ forecast and its forecasting method are accurate and reliable or that its 1990 forecast is evidence of a need for an increase in rates. NSP has not provided sufficient detail in regard to how it arrived at its 1990 forecast or how it determined that it needed an increase in rates.

The most straightforward attempt to secure information on this subject was made by North Star Steel. That intervenor served information requests intended to confirm or allay its suspicion that the 1990 forecast was designed to conform with rate case goals, instead of the rate case being designed to conform with an objectively prepared 1990 forecast. North Star was **[*44]** unsuccessful, however. The Company refused to reply, citing attorney-client privilege and attorney work product privilege, and the ALJ upheld the Company's objection.

5. The Intervenors' Proposed Adjustments

The Commission does not believe just and reasonable rates can be set by accepting or modifying the adjustments proposed by the intervenors. Historically, the Commission has adjusted proposed rate bases and operating budgets based on review of specific issues. Here, the adjustments proposed represent "across the board" adjustments based on a sample and historical trends. The Commission believes ratemaking requires more reliable facts and greater certainty than this record provides. The information in this record does not allow calculation of a rate base which is sufficiently verifiable and substantiated to cause the Commission to declare the rate base found in the last rate case unreasonable. Rates are not to be changed unless it is shown by a preponderance of the evidence that existing rates are unjust and unreasonable. *Minn. Stat. § 216B.16*, subd. 5 (1988). The Commission concludes that it cannot proceed with ratemaking on the basis **[*45]** of the existing record.

XIV. OPERATING AND MAINTENANCE EXPENSES

In its original filing NSP claimed test year total operating expenses of $ 1,195,737,000. This represents an increase of approximately 17% over the $ 1,023,766,000 stipulated to and allowed in the last rate case. In supplemental and rebuttal filings, the Company increased its estimate of necessary operating expenses to $ 1,199,777,000. Commission discussion will generally focus on the first number, as the intervenors did.

The Company also forecasted test year revenues of $ 1,358,824,000, an increase of approximately $ 85,000,000 over revenues authorized in the last rate case. The record reflects little disagreement with the forecasted test year revenues.

As discussed earlier in the order, NSP's rate case test year expense forecast is developed using its budgeting and forecasting systems. 1990 test year expenses were forecasted in approximately August of 1989, with the rate case filed on November 2, 1989. Parties have raised serious concerns regarding the forecasted expenses. Those concerns will be addressed below. Parties also raised concerns about several other individual expense items. Those issues are not discussed **[*46]** in this order.

A. Positions of the Intervenors and the ALJ

1. The Department

The Department recommended that operating expenses [9] be reduced by $ 23,293,000. The Department believed this adjustment was necessary to eliminate costs deferred into the test year from earlier periods, and to reflect historical deviations in NSP's budget.

The Company's 1990 test year DOE (departmental operating expense) forecast projected operating expenses 7.8 percent higher than the operating expenses projected in the second year budget for 1990, originally prepared in the fall of 1988. To put the matter in perspective, the Department studied the historical deviation of second year budgets to actual expenses over the years 1986-1989. This review indicated that actual expenses exceeded **[*47]** second year budget expenses by 2.4 percent in 1986, 3.64 percent in 1987, and 6.9 percent in 1988 (the test year in the last rate case) . However, in 1989, second year budget expenses exceeded actual expenses by 2.7 percent. Based on Department calculations, actual expenses exceeded the second year budget by an average of 2.5 percent for the years 1986-1989.

The Department recommended that test year operating expenses be limited to 2.5 percent over the second year budget for 1990 prepared in the fall of 1988. This was based on reducing the 7.8 percent amount that the test year forecast exceeded the original 1990 second year budget to the 2.5 percent amount that actual expenses have historically exceeded second year budgets on average. The Department then calculated a reduction to operating expenses (adjusted to exclude fuel, purchased power, and other items) by applying the 5.3 percent adjustment.

2. Minnesota Energy Consumers

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[9] Operating and maintenance expenses are frequently categorized as the production, transmission, distribution, customer accounts, sales, customer information, and administrative and general items in the income statement. In the original filing, those items totalled $ 850,116,000 compared to $ 713,091,000 in NSP, Docket No. E-002/GR-87-670, (August 23, 1988 at 29), with slight modification on reconsideration.

