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STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DG 06-105

In the Matter of:
EnergyNorth Natural Gas, Inc.
2006 Integrated Resource Plan

Direct Testimony

of

George R. McCluskey
Utility Analyst

REDACTED VERSION

February 7, 2007

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc)
2006 Integrated Resource Plan)

Docket No. DG 06-105

DIRECT TESTIMONY
OF
GEORGE R. McCLUSKEY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is George McCluskey, and my business address is the New Hampshire Public Utilities Commission ("Commission"), 21 South Fruit Street, Suite 10, Concord, NH 03301.

Q. WHAT IS YOUR POSITION WITH THE COMMISSION?

A. I am an Analyst within the Electricity Division. I also assist the staff of the Gas & Water Division on gas-related policy issues.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I am a utility ratemaking specialist with over 20 years experience in utility economics. I rejoined the Commission in March 2005 after working as a consultant for LaCapra Associates for five years. Before joining LaCapra, I directed the Commission's electric utility restructuring division 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. I have participated in restructuring-related activities in New Hampshire, Arkansas, Pennsylvania, California and Ohio and have presented or filed testimony before state regulatory authorities in New Hampshire, Maine, Ohio and Arkansas and before the FERC. A copy of my resume is included as Exhibit GRM-1 to this testimony.

Q. PLEASE STATE THE PURPOSE OF YOUR TESTIMONY.

A. The purpose of my testimony is to present the Staff's position on whether, as discussed in EnergyNorth Natural Gas, Inc.'s ("ENGI or Company") 2006 Integrated Resource Plan ("IRP"), ENGI's planning processes are adequate and whether the IRP addresses the IRP-related issues set forth in the Settlement Agreement approved in Order No. 24,531 (2005). My testimony concludes that the IRP addresses the issues required in Order No. 24,531. However, it also concludes, among other things, that the Company does not have a formal plan to meet at least cost the projected incremental increase in customer demand over the planning period.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. I begin in Section II with a discussion of the standards for the review and approval of natural gas company IRP filings. This is followed in Section III with my comments on ENGI's proposed design day and design year planning standards. In Sections IV and V, I address the assessments of demand-side and supply-side resources respectively. Also, I address, in Section V, whether it is appropriate for the Company to establish a capacity reserve to protect customers against the risks associated with grandfathered transportation customers returning to firm sales service. Finally, Section VI addresses the integration of demand- and supply-side resources.

Q. BEFORE YOU BEGIN YOUR DISCUSSION OF THE STANDARDS FOR REVIEW AND APPROVAL OF INTEGRATED RESOURCE PLANS, PLEASE SUMMARIZE STAFF'S CONCLUSIONS.

A. Staff's conclusions are summarized as follows:

(1) The cost/benefit analysis supporting the proposed design day and design year planning produces more questions than answers, potentially resulting in unnecessary costs for consumers.

(2) Least-cost planning is the systematic assessment of all reasonably available demand-side and supply-side resource options to satisfy customer requirements at the lowest cost consistent with reliable supply. The IRP, however, includes virtually no discussion, much less evaluation, of the available supply- and demand-side resource options to meet customer requirements over the planning period. In fact, the demand-side assessment was completely omitted.

(3) The IRP neither discusses the process for integrating cost effective demand-side and supply-side resources nor identifies the preferred portfolio of

existing and new resources that satisfies forecasted loads at least cost over the planning period.

(4) The Company's recommendation that the level of any capacity reserve authorized by the Commission be set at 100% of grandfathered customer demands is not supported by evidence that firm sales customers would benefit from such a reserve.

In view of these conclusions, Staff recommends that the Commission: (i) find the IRP not adequate; and (ii) direct the Company to implement the changes recommended in the remainder of this testimony.

