GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Utility Analyst

George McCluskey is a ratemaking specialist with over 30 years experience in utility economics. Since rejoining the New Hampshire Public Utilities Commission ("NHPUC.") in 2005, he has worked on default service and standby rate issues in the electric sector and cost allocation issues in the gas sector. While at La Capra Associates, a Boston-based consulting firm specializing in electric industry restructuring, wholesale and retail power procurement, market price and risk analysis, and power systems models and planning methods, he provided strategic advice to numerous clients on a variety of issues. Prior to joining La Capra Associates, Mr. McCluskey directed the electric utility restructuring division of the NHPUC and before that was manager of least cost planning, directing and supervising the review and implementation of electric and gas utility least cost plans and demand-side management programs. He has testified as an expert witness in numerous electric and gas cases before state and federal regulatory agencies.

ACCOMPLISHMENTS

Recent project experience includes:

Staff of the New Hampshire Public Utilities Commission – Expert testimony before NHPUC regarding default service design and pricing issues in case involving Unitil Energy Systems.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before Maine Public Utilities Commission regarding interstate allocation of natural gas capacity costs in case involving Northern Utilities.

Staff of the Arkansas Public Service Commission – Analysis and case support regarding Entergy Arkansas Inc.'s application to transfer ownership and control of its transmission assets to a Transco. Also analyzed Entergy Arkansas Inc.'s stranded generation cost claims.

Massachusetts Technology Collaborative – Evaluated proposals by renewable resource developers to sell Renewable Energy Credits to MTC in reponse to 2003 RFP.

Pennsylvania Office of the Consumer Advocate – Analysis and case support regarding horizontal and vertical market power related issues in the PECO/Unicom merger proceeding. Also advised on cost-of-service, cost allocation and rate design issues in FERC base rate case for interstate natural gas pipeline company.

Staff of the New Hampshire Public Utilities Commission – Expert testimony before the NHPUC regarding stranded cost issues in Restructuring Settlement Agreement submitted by Public Service Company of New Hampshire and various settling parties. Testimony presents an analysis of PSNH's stranded costs and makes recommendations regarding the recoverability of such costs.

Town of Waterford, CT – Advisory and expert witness services in litigation to determine property tax assessment of for nuclear power plant.

Washington Electric Cooperative, Vt – Prepared report on external obsolescence in rural distribution systems in property tax case.

New Hampshire Public Utilities Commission - Expert testimony on behalf of the NHPUC before the Federal Energy Regulatory Commission regarding the Order 888 calculation of wholesale stranded costs for utilities receiving partial requirements power supply service.

Ohio Consumer Council - Expert testimony regarding the transition cost recovery requests submitted by the AEP companies, including a critique of the DCF and revenues lost approaches to generation asset valuation.

EXPERIENCE

New Hampshire Public Utilities Commission (2005 to Present)
Utility Analyst, Electricity Division

La Capra Associates (1999 to 2005)
Senior Consultant

New Hampshire Public Utilities Commission (1987 – 1999)
Director, Electric Utilities Restructuring Division
Manager, Least Cost Planning
Utility Analyst, Economics Department

Electricity Council, London, England (1977-1984)
Pricing Specialist, Commercial Department
Information Officer, Secretary's Office

EDUCATION:

Ph.D. candidate in Theoretical Plasma Physics, University of Sussex Space Physics Laboratory.
Withdrew in 1997 to accept position with the Electricity Council.

B.S., University of Sussex, England, 1975.
Theoretical Physics

Staff Exhibit-2

Name:	**EDWARD C. ARNOLD**
Title:	**Group Manager**
Education:	MBA University of Chicago, finance concentration (1991) M.S. Industrial Microbiology, Illinois Institute of Technology (1982) B.S. Chemical Engineering, University of California, Davis (1976) B.S. Biochemistry, University of California, Davis (1976)

Career Synopsis:

As a Group Manager with Jacobs Consultancy Mr. Arnold focuses on helping clients with strategic investment decisions, project financial analysis, quantitative risk analysis (QRA), new technology development and quantitative market analysis. He has provided advisory services for some of the world's most successful petroleum refining, energy production, technology development, information services, biotech and petrochemicals production corporations, as well as for many government agencies and entrepreneurial firms.

Mr. Arnold and his group are specialists in developing and applying experience, methodology and tools that support and guide strategic investment decisions, tactical decisions and policy formulation. These quantitative, evolvable, state-of-the-art methods and tools help clients make better decisions and provide clients with critical insight into both the opportunities and the potential pitfalls of strategy implementation. They are designed to be used for and by professional business or institution managers. As appropriate, the decision support tools bring together a broad risk assessment knowledge base, scenario-analysis, discounted cash flow valuation models, Monte Carlo simulation, Options Theory, Game Theory and strategic planning fundamentals. They provide a comprehensive, insight-generating framework that is capable of simulating: (a) business environment uncertainty and (b) business management's flexibility to respond to market opportunities and competitive moves or threats in an evolving environment.

Mr. Arnold brings over 29 years of technology development, business development, strategic planning and valuation & risk analysis experience to his job. Prior to joining Jacobs Consultancy Mr. Arnold worked for UOP LLC and ThermoGen/MediChem. Significant projects completed by Mr. Arnold, during his 29 years with Jacobs Consultancy, UOP and ThermoGen/MediChem include the following:

Notable Recent Papers, Publications, Presentations, Patents:

"Making Long Term Plans in Uncertain Times," Air Products Annual Barton Creek Retreat, by Ed Arnold and Brant Sangster of Deloitte, Canada. (Austin, Texas, 2008)

"What's Ahead for North American Refining: Most Likely Scenarios," Spring 2008 Chicago Chapter AICHE Meeting

"Key Market Issues & Trends for Refining," UOP Annual North American Refiners Conference (Kananaskis, Canada – 2005)

"Game Change Ahead – What's Ahead for the Refining Business," UOP Annual North American Refiners Conference (Montebello, Canada – 2004)

"What's in Store for North American Refining; 2005 - 2015?" UOP Annual Western Refiners Conference (Park City, Utah – 2004)

"Applications of Quantitative Investment Risk Analysis to Refinery Projects," Russian Refining Technology Conference (Moscow, 2003)

"New Markets for Engineered Enzymes," The Catalyst Group Annual Catalyst Technology Conference (Houston – 2000)

"New Technology for Conversion of Methanol to Higher Value Products," World Methanol Conference (San Diego - 1999)

Holder of 5 U.S. Patents

Employment History:

Jacobs Consultancy
(2005 – present)
Group Manager

UOP
Commercial Manager - Technology Business Development Group (2004-2005)
Manager – Strategic Planning Services Group (2001-2004)

ThermoGen/MediChem (Now DeCode Genetics)
General Manager – Sales and Business Development (1999-2000)

UOP
Business Development Manager – Petrochemical Business Unit (1998-1999)
Business Development & Strategic Planning Manager (1995-1998)
Manager – Refining & Petrochemicals Technology Development (1990-1995)
Business Development Manager – Biotechnology Business Development (1985-1990)
Bio-Technology Process Development Group Leader and Manager (1979-1984)
Development Engineer (1977-1979)

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-084

Witness: **David A. Errichetti,Richard L. Levitan**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. Appendix G at page 39. Provide all calculations and data used to derive the Dracut natural gas prices based on Henry Hub spot prices.

Response:
LAI's forecast of natural gas prices at Dracut is based on two parts, the Henry Hub spot price and an adder to account for the basis differential between the Henry Hub and Dracut.

The Henry Hub prices are the NYMEX forward curve that settled on August 27, 2010.

The basis adder used to calculate the Dracut price is based on the historical relationship between Henry Hub and Dracut prices. To determine this relationship, LAI compiled daily spot prices for the period March 2003 to February 2010. For each day, the basis between Henry Hub and Dracut was calculated and expressed as a percentage of the Henry Hub price for that day. Data were provided by Bloomberg LP. Thus, the basis was expressed as a percentage adder over the Henry Hub price. These basis adders were then averaged on a monthly basis. For example, all of the January adders were average to calculate a single adder used for each January in the forecast. Those adders were then applied to the NYMEX curve. The percentage adders for each month of the forecast are shown below:

	Percentage Adder
January	48%
February	20%
March	15%
April	9%
May	6%
June	6%
July	7%
August	6%
September	5%
October	7%
November	9%
December	23%

The historic pricing data for Dracut and Henry Hub were provided as part of LAI's subscription service with Bloomberg LP. Under LAI's licensing agreement with Bloomberg the data cannot be distributed, thus preventing LAI from providing the workpapers to support these calculations. We note that LAI has a pending request to Bloomberg seeking permission to provide this data under a protective order.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-085
Page 1 of 1

Witness: **Richard L. Levitan**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. Appendix G at page 39. Provide calculations and data used to develop RFO and 2FO prices beyond their forward curve horizons.

Response:
LAI's forecasts of RFO and 2FO are based on the historic relationship between those fuels and WTI. That relationship is then applied to the WTI forward curve.