Minnesota Energy Consumers (MEC) recommended that operating expenses be reduced by $ 2,997,000 to remove costs deferred into the test year from prior periods. MEC also recommended a $ 20,108,000 normalization adjustment to insure that rates only reflect the **[*48]** cost of providing efficient electric service for the test period.

MEC calculated its adjustment by reviewing specific items and identifying specific items it believed had been deferred into the test year. Those items included amounts for line clearance, delayed commitments, deferred maintenance, deferred outage, and deferred costs [10]. MEC contended NSP should be held to its goal of maintaining cost increases within the general rate of inflation. MEC calculated its adjustment by beginning with the actual operating expenses for 1987 and escalating those costs by the Consumer Price Index (CPI)-Urban rate to 1990 [11].

3. North Star Steel Company

North Star Steel Company (NSS) recommended that no increase in rates be allowed on grounds that NSP's 1990 budget is not based on any actual financial results and is not sufficiently verifiable for ratemaking purposes.

NSS stated it was unable to produce an alternative historical test year analysis due to lack of time and data. NSS did illustrate the volatility of departmental operating **[*49]** expenses, showing that expenses increased 11.5 percent from 1987 to 1988 (a test year), decreased 3.4 percent from 1988 (a test year) to 1989, and increased 16.9 percent from 1989 to 1990 (test year in this case).

4. The ALJ

The ALJ recommended no adjustment to operating expenses, finding that the Company's witnesses were not dishonest or incompetent. He also found that the Company's operating expenses in the last fiscal year were not a reliable indication of reasonable and necessary operating expenses, because the Company had deferred many expenses that year to avoid filing a rate case.

B. The Company's Position

1. Historical Dependability

NSP argued that it has consistently filed its rate cases using forecasted operating expenses and that history will show the dependability of the forecasts. The Commission notes, however, that the intervenors have raised serious questions about the forecasts in this case. The evidence is clear that expenses are exhibiting roller coaster characteristics over the past four years, with the highest levels being reached in rate case test years. Although distant history may show dependability in NSP's budgets, recent history shows increasing variability. **[*50]** This increasing variability brings a need for more complete review. Rates are set on a prospective basis and cannot be justified on the basis that distant history was dependable.

Furthermore, the Company did not request that rates be set somewhere along the roller coaster curve. Instead, NSP asked the Commission to set rates above the highest point that can be located on the roller coaster.

The Commission cannot determine just and reasonable rates based on the mere fact that NSP has spent, or promises that it will spend, the forecasted expense money. Under *Minn. Stat. § 216B.16*, subd. 6 (1988) the Commission is directed to consider the need for revenue sufficient for the provision of adequate, efficient, and reasonable service. The Commission must base its decision on substantial evidence showing that the claimed costs are necessary in the provision of service.

The Company has asked the Commission to find rates it agreed to in the last rate case to be unjust and unreasonable. The order in the last rate case was issued on August 23, 1988. Fourteen months later the Company

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[10] MEC Exhibit 114, Direct Testimony of Stephen R. Yurek, Schedule 8.

[11] MEC Exhibit 114, Direct Testimony of Steven R. Yurek, Schedules 9 and 10.

asked for new rates which would include an increase in total operating **[*51]** expenses of approximately $ 170,000,000. Of this amount, nearly $ 140,000,000 is attributable to operating and maintenance expense, although the intervening time was a period of relatively stable prices, increased sales, no major plant additions, automatic fuel adjustments, and a conservation cost tracker account. This necessitates careful review of the requested increase.

2. Actual Financial Results

The Company contended at oral argument that it was difficult to support its budgets without being allowed to introduce actual data. The Company's ability to introduce 1989 actual data was restricted by the ALJ, who refused to allow its introduction for updating purposes, but allowed limited portions into the record for rebuttal purposes. Mr. Flaherty testified that a budget should be compared to actual results during the year it is in effect [12]. At the hearing, however, Mr. Flaherty calculated that, based on the first two months of 1990 actual financial data, NSP would underspend its forecasted test year expenses by $ 85.8 million. At the same time Mr. Flaherty cautioned against using partial budget periods for comparison.