II. STANDARDS FOR REVIEW

Q. WHAT STANDARDS HAVE YOU APPLIED TO ASSESS WHETHER THE COMPANY'S IRP IS ADEQUATE?

A. Since there are no explicit standards for New Hampshire natural gas company integrated resource plans, I have based my review of the IRP on the relevant portions of the statute that applies to electric utility least cost integrated resource plans: namely, RSA 378:38. This statute specifies, in relevant part, that each electric utility least cost integrated resource plan must include the following reports:

1. A forecast of future electrical demand for the utility's service area;

2. An assessment of the demand-side energy management programs, including conservation, efficiency improvement, and load management programs;

3. An assessment of supply-side options;

5. Provision of diversity of supply sources; and

6. Integration of demand-side and supply-side options.

I n my opinion, these basic building blocks of an electric utility least cost integrated resource plan would be the building blocks of an integrated resource plan for a natural gas company.

Q. HAS THE COMMISSION SPECIFIED THE CRITERIA THAT IT WOULD USE TO DETERMINE WHETHER AN ELECTRIC UTILITY LEAST COST INTERGRATED RESOURCE PLAN IS ADEQUATE?

A. Yes, it has. In *Granite State Electric Co*., 74 NH PUC 325 (1989) (Order No. 19,546), the Commission stated that it would use the following criteria to evaluate the adequacy of a utility's planning process:

1. Completeness in meeting the reporting requirements;
2. Comprehensiveness in identifying and assessing all resource options, both on the demand-side and the supply-side;
3. Integration of the planning process, i.e., evaluating demand- and supply-side options in an equivalent manner and addressing issues of coordinated timing in the acquisition of resources;
4. Feasibility of implementing the least cost resource plan; and

5. Adequacy of the planning process, i.e., providing for resources in a timely manner sufficient to meet the electricity and energy service needs of utility customers both now and for the future.

Q. DID THE COMMISSION RECENTLY AFFIRM THE CRITERIA SET FORTH IN ORDER NO. 19,546?

A. Yes, in Order No. 24,695, the Commission effectively upheld the 1989 criteria.

Q. IN YOUR OPINION, DOES THE IRP SATISFY THE ABOVE DESCRIBED BASIC REQUIREMENTS?

A. No, the filing is deficient in several important respects. Based on the relevant portions of RSA 378:38, and the criteria established in Order 19,546, I have concluded that the resource planning process described in the IRP fails to meet the standard of adequacy. The reasons underlying this conclusion are set forth in the following sections.

III. DEMAND FORECAST – PLANNING STANDARDS

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S DEMAND FORECASTING PROCESS.

A. The Company used econometric models to forecast customer requirements under normalized weather conditions in its traditional markets.[1] Specifically, the Company forecasted incremental demand above the level established for the

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[1] Incremental demand forecasts for non-traditional markets, such as natural gas vehicles and large scale power generation, were developed separately.

IRP's reference year, which was 2005/06. Forecasts of incremental demand for traditional and non-traditional markets were then summed and the total reduced by the expected savings from DSM.

In addition, ENGI forecasted peak day and annual gas demands under design day and design year weather conditions in order to guide the planning of a resource portfolio that is capable of meeting customer demands reliably at least cost under abnormal weather conditions. Design day demand is the gas demand on the peak day when the weather conditions, expressed in Effective Degree Days (EDD), equal the adopted peak day planning standard. Design year demand is the annual gas demand in a year in which the weather conditions, expressed in EDD, equal the approved annual planning standard.

Q. PLEASE SUMMARIZE THE NORMALIZED FORECASTS OF CUSTOMER REQUIREMENTS.

A. The compound annual growth rate under the base case scenario is estimated at 2.05 percent. In comparison, the compound annual growth rates under the high case and low case scenarios are 2.79 percent and 1.36 percent respectively.

Q. WHAT PLANNING STANDARDS IS THE COMPANY PROPOSING?

A. The Company has proposed a design year planning standard of 7,680 EDD with a probability of occurrence of once in 47.32 years and a design day planning standard of 80.2 EDD with a probability of once in 42.49 years.