In order to determine the relationships between RFO and 2FO with WTI, LAI compiled average monthly data since 1985 for all three fuels. LAI then ran linear regressions on the monthly series separately, one to determine the coefficients of the linear relationship between RFO and WTI and one to determine the coefficients of the linear relationship between 2FO and WTI. These coefficients were then applied to the WTI forward curve for the period beyond the forward curve horizons for RFO and 2FO in order to forecast spot prices.

The historic pricing data for WTI, RFO and 2FO were provided as part of LAI's subscription service with Bloomberg LP. Under LAI's licensing agreement with Bloomberg the data cannot be distributed, thus preventing LAI from providing the workpapers to support these calculations. We note that LAI has a pending request to Bloomberg seeking permission to provide this data under a protective order.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-061
Page 1 of 2

Witness: **Terrance J. Large**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. Appendix G at page 13. Please update Exhibit G.1 to include complete data for 2010.

Response:
Please see the attached.

Data Request Staff-01
Dated: 03/04/2011
Q-STAFF-061

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
Newington Station 2010 Revenue Requirements and ISO-NE Revenue

Revenue Requirements ($000)

O&M Expense	$	6,945
Emissions Allowance		1,969
Total Non-Fuel O&M		8,914
Fuel Expense		19,787
Property Tax		654
Depreciation Expense		8,926
Return on Rate Base		7,244
Total Revenue Requirement	$	45,525

ISO-NE Market Revenue

Energy	$	22,829
Capacity		18,688
Ancillary		254
Unitil Entitlement		-
Total Revenue	$	41,771

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-056
Page 1 of 1

Witness: **William H. Smagula,Elizabeth H. Tillotson**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. Appendix G at page 13. Regarding the gross plant and accumulated depreciation values in Exhibit G.1, please respond to the following: a. Clarify whether the amounts are end-of-year amounts. b. Clarify whether the 2007 entries are the amounts recorded in the Company's books or estimates. c. Explain why the 2007 entries are $20 million and $25 million respectively higher than the 2006 entries and about $16 million and $14 million higher than the 2008 entries. d. Explain why the 2007 entries are substantially different from the December 31, 2007 balance sheet amounts reported to the Commission by PSNH for Newington Station.

Response:
The gross plant and accumulated depreciation values in Exhibit G.1 show the end of year actual amounts reflected on the Company's books. However, after further review, the 2007 amounts for gross plant value, accumulated depreciation and net plant value were incorrectly stated in Exhibit G.1. The "as corrected" and "as filed" amounts are noted below:

	As Corrected (000's)	As filed (000's)
2007 Gross Plant Value	$141,546	$160,000
2007 Accum. Depreciation	77,234	99,000
2007 Net Plant Value	$ 64,312	$ 61,000

The corrected 2007 Newington net plant value results in $368 thousand of additional return on rate base [($64,312- $61,000) x 11.13%] which increases the revenue requirements for 2007 to $52,301 from the "as filed" Exhibit G.1 of $51,933. This change is immaterial and has no effect on the conclusions of the study.

Public Service of New Hampshire

A Northeast Utilities Company

PSNH Energy Park
780 North Commercial Street, Manchester, NH 03101

Public Service Company of New Hampshire
P.O. Box 330
Manchester, NH 03105-0330
(603) 669-4000
www.psnh.com

The Northeast Utilities System

July 8, 2011

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: Docket No. DE 10-261 – PSNH 2010 Least Cost Integrated Resource Plan

Dear Secretary Howland:

During the course of recent discovery in PSNH's Least Cost Integrated Resource Plan proceeding, two issues have arisen that warrant identification to the parties in the docket. The first issue is the realization that New Hampshire Renewable Portfolio Standard (RPS) costs have been allocated to PSNH's generating units, including Newington, for accounting purposes since the program's inception in 2008. While RPS costs are clearly an expense associated with providing energy service, RPS costs are a function of load served and have nothing to do with the operation or dispatch of specific generating units. The allocation occurred because at the outset of the RPS program, RPS costs were accounted for in the same fashion as air emissions costs and were therefore allocated to the generating units. As a result, section G (Newington Station Continued Unit Operation Study) of PSNH's September 30, 2010 filing requires revision to tables G.1 and G.2 and text on pages 14 and 18 (Bates pages 000197 and 000201, respectively) that referenced the tables. PSNH is filing seven copies of revised pages to the filing along with "redlined" pages showing the changes that were made. In addition, data responses to Staff 1-061, OCA 2-033, and OCA 2-039 which referenced the tables required modification and those modified responses are being provided to the parties.

The second issue relates to the computation of 2010 energy revenues for the months of August and September 2010 in three data responses previously filed. PSNH has determined that generation in those two months had been valued in both the day ahead and the real time energy markets and resulted in an overstatement of 2010 energy revenues. As a result, PSNH is providing the parties with revised data responses to Staff 1-060, Staff 1-068 and OCA 2-033.

The changes to the filing are as follows:

- Pages 13, 14, 18, and 19 (Bates pages 000196, 000197, 000201, and 000202) from Section G, Newington Station CUO Study: As noted above, in the calculation of expenses in the historical revenue requirements, Newington Station was being allocated NH Renewable Portfolio Standard (RPS) costs in 2008-2010. These costs were being included in the line item shown as Emissions Expense. As a result, PSNH modified tables G.1 and G.2, text in the report that referred to the figures.

Please replace the existing pages from the September 30, 2010 filing with the revised pages attached hereto.

Electronic copies of this filing have been provided to the Office of Consumer Advocate and to the persons on the attached service list, pursuant to Puc 203.02.

Very truly yours,

Terrance J. Large, Director
Business Planning and
Customer Support Services

Enclosures
cc: Service List

Clean pages

Exhibit G.1 shows the estimated historical revenue requirements for Newington Station and wholesale product sales over the last five calendar years, 2005 through 2009, and the first six months of 2010. The revenues summarized toward the bottom of the table represent the Station's sale of energy, capacity, and ancillary services in the various wholesale product markets administered by ISO-NE. The exhibit shows an estimate of Newington Station's total historical revenue requirements as would be used in the Energy Service rate setting process. Data provided therein are approximately the same as data provided to the NHPUC in previous discovery requests.

Exhibit G.1: Recent Revenue Requirements, 2005-2010 YTD June

(thousands of dollars)	2005	2006	2007	2008	2009	1H 2010
Expenses						
Non-Fuel O&M with Indirects						
Other than Emission Allowances	$13,350	$9,136	$7,640	$7,863	$7,697	$2,900
Emission Allowances Expense	$1,497	$464	$315	($32)	$288	$49
Total Non-Fuel O&M	$14,847	$9,600	$7,955	$7,831	$7,984	$2,949
Fuel and Fuel-Related Expense (Note 1)	$68,344	$22,492	$30,476	$15,784	$16,808	$5,844
Property Tax	$925	$908	$1,034	$966	$821	$189
Depreciation Expense	$3,408	$3,447	$3,300	$8,868	$8,934	$4,464
Total Expenses	**$87,524**	**$36,447**	**$42,765**	**$33,451**	**$34,547**	**$13,445**
Plant Values						
Gross Plant Value	$139,989	$140,340	$160,000	$143,944	$144,307	$144,161
Accum. Depreciation	$71,739	$74,382	$99,000	$85,714	$94,089	$98,576
Net Plant Value	$68,250	$65,958	$61,000	$58,230	$50,218	$45,585
Working Capital	$1,830	$1,184	$981	$1,181	$1,215	$942
Year End Fuel Inventory	$23,108	$28,079	$18,477	$32,019	$26,879	$25,143
Emissions Inventory (NOx, SOx, CO2)	$5,917	$1,280	$1,408	$604	$785	$367
Accumulated Deferred Income Tax	($5,467)	($3,410)	($3,520)	($4,536)	($4,424)	($3,656)
Material & Supply Inventory	$4,899	$3,636	$4,024	$4,287	$4,571	$3,370
Total Rate Base	$98,538	$96,726	$82,370	$91,785	$79,244	$71,751
Average Return on Rate Base	10.91%	10.61%	11.13%	10.80%	10.98%	10.63%
Return on Rate Base	**$10,750**	**$10,263**	**$9,168**	**$9,913**	**$8,701**	**$3,814**
Revenue Requirements	**$98,274**	**$46,710**	**$51,933**	**$43,363**	**$43,248**	**$17,259**
Revenues						
Energy	$88,928	$21,304	$27,013	$14,654	$13,591	$5,439
Capacity	$927	$2,224	$14,023	$15,840	$18,537	$9,591
Ancillary	$381	$110	$28	$13	$99	$60
Unitil Entitlement	$3,386	$2,336	$2,610	$1,810	$0	$0
Total Revenue	**$93,621**	**$25,974**	**$43,674**	**$32,317**	**$32,228**	**$15,090**

Note: Fuel costs for 2007 total $36,384K but are shown net of $5,908K related to oil resale transactions.