[*52]

Mr. Flaherty's testimony underscores the difficulty faced by the Commission. The Company finds it difficult to support its forecasts without using historical data, and the Company's witness states that a full period of actual data should be used to verify a forecast. A full period of actual data is unavailable, but actual data from a partial period indicates overbudgeting of approximately $ 85.8 million. Under these circumstances the Commission has no alternative to strict scrutiny of the budgeting and forecasting process.

3. Basis for Comparison of Test Year Forecast

NSP argued that the second year budget was not an appropriate basis for comparison with the test year forecast because the test year was not based on the second year budget. The Company recommended that the test year forecast be compared to the first year budget for 1990, which was completed in the fall of 1989. The Commission finds that the comparison to the second year budget is reasonable. With the second year budget completed many months prior to the filing of the rate case, it is less likely to be influenced by the information filed in the rate case.

In response to MEC's argument that increases in its costs **[*53]** should not exceed increases in the Consumer Price Index (CPI), NSP argued that MEC erred in beginning its calculations with fiscal year 1987. The Company pointed out that its newest major generating facility, Sherco 3, was in service for only part of that year, and that "Operating costs naturally rise as a new major generating unit goes into service." [13] However, when explaining why operating costs have increased so much when no major facilities have been added, NSP argued that increases in operating expenses in excess of the CPI can reduce the need for increases in capital costs [14]. The Commission does not believe the Company can have it both ways.

When the parties focused on the major increase in expenses from 1989 to the test year, NSP filed a massive rebuttal comparing test year costs to 1988. Compared with 1988, the Company claimed, costs increased only slightly more than the CPI. The Commission sees no reasoned basis for making actual 1988 costs the primary reference point for test year costs. 1988 is not the most recent year for which actual data is available. 1988 **[*54]** actual expenditures have not been approved by this Commission as reasonable and necessary in the provision of service. Furthermore, intentionally or not, by shifting the focus to 1988 on rebuttal, just days before hearings began, the Company deprived the parties of meaningful opportunity to review, analyze, and audit the actual expenses on which the Company tried to rest its case.

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[12] Thomas J. Flaherty, Transcript Vol. 12, page 45.

[13] NSP Exhibit No. 54, Jackie A. Currier, Rebuttal Testimony, Page 11.

[14] NSP Reply Brief, page 93.

While the record contains massive testimony arguing that costs have increased only slightly over the change in the CPI between actual 1988 data and the test year forecasts, that is not the issue. NSP is requesting an increase over the rates set in its last rate case, not an increase over actual 1988 data. When comparing costs in the last rate case order to the originally filed forecasted test year data in this case, NSP is requesting an increase in jurisdictional operating expenses of nearly 20 percent, including an approximately $ 30 million increase in administrative and general expenses. On a total operating expense basis, NSP has requested an increase far in excess of the change in the CPI. NSP has not explained or justified the need for these massive increases in this record.

1988 was the test year **[*55]** in the last rate case. Throughout this record, NSP has insisted that to evaluate the earned rate of return for any given year, the actual data must be normalized. The August 23, 1988 rate case order contains the 1988 normalized data, which the Company stipulated to as representing the necessary and reasonable costs of providing service in 1988. The data was developed using the same budgeting and forecasting system relied upon in this case. It is important to note that the rates set in reliance upon this data allowed the Company to earn in excess of its authorized rate of return on an actual basis for 1988 [15].

4. Competitive Pressures

Mr. Flaherty testified that competitive pressures mandate low prices and remove the Company's incentive to inflate its forecasts. [16] At hearing, however, Mr. Flaherty testified that he had not performed a review of competition within NSP's service area. [17] The Commission notes that, for the most part, electricity is still provided in a monopoly environment. The Commission finds that the Company has not presented credible evidence establishing that competitive pressures play a **[*56]** major role in protecting the general body of ratepayers from excessive rates.

5. Budget Bases

NSP witness Flaherty indicated that the budget should reflect historical performance and should be well documented. [18] Yet, the record clearly indicates that various responsibility centers begin their respective budget processes with different bases. The Commission recognizes that the Company may be able to run its day-to-day operations with such budget procedures. However, with different responsibility centers using different starting points, there is no continuity of basic assumptions in the overall budget. Without this continuity, the Commission is prevented from tying the forecast to historical performance.