Q. DOES STAFF SUPPORT THESE PLANNING STANDARDS?

A. No, for the reasons presented below.

Q. PLEASE EXPLAIN THE PROCESSES USED TO DETERMINE THE COMPANY'S PLANNING STANDARDS STARTING WITH THE DESIGN DAY.

A. In summary, the Company established its design day standard using a three-step process. First, it performed a statistical analysis of the coldest days derived from a Monte Carlo simulation. Second, it conducted a cost-benefit analysis to evaluate the cost of acquiring additional resources to meet peak demands versus the cost to customers of experiencing service curtailments. Third, it identified a design-day standard where the incremental cost of acquiring the resources equals the incremental benefit of not curtailing demand.

Q. IS THE ABOVE DESCRIBED PROCESS CONSISTENT WITH THE RECOMMENDATIONS OF STAFF'S CONSULTANT, LIBERTY CONSULTING GROUP, IN DOCKET DG 04-133?

A. Yes and no. In a report entitled "Final Report - Review of Supply Planning and Asset Management Agreements of EnergyNorth Natural Gas, Inc."[2] Liberty determined that the Company's time series of coldest days for each year over the period 1981 through 2000 was not normally distributed and hence a design day standard set equal to the mean plus two standard deviations would not necessarily capture 95 percent of the possible outcomes for weather in ENGI's service

[2] The report was presented to the Commission on August 12, 2005.

territory. In order to rectify this problem, Liberty recommended that the Company: (i) employ Monte Carlo simulation to develop a probability distribution for ENGI's weather; and (ii) base its design day standard on a statistical analysis of that distribution. In response to this recommendation, the Company revised its statistical analysis to incorporate Monte Carlo simulation but chose not to follow the recommendation to discontinue use of the cost/benefit analysis.

Q. HOW DOES MONTE CARLO SIMULATION WORK?

A. Monte Carlo simulation assumes that weather temperature follows a continuous distribution with an infinite range. As a result, there is always a probability that a new observation (e.g., the temperature on the coldest day of a year) will fall above or below what has been historically observed. A Monte Carlo simulation is used to generate a probability distribution representative of the full distribution, including the unobserved "tails" that would otherwise be ignored by basing decisions on historical observations alone. Monte Carlo simulation thus allows accurate modeling of the extremes of the distribution.

Q. IN ITS MONTE CARLO SIMULATION, HOW LONG IS THE TIME SERIES OF DAILY EDD AND WHAT RESULTS DID THE SIMULATION PRODUCE?

A. The Company used a synthetic dataset of 3,000 years, which resulted in a mean value of 66.98 EDD for the peak day with a standard deviation of 5.99 EDD.[3] If a design-day standard equal to two standard deviations away from the mean had been chosen, the standard would have been 66.98+(5.99*2) = 78.96 EDD or 79 EDD after rounding. This, however, is 1.2 EDD lower than the standard actually proposed by the Company, or 80.2 EDD.[4] Though not large in absolute terms, the difference is important because, from a probabilistic standpoint, a 79 EDD design day occurs once in every 32.26 years whereas an 80.2 EDD design day occurs once in every 46.69 years.[5] In short, the Company's proposed standard would require more resources than the standard resulting from statistical analysis alone and, hence, would be more costly to consumers.

Q. WOULD A ONE IN 32 YEAR DESIGN DAY STANDARD EXPOSE CUSTOMERS TO UNREASONABLE SUPPLY RISKS?

A. We do not believe so. Northern Utilities, Inc.'s ("Northern") 2006 IRP proposes to revise its design day standard to a 1 in 33 year probability of occurrence, reflecting a small change from the current 1 in 25 year standard. Northern states that the revised design day criteria is: (i) appropriate in view of the limited pipeline interconnections and overall lack of liquidity in the region; and (ii) more consistent with those used by other LDCs in the region.

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[3] IRP, Section III.C.1,f.

[4] IRP, Chart III-E-2.

[5] IRP, Section III.C.1,f, page xx.