D.1.2. Treatment of Expenses and Revenues for CUO Analysis

This section discusses the various expense, rate base, and revenue line items shown in Exhibit G.1 with respect to Newington Station's historical revenue requirements and revenues. While the categories of expenses, rate base elements, and revenue sources are the same in a CUO study as in a revenue-requirements study, there are certain analytic differences in what expenses and rate base elements should be included in a CUO analysis. This section describes the "bridge" to the CUO analysis, whereby certain of the expense and rate base items are necessarily treated differently. The focus here is on the distinction between total costs and the incremental or going-forward costs appropriately allocable to PSNH's customers in the broader context of the CUO analysis.

O&M Expenses. Non-fuel O&M expenses associated with Newington Station include labor and benefits, scheduled and major maintenance, emission allowances, and an allocation of PSNH's and NU's administrative and general expenses. Primarily due to prior capital investments in Newington Station being depreciated and the decreased capacity factor experienced in the last few years, the current costs of operating Newington Station are low. Staffing reductions implemented over the past few years have resulted in additional savings. Direct, loaded, fixed O&M costs going forward are currently estimated to be less than $7.5 million per year. This compares favorably to $8.0 million in 2009, adjusted for inflation. Assuming continued operation, O&M expenses continue to be incurred over the forecast period. Emissions allowance expense includes the cost of any federal or state allowances for emissions from Newington Station. These typically include NO_x, SO_x, and CO_2 expenses associated with the annual tons of Newington Station's emissions. In the going forward CUO analysis, emission expenses have been simulated over the forecast period for multiple scenarios and are included with the fuel-related expenses.

Fuel and Fuel-Related Expenses. Fuel and fuel-related O&M expenses are variable costs associated with Newington Station operations and include fuel purchases, shipping, handling, and fuel additives needed to generate electricity by operating the plant and manage emissions. In the CUO analysis, fuel and fuel-related O&M expenses have been simulated over the forecast period for multiple scenarios.

Property Tax Expense. The property tax expense listed in Exhibit G.1 is Newington Station's property tax based on the combined property tax assessments by the Town of Newington and the State of New Hampshire. PSNH has had frequent negotiations with the Town of Newington to keep tax bills reasonably in check. This is done to ensure that Newington's assessors remain informed regarding the issues that impact the market value of Newington Station. In the CUO analysis, property taxes continue to be paid for Newington Station if the unit continues to operate.

Depreciation Expense. The depreciation expense listed in Exhibit G.1 is the amount of depreciation that customers pay for plant capital costs and capital addition investments in Newington Station. The remaining book life for depreciation purposes is currently set at 2014 and therefore the undepreciated plant balance is spread over that remaining time period. PSNH periodically looks at the expected life as defined on the books and adjusts the end date defined for depreciation purposes. For purposes of this CUO analysis, when the

Historical records show that Newington had expenses of $34.5 million in 2009. Expenses ranged from $33.5 million to $87.5 million in the prior four years. These expenses include depreciation expense, which was about $8.9 million in 2008 and 2009, but much lower in the prior years. Revenue requirements also include return on rate base, which totaled $8.7 million in 2009, down from as much as $10.8 million in the four preceding years. Hence, the total revenue requirement for Newington Station was $43.2 million in 2009. In 2009, the market value of the wholesale products sold through ISO-NE's capacity and energy markets totaled $32.2 million. The difference between the revenue requirement and the value of the wholesale products in 2009 was $11.0 million. The net revenue requirement was about the same in 2008 and has fluctuated in the prior years over the five-year historical period. While this calculation is appropriate as part of the rate-setting procedure for PSNH, it does *not* signify a negative net benefit borne by PSNH's customers of continued operation of Newington Station.

A positive net revenue requirement does not mean that PSNH's customers would be better off if Newington Station had been retired prior to the beginning of 2010. The net plant book value was $50.2 million at the end of 2009. Consistent with public utility law, if PSNH were to accelerate the retirement of Newington Station, this value net of salvage, would be recovered from PSNH's customers over some number of years as a stranded cost. A return on the remaining book value of Newington Station would be included in PSNH's rates. If we assume that salvage value is negligible, then the present value of the stranded cost recovery would be approximately the same as the present value of the future depreciation and return on net plant value revenue requirements for Newington Station.

To further illustrate the distinction between a rate-setting analysis and a CUO analysis, LAI has "backcast" Newington Station's "going-forward" costs over the historic period, 2005 through 2009, shown in Exhibit G.2. From a CUO study perspective, the meaningful measure of the annual "going-forward" net costs of the station would be its expected expenses, including depreciation of only *incremental* capitalized expenditures made from 2005 through 2009, plus return on incremental plant value, working capital, and inventory rate base, less market revenues, adjusted for any hedge or insurance value. In this simplified illustrative analysis, incremental capitalized expenditures are assumed to be zero. In actuality, PSNH incurred some capital expenditures during this period in order to maintain plant efficiency.[13] The purpose of this example is only to reinforce the explanation that depreciation and return on rate base for past investments are properly omitted from consideration in a CUO study.

For 2009, inventories and working capital was $29.0 million ($79.2 million total rate base less $50.2 million net plant value). Therefore, when we apply the return on rate base of about 11%, the return requirement is $3.2 million. Gross going forward costs are the sum of expenses, excluding depreciation, of $25.6 million, plus the $3.2 million inventories plus working capital return charge, or $28.8 million. With 2009 market revenues of $32.2 million – again, assuming no incremental capital expenditures – it would have provided a net benefit (reduction in net going forward costs) to customers of $3.4 million. Applying the same assumption of no capital expenditures from 2005 through 2009, the largest net benefit

[13] Also, we are using a single known historical outcome of operating expenses and revenues rather than considering the economic impacts of uncertainty on expected market valuation and additional insurance premium value.

would have been $6.2 million in 2005. In four of five years Newington Station would have provided a net economic benefit to its customers. In one of the five years, 2006, Newington Station would have provided a net cost (disbenefit) when the annual net going-forward cost was $10.3 million. Over the past five years, the average net benefit would have been positive.

Exhibit G.2: Recent Incremental Revenue Requirements, 2005-2009 (No CapEx)

			2005	2006	2007	2008	2009
a		Net Plant Value	$68,250	$65,958	$61,000	$58,230	$50,218
b		Average Rate of Return	10.91%	10.61%	11.13%	10.80%	10.98%
c		Total Expenses	$87,524	$36,447	$42,765	$33,451	$34,547
d		Less Depreciation Expense	$3,408	$3,447	$3,300	$8,868	$8,934
e	e=c-d	Incremental Expenses	$84,116	$33,000	$39,465	$24,582	$25,613
f		Total Return on Rate Base	$10,750	$10,263	$9,168	$9,913	$8,701
g	g=a*b	Less Return on Rate Base Net Plant Value	$7,446	$6,998	$6,789	$6,289	$5,514
h	h=f-g	Return on Wkg Capital & Inventories	$3,304	$3,265	$2,378	$3,624	$3,187
i		Market Revenues	$93,621	$25,974	$43,674	$32,317	$32,228
j	j=e+h-i	Incremental Revenue Requirements	($6,201)	$10,291	($1,831)	($4,111)	($3,428)

D.2. Recent Operational Performance

The request for this CUO study was triggered by the observation that the capacity factor of Newington Station has declined in recent years. A lower capacity factor reduces the economic attractiveness of the Station, all else equal, by increasing the average fixed cost per MWh. A key question is whether the recent downward trend in capacity factor represents a new, less utilized permanent state, or whether the lower recent capacity factors are transitory.

Importantly, capacity factor – defined as net energy generation divided by potential energy generation over all hours in the period – is not the only key physical operational indicator of Newington Station's value to customers. Other key physical operating performance indicators include service factor, availability, and number of starts. Service factor – defined as service hours divided by all hours in the period – is closely related to capacity factor but has the advantage of indicating, in relation to capacity factor, the amount of time the unit operates at less than full load. Operation at less than full load provides customer benefits by being able to quickly increase loading whenever the economic opportunity or reliability need arises in the real time market. The number of starts is also a useful indicator of the unit's value by showing the ability to take advantage of positive spark spreads.