Determining the assumptions on which the overall budget is based is further complicated by Company statements that the 1990 test year forecast is based on the expenses that the Company foresees as necessary in 1990. [19] Despite the admitted need to compare to history, it is not clear **[*57]** what the test year data is based on. This further amplifies the need for support of the projected numbers. When the Company files a rate case requesting the largest rate increase in its history based on a vision of what is needed in the future, the need for justification, verification, and testimony supporting the vision are great.

NSP stated that its budgeting and forecasting system includes continuous updates. While this may be very useful for day-to-day operations, the Commission finds little comfort in continuous updates to forecasts once rates are set. It is critical that the expense forecasts used in the rate case reflect the actual costs of providing service. Once rates are set, they cannot be adjusted up or down to reflect continuous updating.

6. Deferred Expenses

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[15] General Rate Petition, Volume 3 of 4, Section A, Schedule A-1.

[16] NSP Exhibit 82, Thomas J. Flaherty, Rebuttal Testimony, Page 58.

[17] Thomas J. Flaherty, Transcript Vol. 12, Page 44.

[18] NSP Exhibit 82, Thomas J. Flaherty, Rebuttal Testimony, Page 20.

[19] Ronald H. Clough, Transcript Vol. 6, Page 26.

Parties raised concerns that test year expenses are considerably higher than expenses for 1989, and that certain costs have been deferred into the test year. NSP responded with a massive rebuttal filing on March 27, 1990. That filing included rebuttal testimony from at least seven witnesses addressing operating expenses. [20] In general, NSP chose to rebut **[*58]** the concerns raised by the parties by arguing that 1989 is not a normal year for purposes of comparison with test year expenses. The Company stated it had cut costs significantly in 1989 in order to avoid filing a rate case any earlier than it did. When it could no longer defer certain costs, the costs were reinstated and the present rate case was filed. NSP stated that those cost-cutting efforts also explain the roller coaster nature of expenses in the years before and after 1989.

NSP argued in its rebuttal that 1988 was a more appropriate comparison for test year expenses. Witnesses then explained that in comparison to 1988 actual expenses, test year DOE expenses are only 12.7 percent higher, and represent an annual increase of only 6.2 percent. The witnesses also discussed specific new or unusual expenses in their responsibility areas which would show that the increase in expenses was even less if the effect of the new and unusual items were removed.

One of the areas in which the Company allegedly cut back in 1989 was vegetation control. NSP witness Clough testified that "Trees obviously grow each year and **[*59]** it's necessary to trim back that growth." [21] He then stated that trimming costs were reduced in 1989 to avoid a rate case. Clearly, however, there is a normal level of trimming cost in every year, and that is the amount to be built into rates. The test year concept rests on the notion that the normal and ongoing costs of operating a utility can be determined with reasonable accuracy and built into rates. Rates are not set on the basis of extraordinary expenses, or on the basis of a need to "catch up" from having delayed normal and ongoing expenses in the past.

NSP minimized trimming costs in 1989 to avoid a rate case; this caused an increase in trimming costs for the test year. [22] The Commission faced this identical issue in Minnesota Power's last rate case. [23] In that case, the Commission adjusted the test year vegetation control budget because it was skewed by reduced control in the prior year. This case is much more difficult, however, because individual line items are not identifiable and adjustable, as they were in Minnesota Power. NSP filed aggregate budgets containing much less detail. At the same time, the **[*60]** Company's historical budgeting and spending patterns strongly suggest a practice of "loading" expenses into test years. The Commission cannot ascertain with reasonable accuracy how much of the requested increase is attributable to normal and ongoing operating expenses, and how much to "carryover" expenses. This contributes to the Commission's inability to rely on the Company's forecasted expenses to set new rates.

7. The Reasonableness of Specific Budget Items

The ALJ and NSP emphasized that the parties by and large did not identify specific expense items as being unreasonable, unnecessary, or inflated. The reason for this, however, was the Company's decision to file aggregate budgets which prevented identification of individual line items without great difficulty, and sometimes prevented it altogether. This decision made the credibility and reliability of the Company's budgets **[*61]** the major issue in the case, not the propriety of individual line items.

For example, when asked for an itemization of forecasted expenses by the FERC Uniform System of Accounts (USOA), NSP responded that it does not go into that much detail for ratemaking purposes. [24] This precluded systematic examination of commonly understood categories of expenses.