Exhibit G.3 shows Newington Station's annual operating performance from 2000 through 2009, and monthly reporting for 2010 through July. Prior to 2003, Newington Station also had lower annual capacity factors than in the 2003 to 2005 period, when the Station

Staff Exhibit-7

Newington Station
Comparison of Revenue Requirements
and Market Revenues

		2005	2006	2007	2008	2009	2010
Expenses							
Non-Fuel O&M							
Other than Emission Allowances		$13,350	$9,136	$7,640	$7,863	$7,697	$6,945
Emission Allowances		$1,497	$464	$315	-$32	$288	$49
Total Non-Fuel O&M		$14,847	$9,600	$7,955	$7,831	$7,985	$6,994
Fuel and Fuel-related Expense		$68,344	$22,492	$30,476	$15,784	$16,808	$19,787
Property tax		$925	$908	$1,034	$966	$821	$654
Depreciation Expense	$6,147	$3,408	$3,447	$3,300	$8,868	$8,934	$8,926
Total Expenses		$87,524	$36,447	$42,765	$33,449	$34,548	$36,361
Return on Rate Base							
Gross Plant Value		$139,989	$140,340	$141,546	$143,944	$144,307	$144,161
Accum. Depreciation		$71,739	$74,382	$77,234	$85,714	$94,089	$98,576
Net Plant value		$68,250	$65,958	$64,312	$58,230	$50,218	$45,585
Working Capital		$1,830	$1,184	$981	$1,181	$1,215	$942
Year End Fuel Inventory		$23,108	$28,079	$18,477	$32,019	$26,879	$25,143
Emissions Inventory		$5,917	$1,230	$1,408	$604	$785	$367
Accum. Deferred Income Taxes		-$5,467	-$3,410	-$3,520	-$4,536	-$4,424	-$3,656
M&S Inventory		$4,899	$3,636	$4,024	$4,287	$4,571	$3,370
Total Rate Base		$98,537	$96,677	$85,682	$91,785	$79,244	$71,751
Average Return on Rate Base		10.91%	10.61%	11.13%	10.80%	10.98%	10.63%
Return on Rate Base		$10,750	$10,257	$9,536	$9,913	$8,701	$7,627
Total Revenue Requiremments		$98,274	$46,704	$52,301	$43,362	$43,249	$43,988
Revenues							
Energy		$88,928	$21,304	$27,013	$14,654	$13,591	$21,459
Capacity		$927	$2,224	$14,023	$15,840	$18,537	$18,688
Ancillary		$381	$110	$28	$13	$99	$254
Unitil Entitlement		$3,386	$2,336	$2,610	$1,810	$0	$0
Total Revenue		$93,622	$25,974	$43,674	$32,317	$32,227	$40,401
Net Profit/Loss		-$4,652	-$20,730	-$8,627	-$11,045	-$11,022	-$3,587
Energy Net Revenue		$19,087	-$1,652	-$3,778	-$1,098	-$3,505	$1,623

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-059
Page 1 of 1

Witness: **Terrance J. Large,Robert A. Baumann**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Ref. Appendix G at page 13. Regarding Exhibit G.1, please explain how the annual return on rate base was calculated.

Response:
The annual return on rate base shown on Exhibit G.1, page 13 represents the actual return for each year, derived by taking a simple average of the four actual quarterly returns. The annual return is calculated based on the actual weighted average cost of debt, the weighted average cost of equity using the approved ROE and the related taxes.

Shown below is the 2009 actual annual return calculation:

	Cap. %	Cost	Weighted Cost	Tax Gross up	Total Cost
Long Term Debt	49.52%	5.365	2.66	---	2.66%
Equity	50.48	9.810	4.95	3.37%	8.32
Return on Rate Base	100.00%		7.61%	3.37%	10.98%

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To: George McCluskey
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

From: Ed Arnold (Jacobs Consultancy)

Subject: Review of LAI Valuation Model used for CUO Study for Newington Station

Introduction

Public Service Company of New Hampshire (PSNH) filed its 2010 Least Cost Integrated Resource Plan (LCIRP) on September 30, 2010 in Docket DE 10-261. The LCIRP included a Continuing Unit Operations (CUO) study for PSNH's Newington Station as required by the New Hampshire Public Utilities Commission in Order No. 25,061, issued on December 31, 2009 in Docket No. DE 09-180.

Initially designed to burn residual fuel oil (RFO) or bunker crude, Newington Station can now burn natural gas as well as RFO. In addition, the plant has operational flexibility ranging from 60 MW to 400 MW.

Levitan & Associates, Inc. (LAI), a management consulting firm that specializes in the energy industry, was hired by PSNH to conduct the CUO study for Newington Station. LAI's methodology for determining the net present value of Newington Station takes account of the operational flexibilities noted above.

The CUO study is based on historical and projected financial and operating data provided by PSNH. As part of their analysis LAI was responsible for the development of an independent forecast of capacity prices in New England and the calibration of Day Ahead (DA) and Real Time (RT) energy prices and fuel prices at Newington Station to available forward market energy and fuel prices. Using these energy and fuel prices as initial equilibrium values, LAI built and ran an asset valuation model system to estimate the value of Newington Station over the ten-year analysis period, 2011 through 2020.

Jacobs Consultancy's role in this proceeding is to assist the New Hampshire Public Utility Commission Staff (Staff) in its evaluation of whether LAI's modeling of the value of Newington Station is reasonable.

Jacobs Consultancy has segmented its review into two parts, review of (1) Model Structure and (2) Model Performance (or function).

The review of model structure will focus on the basic design of the model versus LAI's objective and in comparison to traditional and state of the art methods. It will also focus on input data selection.

The review of model performance will focus on the actual model run results and whether or not they appear reasonable. We sometimes use model run results as a basis for commenting on model structure.

Model Review Part 1: A Review of Model Structure

Jacobs Consultancy was not given access to LAI's proprietary Newington Station performance valuation model system, and therefore Jacobs could not review and perform in-depth testing of the actual models.[1]

This meant that Jacobs Consultancy's review was limited to (a) reading LAI's description of the model structure in summary reports,[2] (b) reviewing LAI's responses to questions issued on those reports and (c) analyzing the results of model re-runs based on different inputs.

Software Used for Model System

LAI used the following software systems as the foundation for their model system:

- Microsoft® Excel spreadsheet calculation software
- Risk Solver Monte Carlo simulation program (running as a Microsoft Excel overlay)
- MATLAB® technical computing system for algorithm development, data visualization, data analysis, and numeric computation.
- Stata® data statistical analysis program

Jacobs Consultancy is familiar with and often uses all of these programs expect Stata. Instead of Stata, Jacobs uses an alternate data statistical analysis program that is similar to Stata in

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[1] This is the typical approach that Jacobs Consultancy would use.
[2] The two reference documents were *Appendix G*, titled *Newington Station Continuing Unit Operations Study*, from the *Public Service Company of New Hampshire Least Cost Integrated Resource Plan*, September 30, 2010 and the *Newington Station Continuing Unit Operations Study: Modeling System Overview.*

function. In the opinion of Jacobs Consultancy all of these foundation programs used by LAI are well-suited to LAI's work objective and model structure, as we understand it. Their work objective is to estimate the net present value (NPV) of Newington Station over the next 10 years, despite high levels of uncertainty in its business environment.

The Individual Models or Calculation Procedures

The LAI model system incorporated ten different models or calculation systems to arrive at an estimate of net present value for the Newington Station asset. Jacobs Consultancy will review each of the ten models or calculation procedures individually.

Model 1a: Natural Gas Monthly Forwards Pricing Models

LAI's overall approach for modeling natural gas prices at Newington Station over the 10 year analysis period is acceptable, with reservations. These prices are based on a forecast of natural gas prices at the Dracut trading point in Massachusetts. This forecast is itself based on two parts, the Henry Hub spot price and an adder to account for the basis differential between the Henry Hub price and Dracut price.

The basis differential used to calculate the Dracut price is based on the historical relationship between actual Henry Hub and Dracut prices. To determine this relationship, LAI compiled daily spot prices for the period March 2003 to February 2010 based on data provided by Bloomberg LP. These daily basis differentials were then averaged on a monthly basis. Using the historical relationship between actual reference prices (Henry Hub spot) and actual prices at a local trading point (Dracut spot) to construct a forecast of prices at the local trading point is, in theory, reasonable. Constructing monthly average basis differentials that are then used for each month of the forecast period is also common practice. However, Jacobs Consultancy was not given access to the Bloomberg natural gas price data. Consequently, we have been unable to independently verify the accuracy of the monthly average basis differential used by LAI to develop the forecast of natural gas prices at Dracut.

As noted, natural gas prices at Newington Station are based on a forecast of prices at Dracut. Specifically, in the model the daily natural gas price at Newington Station equates to the daily natural gas prices at Dracut plus a 75 cents/MMBtu premium in the months January-February and a 17.5 cents/MMBtu premium in all other months. However, based on a review of 2010 invoices from Newington Station's natural gas supplier, Jacobs Consultancy believes that the basis differential for the months January-February should be 80 cents/MMBtu and 84 cents/MMBtu for all other months.

LAI used the August 27th, 2010 Nymex natural gas forwards (Henry Hub) as a basis for forecasting natural gas prices into the future. This is an adequate forecast method, although Jacobs believes a more useful method for estimating the future value of Newington Station would have been a multiple scenario type method.[3] This would have allowed a Study reader to see the potential value of the power plant over a wide range of reasonably possible futures and also to pick the one or two futures they considered to be most likely as the basis for their valuation.

Model 1b: RFO and 2FO Monthly Forwards Pricing Models

LAI's forecasts of RFO and 2FO are based on the historic relationship between those fuels and WTI. Those relationships were then applied to the WTI forward curve that settled August 27, 2010. In order to determine the relationships between RFO and 2FO with WTI, LAI compiled average monthly data since 1985 for all three fuels based on data provided by Bloomberg LP. As with natural gas, Jacobs was not given access to the Bloomberg price data and, as a result, was unable to independently verify the accuracy of LAI's calculations underlying the RFO and 2FO price forecasts.