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[20] Currier, Doudiet, O'Leary, Larson, Clough, Tacheny, and Caskey.

[21] Ronald H. Clough, Transcript Vol. 6, Page 31 and 32.

[22] Ronald H. Clough, Transcript Vol. 6, Page 32.

[23] In the Matter of the Petition of Minnesota Power & Light Company, d/b/a/ Minnesota Power, for Authority to Change its Schedule of Rates for Retail Electric Service in the State of Minnesota, Docket No. E-015/GR-87-223, (March 1, 1988 at 47).

[24] Dennis C. Fulton, Transcript Vol. 13, Page 11.

Similarly, the Commission itself queried the Company regarding how much maintenance expense was forecasted in the test year for the transmission function. The Commission did this to assure itself that the normal maintenance costs included in the transmission function would not duplicate the costs proposed for the Manitoba line repair. The Company responded that it did not have a breakdown in the forecast for maintenance.

The Company simply did not provide enough detail to allow meaningful review of individual budget items. To require a substantive showing that individual expenses were inappropriate would essentially transfer the burden of proof to the intervenors. It would also place them at great disadvantage to the Company, which did not provide specific items to review. **[*62]** The Company's failure to classify forecasted expenses by USOA accounts prevents a comparison of the forecast to historical data, which is reported to FERC and other jurisdictions on a USOA account basis. Forecasting without regard to USOA accounts also prevents any reasonable review of the items making up the major utility functions such as production, transmission, distribution, and administrative and general expenses. Forecasting data already removes many of the normal controls associated with accounting data. Generally accepted accounting principles do not guide forecasting, and forecasts are not audited for presentation to the financial community. The absence of these formal accounting controls allows significant subjectivity in the development of test year data. To forecast without the detail required by the Uniform System of Accounts leaves the forecast virtually unverifiable.

In lieu of detailed financial testimony, the Company tended to support its operating expense budget with testimony such as "this case involves the essential costs to run an excellent utility;" [25] or "the test year forecast is based on what we foresee are the necessary expenses to run this company in **[*63]** 1990". [26] The Commission does not believe the Company provided sufficient substantiation of its alleged need for a rate increase to cover increases in operation and maintenance expenses.

NSP forecasted operating and maintenance costs in the aggregate, without the detail normally associated with utility accounts. The Commission must determine the reasonableness, prudence, and necessity of the costs included in this rate case. It cannot do this without more detailed information than that presented by the Company.

8. Unorthodox Accounting Methods

Determining the accuracy and reliability of the Company's forecasted budgets was further complicated in certain instances by the Company's use of unorthodox accounting methods.

NSP chose to discuss expense items on a Minnesota Company basis, rather than on a jurisdictional basis. However, many of the schedules were headed <u>Northern States Power Company (Minnesota) Electric Utility-State of Minnesota.</u> This heading suggests that the schedule is presenting data at the Minnesota jurisdictional level, when it is not. **[*64]** NSP witness Fulton agreed that the headings on schedules should indicate on what basis the schedules are reporting, but do not in the case of Ms. Currier's schedules. [27] The same problem exists with the schedules of many other NSP witnesses. Then, NSP chose to file rebuttal in a different format from that used by the intervenors, reporting electric operating expense by NSP FERC account rather than by Business Unit and Corporate areas. [28] Although these issues are not substantive, they consumed over 50 pages of Transcript volume 7 as intervenors struggled to understand which numbers belonged with which accounts. This diversion of intervenors' time and resources compounded the usual difficulties of analyzing and trying a rate case within the statutory ten month time period. *Minn. Stat. § 216B.16*, subd. 2 (1988).

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[25] NSP Exhibit No. 1, Direct Testimony of James J. Howard, page 5.

[26] Transcript Vol. 6, page 26, Ronald H. Clough.

[27] Dennis C. Fulton, Transcript Vol. 13, pages 9 and 10.

[28] NSP Exhibit No. 54, Jackie A. Currier, Rebuttal, Page 5.

Furthermore, approximately $ 3.9 million of items which would normally be capitalized were shifted to operating expense, a major accounting change. [29] The witness on this issue did not know whether or not the **[*65]** Commission has been notified of the accounting change. This is highly improper. Statutes and rules [30] give the Commission authority over utility accounts. The Commission must be petitioned for accounting changes by the utilities. Without direct Commission oversight, utilities could manipulate their accounts in a manner contrary to the public interest. Again, the Company's failure to present information in recognizable and usable form compounded the complexity of this case, which would have been complex under the most favorable circumstances.

9. Forecasted Property Tax Increase

The Company pointed to an expected $ 17 million property tax increase as one factually supported increase in test year expenses. Although the property tax increase is also a forecasted amount, it does have some factual support in the record.

General rate increases require more than one cost increase to support them, however. While property tax expenses increase, other expenses may decrease. The Company's total gas and electric depreciation expense, **[*66]** for example, dropped $ 9.0 million in September of 1989, with no concomitant reduction in rates. [31] Revenues may increase or decrease as well. The Company forecasted substantially higher sales revenues for the test year than were factored into the rates set in the last rate case. In short, property taxes are only one part of the ratemaking equation. Too many factors remain unknown for the Commission to solve the equation.

10. The Company's Maintenance of Comparatively Low Rates

NSP frequently pointed out that its rates are low in comparison with those of other utilities. The Company does have a record of providing good service at relatively low rates; the Commission prides itself on its role in that accomplishment. Low rates do not constitute grounds for a rate increase, however. To justify a rate increase, the Company must show by a preponderance of the evidence that existing rates are unjust and unreasonable.

C. Conclusions

Based on the information in this record, **[*67]** the Commission cannot determine with reasonable certainty the amount of operating expense necessary to provide service. The Commission cannot determine which point on the roller coaster forecast and spending curve represents the best estimate of reasonable and necessary expenses. If Mr. Flaherty's calculations hold true, NSP's expenses may be $ 85 million less than claimed in the forecast, an amount sufficient to more than eliminate the entire increase recommended by the ALJ. The Commission simply cannot set rates based on this degree of uncertainty and still satisfy its statutory responsibility.

The roller coaster spending and forecast pattern, the admitted deferral of 1989 costs into the test year, and Mr. Doudiet's comments that it is very difficult for him to manage costs not knowing what the final rates will be [32] suggest that there is a great deal of flexibility in the Company's operating and maintenance budget. The statutes require the Commission to set just and reasonable rates at a level which will allow the company to meet the cost of furnishing service. *Minn. Stat. § 216B.16*, subd. 6 (1988). The Commission cannot determine from **[*68]** this record what that cost is.

XV. PROJECTED TEST YEARS AND THE BURDEN OF PROOF

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[29] NSP Exhibit No. 31, Ronald H. Clough, Rebuttal, Page 6.

[30] *Minn. Stat. § 216B.10*. Minn. Rules 7825.02-7825.04.

[31] In the Matter of Northern States Power Company's Request for Certification of 1989 Depreciation Rates, Docket No. E, G-002/D-89-481, ORDER CERTIFYING DEPRECIATION RATES AND METHODS (September 6, 1989).

[32] James T. Doudiet, Transcript Vol. 3, Pages 31-32.

The Company has characterized intervenors' concerns about the reliability of the financial information filed in this case as an attack on the concept of the projected test year. Although some intervenors' comments may have reflected antipathy toward projected test years, that is not what led the Commission to reject the proposed rate increase.

The Commission rejects the proposed rate increase because the Company failed to carry its burden of proof; it failed to show that it is more likely than not that a rate increase is necessary. The Company's failure to carry this burden stems in part from the special proof problems presented by projected test years.

Traditionally, regulatory commissions have set rates based on detailed review of a company's finances over a twelve month period, or "test year." One treatise on utility regulation explains the test year concept as follows:

The company, with the concurrence of the commission or its staff, will generally select a "test year," frequently the latest 12-month period for which complete data are **[*69]** available. . . . More recently, due largely to inflation, a few commissions have modified the traditional historic test-year approach by using a forward-looking test year (either a partial or a full forecast) or by permitting pro forma expense and revenue adjustments.

Phillips, Charles F., The Regulation of Public Utilities, Public Utilities Reports, Inc., Arlington, Virginia, 1984, at 182.

The projected test year is an attempt to improve ratemaking accuracy and fairness. It is not a retreat from basing revenue requirements on actual financial information, but an attempt to improve the predictive value of that information by adjusting for changes which can reasonably be expected to occur.