Leaving aside the concern over our access to data, Jacobs Consultancy is of the opinion that the monthly forward RFO and 2FO prices estimated for Newington Station (See Exhibit G.9 in the Newington Station CUO Study) do not represent the most likely near-term scenario (over next 1 to 5+ years). On this basis Jacobs recommended that LAI rerun the valuation model with the RFO/Henry Hub Natural gas and 2FO/Henry Hub Natural gas price ratios shown in Table 1. These price ratios are wider than those forecast by LAI (via their use of futures strips and historical correlations between WTI prices and RFO and 2FO prices).

Table 1
Recommended 1%S RFO and 2FO Price Ratios off Henry Hub Natural Gas
(Assume linear trend between 2011 and 2020 price forecasts)

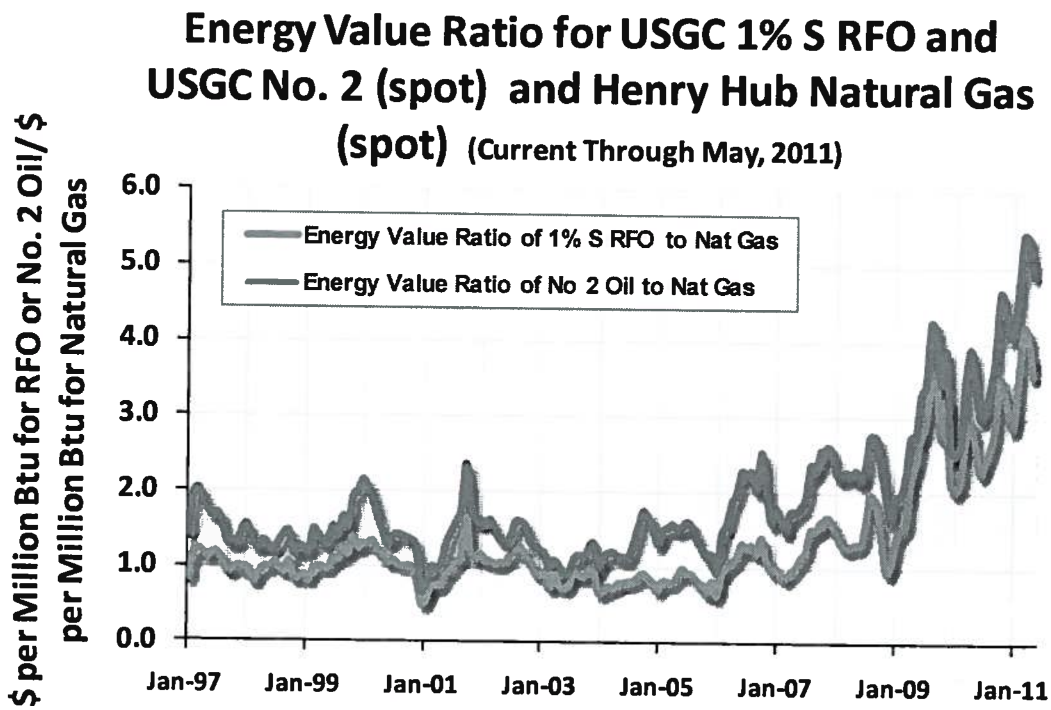
	2011	2020
Ratio of 1% S Resid to Nat Gas $/MM Btu Cost	4	3.5
Ratio of No. 2 Oil to Nat Gas $/MM Btu Cost	5	4.5

This view of price differentials is based upon a relatively conservative scenario viewed as having reasonable potential for the 2011 to 2016 period. The 5 year scenario has been extrapolated to 2020. Jacobs believes that a conservative price ratio scenario is more valid for the Newington Station analysis. The scenario is based upon a delayed re-approach to near-parity Btu-pricing between RFO and natural gas. The basis for this scenario is that even though we will see gradually increasing tightness in the North American natural gas market, over most

[3] Since, rarely, is any single forecast ever correct. The Nymex strip is, essentially, the combined view of numerous speculators and hedgers. They have often been incorrect. A scenario type method would have generated multiple valuations for the power station, which each valuation based on a different view of where the business environment (and perhaps the plant operating philosophy) was headed.

of the next 5 to 10 years it will be relatively slow to develop. We will see more upward price pressure on worldwide oil prices than on natural gas prices.[4] As a point of reference Figure 1 illustrates the historical reference $/MM Btu prices for the RFO, 2FO and natural gas.

Figure 1



Model 2: Energy Monthly Forwards Pricing Models

LAI's overall approach for modeling market energy prices at the Newington Station node over the 10 year analysis period is, in general, based upon acceptable practices. Jacobs bases this view on the following conclusions:

- The use of the NYMEX monthly forwards for MassHub as the starting point in the development of the forecast of market energy prices is reasonable.
- The use of shaping factors to calculate monthly energy prices after 2012 when the NYMEX forwards converge to annual products is standard practice.
- Adjustment of the MassHub price forecast based on the historical basis differential between MassHub and the Newington node is a reasonable approach to developing the forecast of energy prices at Newington through 2014.

4 . In terms of uncertainty, Jacobs views and would model these price ratios with significantly more price potential to the low side than the high side. We do believe that, ultimately, oil, oil products and natural gas prices/million Btu will return to relative levels that are close to the values seen during the 2005 to 2009 period.

- The calculation of System Heat Rates (SHRs) and their application to the forecast of Dracut gas prices to produce a forecast of energy prices at Newington after 2015 is an acceptable methodology.
- The use of lognormal histograms (price probability distributions) for setting the natural gas price distributions to start the SHR calculation is acceptable. The lognormal distribution parameters also appear to be reasonable.
- The blending of the NYMEX and SHR methods for 2015 is acceptable.

Model 3: Fuels Price Short Term and Long Term Stochastic Parameters Statistical Procedure

The mean reverting process that LAI uses as the basis of setting up their long term pricing scenarios appears reasonable to Jacobs Consultancy.[5] The elimination of the long run mean reversion rates is understood.

The derivation of the stochastic model parameters in this sub-model[6] appears to be reasonable. The use of daily granularity appears reasonable. The data sources that LAI used to build up their stochastic model parameters are standard sources and are thus reasonable.

Model 4: TOU Elasticity Parameters Statistical Procedures

LAI's approach to estimate seasonal elasticity parameters for use in the energy price estimate process appears to be quite reasonable.

Models 6 and 5: Energy Hourly Prices Historical Simulation model and Fuels Daily Prices Monte Carlo Simulation Model[7]

In general, LAI's approach to account for daily energy and fuel price uncertainty via a Monte Carlo stochastic simulation method appears to be acceptable.

- As noted earlier the approach used to estimate core energy prices from natural gas prices appears to be reasonable.
- The addition of an oil handling adders is expected.
- Switching to lower sulfur RFO in 2018 is realistic
- The set up of the Monte Carlo parameter sampling procedure is reasonable.

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[5] Jacobs Consultancy often uses similar versions of this process (variations of the Ornstein-Uhlenbeck mean reversion process and random walk processes) to model market forward prices in its asset valuation work. Based on energy price behavior over the past 25 to 30 years, Jacobs Consultancy often uses attenuated random walk processes versus mean reverting process for forecasting long-term energy price trends on stochastic models.

[6] That will be used in sub-model 5

[7] It is understood that sub-models 5 6 and 8 are controlled by MATLAB program code.

Model 7: Emission Allowance Pricing Model

In general, the basis for setting the emission allowances appears to be reasonable. Jacobs Consultancy might have added in an uncertainty factor for the CO_2 allowance price escalation rates, but, upon inspection this probably would not have made a material difference in the valuation results.

Model 8: Dispatch Simulation Model[8]

This relatively complex proprietary simulation model, with hourly granularity, which is the core program of the LAI model system and which works in conjunction with sub-models 5 and 6, appears, as an initial matter, to be set up in an acceptable manner, with one exception. This exception is as follows:

> LAI modeled energy net revenues on the assumption that Newington Station is dispatched only when it is economically profitable to do so, that is, when market-based revenues are expected to exceed fuel costs plus appropriate variable O&M costs including the cost of emission allowances. When this condition is met, the plant is assumed to be providing ISO-NE with profitable energy service. In reality, however, Newington Station also provides ISO-NE with operating reserves, which can result in the plant being dispatched at times when variable costs exceed market revenues (i.e., unprofitable operation). Therefore, LAI's modeling of energy production at Newington does not reflect actual operations, a fact that can result in differences between actual and expected outputs

In addition, because Jacobs has been given minimal insight into the details of this model's construction, we cannot be definitive on the reasonableness of its design. As a result, Jacobs has had to fall back upon a review of the model's performance in order to judge the reasonableness of its construction.

Although we cannot be definitive about its structure, the general concept of the model is familiar to Jacobs Consultancy and, aside from the exception noted above, it makes sense.[9] It appears to be appropriate for this type of system.

The modeling of forced outage events appears to be reasonable.