For this reason, Commission rules on rate change procedures require companies to file extensive information on financial results from their most recent fiscal years, whether they file historic or projected test years. See, for example, Minn. Rules, part 7825.4000, A., requiring companies to file unadjusted average rate base for the most recent fiscal year, the projected fiscal year, and the test year; Minn. Rules, part 7825.4100, A., requiring operating income statements reflecting the most **[*70]** recent fiscal year, the projected fiscal year, and the test year; and Minn. Rules, part 7825.4200, requiring rate of return cost of capital schedules for the most recent fiscal year, the projected fiscal year, and the test year. Clearly, the rules anticipate an examination of both historical data and projected data, when projected test years are used.

Similarly, the Commission's rules require a utility to file projected data for the fiscal year in which the rate case is filed if the utility is unable to file at least 9 months of actual data for that fiscal year. Minn. Rules, part 3100, subp. 10, subp. 11, subp. 2 ; Minn. Rules, part 7825.4000, subps. A, B, and D; Minn. Rules, part 7825.4100, subps. A, B, E (1989). The purpose of these rules is to ensure that the Commission has at least one forecast for which actual, verifiable data will be available at the time of hearing, showing the same assumptions and approaches as the forecast used for the test year. Actual data for the fiscal year in which the rate case is filed is probative to show the accuracy and reliability of projected data, as well as to provide a historical basis for the test year forecast upon which the Commission must **[*71]** rely in setting rates.

Furthermore, Commission Orders in general rate cases have consistently expressed concern that projected test years be substantiated by as much actual data as possible and be based on reliable forecasting techniques. The Commission's 1980 Order in a Great Plains natural gas rate case, for example, traced a pattern of concern about the reliability of projected test years, citing an earlier NSP case in which such concerns were raised.

The Commission has had to face problems with projected test years in previous cases. In Northwestern Bell Telephone Company, Docket No. P-421/GR-77-1509, the Commission noted it might have dismissed the proceeding based upon lack of sufficient foundation for test year projections had the question been certified to it. In Northern States Power Company, Docket No. E-002/GR-77 611, the Commission admonished the parties that it could not make a specific adjustment to budgeted data to include actual data when it was working with a projected test year without having comparable adjustments for all related accounts. In Northwestern Bell Telephone Company, Docket No. P-421/GR-79-388, the Commission refused to allow updating of **[*72]** a future test year beyond one updating to seven months actual figures, noting the unreasonable time burden on intervenors trying to analyze and evaluate the new figures. . . .

However, it would not be possible for this Commission to reach any conclusion on a company's revenue deficiency until and unless it had an accurate and reliable test year from which to start. The test year must be believable to have any use in rate-making. The lack of a trustworthy test year was the cause of the Commission's initial rejection of this case, and only the substitution of a 1978 actual test year, which has been found to be reliable, has made possible a decision on a revenue deficiency now.

In the Matter of a Petition by Great Plains Natural Gas Company, 235 West Main Street, Marshall, MN 56258 for Authority to Change its Gas Rates for Retail Customers in the State of Minnesota, Docket No. G-004/GR-78-690, ORDER AFTER REHEARING (May 9, 1980) at 13 and 14.

Similarly, in NSP's last fully litigated rate case (The Company's last general rate case was stipulated), the Commission expressed concern about the Company's choice of test year. In that case, like this one, the test year did not begin until **[*73]** after the rate case had been filed:

The Commission has difficulty with a test year that begins several months after the date of filing. This allows only two to three months of actual data to be presented at the hearings and extends almost four months beyond the Commission's final order. Although the Commission continues to accept the concept of a future or budgeted test year, it also believes that the period selected must bear a reasonable relationship to the available historic data and the filing date. The farther beyond either that that data is selected means that the budget is less likely to reflect actual results.

In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Utility Service for Customers Within the State of Minnesota, Docket No. E-002/GR-85-558, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (June 2, 1986) at 8 and 9.

In short, the Commission's concerns in this case about verifying and substantiating the forecasted financial data on which the test year rests do not come out of a void. They are part of a long-standing Commission commitment to ensuring that projected test years have clear and substantial **[*74]** links with actual historical experience. In this case those links were much too tenuous for the Commission to believe it could set just and reasonable rates on the basis of the forecasted test year.

XVI. INITIAL ACCEPTANCE OF THE FILING

The Company and the ALJ relied in part on the Commission's initial acceptance of the rate case filing as evidence that the Company's test year documentation was adequate. Such reliance is misplaced.

The Commission typically solicits comments from potentially interested persons before formally accepting general rate case filings. The Commission does this because the filing requirements for general rate cases are complex, the evidentiary hearing process is expensive and time-consuming, and the Commission is under a ten month statutory deadline to reach a final decision. It is therefore important to detect and correct any gross filing errors immediately. The merits of the rate request are extremely complex and are beyond the scope of this preliminary review.

The November 29, 1989 ORDER ACCEPTING FILING AND SUSPENDING RATES found only that the filing was "complete and in proper form." It noted that contested case proceedings were necessary to determine **[*75]** the merits of the filing and that such proceedings would be initiated by separate Order. The November 29 Order intimated nothing as to the merits of the filing, which were properly addressed in the contested case proceeding and in this Order.

XVII. REGULATORY FAIRNESS

The Company explained in its initial filing, in its briefs, and at oral argument that it believed the focus of this case should be regulatory fairness. The Company alleged that the 11.7% rate of return allowed in its last general rate case was inadequate to the point of unfairness and represented a long-standing shortcoming of Minnesota regulation, failure to reward excellent utility performance with commensurate rates of return.

The Commission will not engage in detailed examination of the Company's regulatory fairness claim in this rate case. It would be highly unusual for the Commission to examine authorized rate of return in isolation from other traditional rate case issues. Rate of return is just one component of the ratemaking process. Rate base, revenues, expenses, capital structure, and rate design are other crucial components. Determining one issue in isolation from the others would not allow the comprehensive **[*76]** review of the Company's financial requirements necessary to set just and reasonable rates.

There are no circumstances in this case justifying a departure from these basic principles. The Company's existing rate of return was set only two years ago, in the Company's last general rate case. In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in Minnesota, Docket No. E-002/GR-87-670 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (August 23, 1988). The current rate of return was requested by the Company itself, in a joint petition seeking approval of a revenue requirements stipulation it reached with other parties in the case. Since that time, there have been no dramatic changes in the Company's access to capital markets or in the markets themselves. Under these circumstances, the Commission will not examine authorized rate of return in isolation from other ratemaking issues.

XVIII. RATE DESIGN AND CONSERVATION ISSUES

For the same reasons rate of return will not be addressed in this case, the Commission will not address rate design and conservation issues. These issues were raised in or deferred to the **[*77]** rate case because that is the appropriate vehicle for their resolution. It continues to be the proper vehicle, and the Commission will not attempt piecemeal resolution.

XIX. CONCLUSION

The Commission concludes that the Company's filed information and arguments do not provide a reliable foundation upon which to make a determination of just and reasonable rates. The adjustments proposed by the intervenors offer an alternative foundation. Since the Company's filing has so few links with historical experience, however, these adjustments are either arbitrary or extremely crude. Instead of representing NSP management's unsubstantiated judgments, they represent the intervenors' unsubstantiated judgments. Both are unsatisfactory. What is lacking is a credible factual basis for setting just and reasonable rates.

The Commission will not proceed with a rate determination based upon financial information in which it has so little confidence. The statute governing general rate increases provides that "The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change." *Minn. Stat. § 216B.16*, subd. **[*78]** 4 (1988). Elsewhere, the Public Utility Act provides,

Every rate made, demanded, or received by any public utility, or by any two public utilities jointly, shall be just and reasonable. . . . Any doubt as to reasonableness should be resolved in favor of the consumer. . . .

Minn. Stat. § 216B.03 (1988).

The Commission has a statutory duty to reject the proposed rate increase as unsupported by the record. The Commission will do so.

ORDER

1. Northern States Power Company's request for a general rate increase is denied in all respects.

2. Within 30 days of the date of this Order, the Company shall file for Commission review and approval a plan to refund to ratepayers interim rates collected under the December 29, 1990 ORDER SETTING INTERIM RATES. This refund shall include interest at the average prime rate for the collection period.

3. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Richard R. Lancaster, Executive Secretary

MN Public Utilities Commission Decisions

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