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[8] It is understood that sub-models 5, 6 and 8 are controlled by MATLAB program code.
[9] Jacobs Consultancy builds similar models (activity scanning models, process driven simulation models and event driven simulation models) for feedstock and products logistics systems, tank farms and complex supply chains.

Model 9: Capacity Price Scenarios Model

We will not comment on this sub-model as it was outside the scope of Jacobs Consultancy's work assignment.

Model 10: Financial Simulation Model

With one exception, the design of this sub-model appears to be straightforward and reasonable. The one exception is the lack of stochastic modeling of the uncertainty related to sustaining capital costs.[10]

Sustaining capital costs are clearly uncertain in the future, but it is Jacobs' experience that history and expectations regarding future regulatory changes and materials costs escalation rates can serve as an ample guide for a stochastic based estimate of these costs in the future.

It is Jacobs' opinion that if the model accounts for future uncertain values of energy and fuels it can also and should also account for future uncertain values of sustaining capital, based on both historical trends and expectations of potential deviation from historical trends (if any such expectations exist). If one model input is more uncertain than another the common solution for stochastic modeling is to model the more uncertain value with a wider input distribution, not to ignore it.

Overall Summary of Model System Structure

The LAI valuation model system is a complex valuation tool. If the model had been set up to account for the potential unprofitable supply of operating reserves, and if the correct data are entered into the model system, and if there are no programming or assumption errors in the model system, it should be able to deliver reasonable estimates of asset net present value.

Model Review Part 2: A Review of Model Function

This section comments on the model system (Model) results versus expectations derived from actual, recent performance data for Newington. It uses the model's results to make judgments regarding the reasonableness of the model.

[10] Jacobs Consultancy defines sustaining capital costs as, for example, the capital costs that are required to maintain plant equipment, replace plant equipment when a replacement makes more economic sense than an expensive repair, and upgrade plant equipment to meet new health, safety or environmental regulations.

Jacobs Consultancy's general approach to evaluating the reasonableness of asset value forecasting is as follows:

1. If projected future asset values based on net cash flow show a sudden material deviation from historical values or value trends, and these deviations cannot be explained by realistic (believable) changes in the business environment or by realistic (believable) changes in operating behavior, the valuation methodology is suspect.

2. Forecasts of asset values must account for all operating cost components and revenue components that contribute in a material way to the net cash flow from the asset.

3. Inflation treatment must be consistent and realistic.

Review of Initial Model Results

LAI's initial model results are summarized in Exhibit G.17 of Appendix G to *Public Service Company of New Hampshire Least Cost Integrated Resource Plan* dated September 30, 2010. The expected value of the energy net revenues[11] resulting from the model ranges from a low of $14.6 million in 2012 to a high of $20.6 million in 2020. This compares to actual energy net revenues from 2005 through 2010 of approximately $19.1, -$1.65, -$3.8, -$1.1, -$3.5 and $1.6 million.

The dramatic drop in actual energy net revenue from $19 million in 2005 to $1 million in 2010 was attributed to the significant increase in RFO prices over that time. The projected jump in energy net revenue from $1 million in 2010 period to $15.8 million in 2011, which is equally dramatic, could not be explained by LAI.[12] Nor could LAI adequately explain the generally upward trend in net revenues from 2011 to 2020[13] or the lack of negative net revenues during the 2011 to 2020 period. These unexplained results led Jacobs Consultancy to conclude that LAI's model is simulating something other than Newington Station's actual operations.

In order to test this conclusion, Jacobs Consultancy suggested a back-casting exercise, whereby the LAI would rerun the model beginning in 2010 instead of 2011 and that the model results for 2010 be compared with actual plant performance in that year. To conduct this exercise, the input data was generated in 2009 instead of 2010. The presumption was that if

[11] Energy Net Revenue = Energy Revenue – Fuel-related Expenses-Emission Allowance Expenses
[12] Answers to questions are recorded in formal responses. From Jacobs Consultancy's point of view this type of dramatic, sustained jump in performance should be explained by a reasonably plausible sustained change in business environment or management behavior or significant re-tooling of the facility.
[13] LAI's model did show a slight drop in net revenues, from 2011 to 2012, from $15.8 million to $14.6 million.

the model was a reasonable predictor of asset value it would generate operating results (including energy net revenue) that are reasonably close to actual 2010 performance.[14]

Analysis of Model after Major Program Error Corrections

Prior to conducting the back-casting exercise, LAI discovered multiple errors in the model, some relating to model design and some relating to the use of incorrect data inputs.

After correcting these errors, LAI filed on April 26, 2011 the document entitled *Appendix G Newington Station CUO Study Revisions, which summarized the results from rerunning the corrected model. The revised results* showed a much lower range of expected energy net revenues, varying from a low of $ 4.4 million in 2012 to a high of $7.6 million in 2020.

Although this was a substantial drop in energy net revenues, LAI still could not offer Jacobs Consultancy a reasonable explanation for the jump in net revenues from 2010 to 2011. As a result Jacobs remained unconvinced that the model offered a reasonable simulation of Newington Station's performance in the future. The back-cast exercise was still requested.

Review of Model After Back-Cast Exercise was Completed

The back-casting exercise revealed two additional errors with the model and one problem with the 2010 results for the plant. The modeling errors related to the underestimation of start-up fuel costs and the failure to include the cost 2FO to keep the boiler from freezing during the winter months. After correcting these errors and adjusting the emission allowance costs in the 2010 data, the difference between simulated and actual 2010 energy net revenues was still $1.1 million or 45%, an uncomfortably large percentage. Table 2 summarizes the results of the back-cast analysis.

[14] It would generate energy net revenue reasonably close to the result for 2010. (An exact match would not be expected.)

Table 2
Back-Cast Result Analysis

$000	Rev 0	Rev 1	Rev 2	Rev 1	Rev 0
	Original Actual 2010	Actual with estimated actual emissions costs versus accounting emissions allowance costs	Additional change to include additional start-up fuel	Backcast corrected to include $1.2 million in plant warming costs	**Original Backcast**
Energy Revenue	22,829	22,829	22,640	24,502	24,502
Fuel Cost	(19,787)	(19,787)	(17,338)	(18,787)	(18,787)
Emission Allowance Cost	(1,969)	(428)	(328)	(356)	(356)
Plant warming cost	included	included	(1,200)	(1,200)	(0)
Net Revenue ($000)	1,073	**2,614**	**3,774**	4,159	5,359
		delta	1,160		

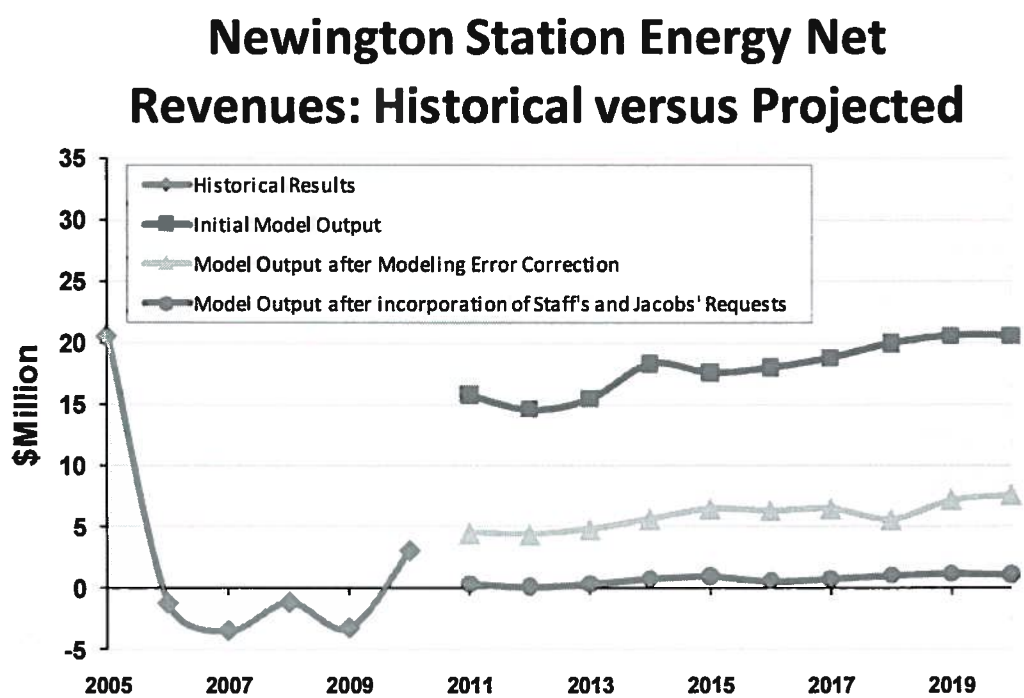
Review of Model After Final Run Incorporating Staff's and Jacobs Desired Changes.

Following the analysis of the back-cast results, Staff and Jacobs requested LAI to rerun the model with the following changes.

1. Incorporate the additional start-up costs in the model.
2. Incorporate the plant warming costs in the model.
3. Incorporate the RFO/natural gas and 2FO/natural gas price ratios noted in Table 1 in the LAI model.
4. Incorporate in the model the basis differentials derived from the 2010 invoices submitted by the natural gas supplier to Newington Station.

The model was re-run and energy net revenues during the 2011 to 2010 period fell to the $0.15 Million to $1.2 million range. Jacobs Consultancy views these values as more realistic. Jacobs' opinion is that if the LAI model is run with the above 4 modifications it will develop an NPV forecast for the asset over the 10 year forecast period that is more realistic. Fi gure 2 summarizes the changes in net revues during each phase of the model "correction" process.

Figure 2



Overall Conclusions

- The LAI valuation model is a complex tool. If the model was set up to account for the potential delivery of unprofitable supply of operating reserves, if the correct data are entered into the model system and if there are no errors in the model system it should be able to deliver reasonable estimates of asset net present value.

- Since Jacobs Consultancy was not allowed to review and perform in-depth testing of the actual LAI model and its sub-units we cannot definitively comment on the integrity of the model structure. We cannot say that based on its structure it is or it is not likely to produce a realistic estimate of asset value, nor can we say that it is or it is not likely to be free of material flaws.

- On the basis of structural model errors discovered during the course of Jacobs' review, it has been shown that the model originally contained errors. Jacobs cannot definitively state as to whether the model has other errors.

- If we assume that the model is free of structural flaws, it is Jacobs's opinion that it can be used as a reasonable approximate predictor of Newington Station financial performance if the following changes are incorporated into the model:

- Set it up to account for the potential delivery of unprofitable operating reserves
- Modify the model to account for realistic start-up fuel costs
- Modify the model to account for realistic plant warming costs
- Use basis differentials that underlie Newington Station's delivered natural gas prices for 2010
- Account for uncertainty in sustaining capital costs

- Regarding accounting for uncertainty in sustaining capital costs, it is Jacobs' opinion that if the model accounts for future uncertain values of energy and fuels it can also and should also account for future uncertain values of sustaining capital, based on both historical trends and expectations of potential deviation from historical trends (if any such expectations exist). If one model input is more uncertain than another a common solution for stochastic modeling is to model the more uncertain value with a wider input distribution, not to ignore it.

Public Service Company of New Hampshire
Docket No. DE 10-261

Technical Session TS-02

Dated: 06/22/2011
Q-TECH-007
Page 1 of 4

Witness: **Richard L. Levitan**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Re-run the Levitan Newington CUO Study model with the following data input changes:

a) Apply a premium to the Dracut natural gas price of 80 cents in Jan-Feb and 84 cents in all other months.
b) Include the revision to the start up costs to reflect adjustment made by Levitan in 2010 Backcast analysis.
c) Change the natural gas/ #6 residual oil parity ratio to reflect oil being 4.0 times higher than natural gas in 2011 and narrowing down on a linear basis to 3.5 times higher than natural gas in 2020. Also adjust #2 fuel oil parity ratio to reflect oil being 5.0 times higher than natural gas in 2011 and narrowing down on a linear basis to 4.5 times higher than natural gas in 2020.
d) Add warming fuel as a separate line item in the financial result when reporting the final results.

Response:
Implementation details of the data input changes in the requested model run are as follows:

a) As in the CUO Study run, the Dracut premium inputs are in 2010 dollars and escalated at 2.4% annually over the 2011 to 2020 period.

b) As in the 2010 Backcast run with higher start costs, no energy generation or revenue was credited for dispatch while ramping from the 20 MW online load to the 60 MW stable minimum operating load.

c) RFO prices don't vary by month and 2FO prices have very little seasonal shape, so the requested oil to gas price ratios were applied to annual average natural gas prices at Dracut. The RFO oil to gas price ratios were applied to both 1% S RFO, used through 2017, and 0.5% S RFO, used from 2018 to 2020.

d) Annual warming fuel of 72.9 BBtu of 2FO, per the calculation reported in TS-02, Q-TECH-006(b), was multiplied by the annual average 2FO prices for the respective scenarios and years. Warming fuel is fired in the auxiliary boilers. Almost all modeled emission allowance costs are for CO2 allowances, which are only required for the main boiler, so no additional emission allowance costs were calculated.

Expected value revenue requirements results are presented in Attachment 1, in the same basic format as Exhibit G.12, with the addition of "Warming" and "Operation" sub items under "Fuel and Fuel Related O&M" expenses. The PV of net revenue requirements is still a negative number, indicating that continued operation of Newington Station is expected to produce customer benefits.

Operational performance results are presented in Attachment 2, in the same basic format as Exhibit G.17 of the CUO Study, with additional row items under the "With Warming Fuel" heading in each of the three panels (for expected value, median, and P25 results). Warming fuel is modeled as a constant 72.9 BBtu, regardless of how much the plant ran during the winter. The warming cost is the 72.9 BBtu times the price of the 2FO for the scenario (or all scenarios for the expected value panel). The warming fuel cost is added as an after-the-fact adjustment to the financial results reported by the model.

A complication resulting from insufficient time to include the warming fuel costs within the dispatch model is that the percentile-based results in the P50 and P25 panels are reported on the basis of energy net revenue without warming cost. This means that because the warming costs were added outside the model, the bottom line net revenue results, with warming costs, do not represent the indicated percentile levels. For example, in 2011, the P50 net revenue with warming cost included is smaller (more negative) than the P25 result. If the percentile results were ranked with the warming fuel costs included, the P50 and P25 cases would vary slightly. Also, the year-to-year fluctuations in the net revenue results with warming cost are larger than if that measure had been used for the percentile ranking since the (e.g.) P25 scenario, without inclusion of warming costs in the net revenue ranking, may in one year have high 2FO prices, but the P25 scenario for the next year may have low 2FO prices, resulting in overly wide warming cost fluctuation.

Attachment 1

Expected Values of Incremental Revenue Requirements
Case: Higher Start Cost and Warming Fuel Cost; PUC Staff Requested Natural Gas Premiums and Oil Prices

	Present Value EOY	Calendar Year 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expenses ($000)											
Non-Fuel O&M with Indirects											
Other than Emission Allowances	$57,236	$7,498	$7,706	$7,920	$8,139	$8,366	$8,600	$8,841	$9,089	$9,343	$9,605
Emission Allowances	$1,415	$179	$170	$181	$212	$225	$207	$212	$243	$244	$248
Total O&M Expense	$58,651	$7,677	$7,876	$8,101	$8,351	$8,591	$8,807	$9,053	$9,331	$9,587	$9,853
Fuel and Fuel Related O&M	$98,035	$10,981	$11,772	$12,875	$14,954	$15,926	$15,019	$15,476	$16,923	$16,709	$16,756
Warming		$1,885	$2,133	$2,263	$2,332	$2,389	$2,431	$2,450	$2,457	$2,455	$2,463
Operation		$9,096	$9,639	$10,612	$12,622	$13,537	$12,589	$13,025	$14,466	$14,253	$14,293
Property Tax	$9,057	$958	$1,034	$1,117	$1,206	$1,303	$1,407	$1,520	$1,641	$1,773	$1,914
Depreciation Expense	$2,879	$50	$106	$168	$240	$323	$423	$548	$715	$965	$1,465
Total Expenses	$168,621	$19,666	$20,789	$22,261	$24,751	$26,142	$25,656	$26,596	$28,610	$29,033	$29,988
Rate Base ($000)											
Incremental Gross Plant Value		$500	$1,000	$1,500	$2,000	$2,500	$3,000	$3,500	$4,000	$4,500	$5,000
Incremental Accum. Depreciation		$50	$156	$324	$563	$886	$1,309	$1,857	$2,571	$3,536	$5,000
Net Plant Value		$450	$844	$1,176	$1,437	$1,614	$1,691	$1,643	$1,429	$964	($0)
Working Capital		$925	$925	$925	$925	$925	$925	$925	$925	$925	$925
Accumulated Deferred Taxes		$12	$32	$64	$112	$181	$279	$417	$613	$898	$1,372
Fuel Inventory (year end)		$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
NOx, SO2, CO2 Allowance Inventory		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Material & Supply Inventory		$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500	$2,500
Total Rate Base		$13,887	$14,301	$14,665	$14,973	$15,219	$15,395	$15,485	$15,466	$15,287	$14,796
Average Return on Rate Base		*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*	*11.09%*
Return on Rate Base ($000)	$11,271	$1,540	$1,586	$1,626	$1,660	$1,688	$1,707	$1,717	$1,715	$1,695	$1,641
Expenses Plus Return on Rate Base	$179,892	$21,206	$22,374	$23,887	$26,411	$27,830	$27,363	$28,313	$30,325	$30,728	$31,628
Revenues ($000)											
Energy	$104,104	$11,549	$12,088	$13,431	$15,958	$17,116	$15,813	$16,483	$18,216	$18,172	$18,114
Capacity	$111,205	$17,250	$13,343	$12,121	$12,779	$13,791	$14,903	$16,420	$17,830	$22,106	$29,026
Ancillary	$1,367	$200	$200	$200	$200	$200	$200	$200	$200	$200	$200
10 MW Unitil Entitlement	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Revenue	$216,676	$28,999	$25,631	$25,752	$28,937	$31,107	$30,916	$33,103	$36,246	$40,477	$47,340
NET REVENUE REQUIREMENT	($36,785)	($7,793)	($3,257)	($1,864)	($2,526)	($3,277)	($3,553)	($4,789)	($5,921)	($9,749)	($15,712)

Public Service Company of New Hampshire
Docket No. DE 10-261

Technical Session TS-02
Dated: 06/22/2011
Q-TECH-007
Page 4 of 4

Attachment 2

Operational Performance at Selected Annual Energy Net Revenue Probability Levels
Case: Higher Start Cost and Warming Fuel Cost; PUC Staff Requested Natural Gas Premiums and Oil Prices

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Expected Value										
DAM Dispatch Hours	451	429	445	508	525	470	471	526	514	506
RT Dispatch Hours	19	17	17	22	23	21	22	23	25	26
Generation (GWh)	137.0	130.0	134.7	154.3	159.9	143.1	143.5	160.2	157.2	155.6
Number of Starts	22	22	22	25	24	22	22	23	23	23
2FO Consumption (BBtu)	13	13	13	15	15	14	14	15	15	14
RFO Consumption (BBtu)	3	3	2	2	3	4	4	5	9	19
Gas Consumption (BBtu)	1,544	1,468	1,521	1,743	1,805	1,616	1,619	1,806	1,768	1,740
CO2 Emitted (1000 ton)	92	87	90	103	107	96	96	107	105	105
SO2 Emitted (ton)	15	14	15	17	17	16	16	16	17	19
NOx Emitted (ton)	92	87	91	104	107	96	97	108	106	105
Capacity Factor (%)	3.9%	3.7%	3.8%	4.4%	4.6%	4.1%	4.1%	4.6%	4.5%	4.4%
Service Factor (%)	5.4%	5.1%	5.3%	6.0%	6.3%	5.6%	5.6%	6.3%	6.2%	6.1%
Energy Revenue ($1000)	11,549	12,088	13,431	15,958	17,116	15,813	16,483	18,216	18,172	18,114
Energy Cost ($1000)	9,276	9,809	10,793	12,834	13,762	12,795	13,237	14,708	14,498	14,541
Net Revenue ($1000)	2,273	2,279	2,638	3,124	3,354	3,018	3,245	3,508	3,674	3,573
With Warming Fuel										
2FO Consumption for Warming Use (BBtu)	73	73	73	73	73	73	73	73	73	73
Warming Cost ($1000)	1,885	2,133	2,263	2,332	2,389	2,431	2,450	2,457	2,455	2,463
Energy Cost with Warming Fuel ($1000)	11,160	11,943	13,056	15,166	16,150	15,226	15,688	17,166	16,953	17,004
Net Revenue with Warming Fuel ($1000)	389	146	375	792	965	587	795	1,050	1,219	1,110
P50 (Median)										
DAM Dispatch Hours	287	328	328	756	595	389	537	469	604	545
RT Dispatch Hours	5	13	5	48	21	16	6	29	31	36
Generation (GWh)	85	97	97	234	183	116	158	144	186	166
Number of Starts	12	22	21	39	19	25	23	20	25	34
2FO Consumption (BBtu)	9	14	11	23	13	15	15	13	14	19
RFO Consumption (BBtu)	0	0	0	0	3	14	0	0	1	0
Gas Consumption (BBtu)	972	1,113	1,099	2,629	2,018	1,318	1,785	1,626	2,091	1,875
CO2 Emitted (1000 ton)	58	66	65	156	119	80	106	96	124	111
SO2 Emitted (ton)	6	13	13	27	12	22	16	13	15	20
NOx Emitted (ton)	58	66	65	156	121	80	106	96	124	111
Capacity Factor (%)	2.4%	2.8%	2.8%	6.7%	5.2%	3.3%	4.5%	4.1%	5.3%	4.7%
Service Factor (%)	3.3%	3.9%	3.8%	9.2%	7.0%	4.6%	6.2%	5.7%	7.2%	6.6%
Energy Revenue ($1000)	8,817	10,148	13,959	19,980	14,369	13,263	14,220	11,801	15,383	23,460
Energy Cost ($1000)	6,718	8,208	11,804	17,172	11,544	10,731	11,735	8,800	12,535	20,466
Net Revenue ($1000)	2,099	1,940	2,155	2,808	2,825	2,531	2,485	3,001	2,848	2,994
With Warming Fuel										
2FO Consumption for Warming Use (BBtu)	73	73	73	73	73	73	73	73	73	73
Warming Cost ($1000)	2,306	2,207	3,479	2,500	1,228	2,223	1,092	1,754	1,397	3,736
Energy Cost with Warming Fuel ($1000)	9,023	10,415	15,283	19,672	12,772	12,954	12,826	10,554	13,932	24,202
Net Revenue with Warming Fuel ($1000)	-206	-267	-1,324	308	1,597	309	1,394	1,247	1,450	-742
P25										
DAM Dispatch Hours	391	311	294	489	302	481	600	502	477	512
RT Dispatch Hours	24	15	23	34	24	16	30	30	23	40
Generation (GWh)	120.7	95.8	90.8	149.3	94.5	145.6	181.2	157.8	145.0	159.6
Number of Starts	22	21	17	22	22	14	38	14	29	20
2FO Consumption (BBtu)	14	11	11	15	13	9	21	11	18	12
RFO Consumption (BBtu)	15	12	0	0	12	0	0	4	11	0
Gas Consumption (BBtu)	1,360	1,074	1,025	1,692	1,068	1,633	2,059	1,767	1,644	1,787
CO2 Emitted (1000 ton)	82	65	61	100	65	96	122	105	98	105
SO2 Emitted (ton)	21	19	11	15	18	9	23	9	21	13
NOx Emitted (ton)	82	66	60	100	65	97	122	105	99	106
Capacity Factor (%)	3.4%	2.7%	2.6%	4.3%	2.7%	4.2%	5.2%	4.5%	4.1%	4.6%
Service Factor (%)	4.7%	3.7%	3.6%	6.0%	3.7%	5.7%	7.2%	6.1%	5.7%	6.3%
Energy Revenue ($1000)	9,037	8,501	7,881	9,767	9,429	9,965	10,329	9,643	16,023	10,242
Energy Cost ($1000)	7,695	7,247	6,439	7,903	7,801	8,210	8,912	7,721	14,167	8,460
Net Revenue ($1000)	1,343	1,253	1,443	1,864	1,627	1,755	1,417	1,921	1,856	1,782
With Warming Fuel										
2FO Consumption for Warming Use (BBtu)	73	73	73	73	73	73	73	73	73	73
Warming Cost ($1000)	1,495	2,221	1,840	1,612	2,171	1,563	1,163	1,428	1,666	1,300
Energy Cost with Warming Fuel ($1000)	9,189	9,468	8,279	9,515	9,972	9,773	10,076	9,149	15,833	9,760
Net Revenue with Warming Fuel ($1000)	-152	-967	-397	252	-544	192	253	494	190	482

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-042
Page 1 of 1

Witness: **William H. Smagula,Elizabeth H. Tillotson**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Does PSNH expect Newington Station to undergo significant refurbishment, upgrade or replacement within the five-year planning period whether to improve or maintain plant performance, meet existing or new environmental regulations, or maintain plant availability? If so, please provide details including the expected cost of such measures, timing and nature of the cost incurrence.

Response:
No, PSNH has no current plan for Newington Station to undergo significant refurbishment, upgrade or replacement within the five-year planning period.

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-01

Dated: 03/04/2011
Q-STAFF-057
Page 1 of 1

Witness: **William H. Smagula,Elizabeth H. Tillotson**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Please provide the capital additions and retirements for Newington Station for each year during the six-year period ending December 31, 2010.

Response:
Attached is the capital additions and retirements for Newington Station for each year during the six-year period ending December 31, 2010.

Year	Additions	Retirements
2005	5,966,218.64	1,117,492.89
2006	1,045,824.55	694,640.43
2007	1,717,643.94	511,274.41
2008	2,653,165.11	255,325.28
2009	895,949.10	533,045.08
2010	109,893.84	229,167.88

Public Service Company of New Hampshire
Docket No. DE 10-261

Data Request STAFF-02

Dated: 04/29/2011
Q-STAFF-009
Page 1 of 1

Witness: **William H. Smagula**
Request from: **New Hampshire Public Utilities Commission Staff**

Question:
Follow-up to Technical Session. Please explain the basis of the Company's belief that the EPA's new environmental rule on mercury, non-mercury metals, and acid gas emissions will not impose compliance costs on Newington Station that exceed the assumed $0.5 million annual amount through 2020.

Response:
During the Technical Session, environmental compliance costs at Newington Station were discussed a couple of times along with the station's current levelized capital budget projection estimates. When the topic was revisited, with an inquiry along the lines of the above, the company clearly withdrew possible misconstrued comments and clarified that at this point in time, without a final rule issued and a compliance period that will likely be in 2015 or later, specific compliance costs are not known.