In addition, a 1 in 30 year design day standard was used by ENGI in its last IRP prior to being acquired by KeySpan. Further, Staff is unaware of any interruption in service by either Northern or ENGI as a result of using 1 in 25 year or 1 in 30 year design day planning standards.

Q. WHY DID LIBERTY RECOMMEND AGAINST USING A COST/BENEFIT ANALYSIS IN THE DEVELOPMENT OF THE DESIGN DAY STANDARD?

A. Liberty explained that the goal of the cost/benefit analysis was to determine the point where the cost of incremental supply just equals the benefit of avoiding curtailment for an average customer, with both the costs and benefits developed as ranges. On the benefit side, the range extended from a relatively low benefit that included a low proportion of residential customers whose homes would be damaged by curtailment to a relatively high benefit that reflected a high proportion of residential customers affected by curtailment. On the cost side, the range extended from a low-cost supply option – propane vaporization capacity – to a high-cost supply option – interstate pipeline capacity. Liberty's concern with this analysis was that the Company would not, in practice, curtail average customers. Rather, it would curtail low priority customers consistent with the Company's tariff. Thus, the benefit of avoiding curtailment under the Company's cost/benefit analysis would likely overstate the actual benefits, potentially resulting in a higher than necessary design day standard.

Q. DOES STAFF SHARE LIBERTY'S CONCERN?

A. Staff's concern with the cost/benefit analysis runs much deeper than deciding whether the benefits of increased reliability should be based on the curtailment of average or low priority customers. In Staff's opinion, the curtailment or outage costs avoided by increasing the design day standard are comprised of the following:

1. The loss in consumer surplus[6]
2. Cost of re-lights
3. Lost revenue

While the Company's analysis covered the first two components,[7] the consumer surplus estimates leave a lot to be desired. Although the Company admits to some uncertainty as to what might occur in the event of curtailment of residential customers, its damage estimates were not supported by meaningful market research into the value that residential customers place on reliability. Nor were the Company's damage estimates for C&I customers supported by market research into the value of lost production.

Staff's greatest concern, however, is with the Company's estimates for the incremental cost of increasing the level of reliability, which as noted above was represented by the difference in cost between installing a LP-air facility and adding additional interstate pipeline capacity. Since each increase in the design day planning standard should be matched with a corresponding change in the portfolio to optimize costs, the cost of reliability should be the combined cost of

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[6] Consumer surplus refers to the value that firm customers lose in the event of curtailment.
[7] Lost revenues were excluded because the Company apparently does not seek to recoup such losses.

the resources that make up the optimal portfolio plus the dispatch costs.[8] In other words, to estimate accurately the cost of varying the level of reliability, the Company should have used its SENDOUT model to estimate the levelized portfolio cost associated with each level of reliability. From this stream of levelized costs, the Company would then calculate a stream of incremental costs by subtracting the levelized portfolio cost associated with one level of reliability from the levelized portfolio cost associated with the next level. Comparing the stream of increment costs with the stream of incremental benefits would reveal whether the proposed increase in the design day standard from 79 EDD to 80 EDD would be cost effective.

Q. GIVEN THIS CRITIQUE OF THE COMPANY'S COST/BENEFIT ANALYSIS, WHAT DOES STAFF RECOMMEND?

A. Staff recommends that the Commission direct the Company to use, in its next IRP, the method described above to analyze the costs and benefits of changing its design day standard. Pending the outcome of that analysis, Staff recommends that planning be conducted based on a design day standard of 79 EDD.

Q. PLEASE EXPLAIN THE PROCESS USED TO DETERMINE THE DESIGN YEAR STANDARD.

A. The Company also used a three-step process to select its design year standard. The only differences between this process and the process used to determine the design day standard are that: (a) the statistical analysis is of annual EDD data, and

[8] See, for example, the 2005 Least Cost Plan of Puget Sound Energy

(b) the cost/benefit analysis focuses on the number of days supply is short and the quantity of the shortfall.

Q. WHAT WAS THE RESULT OF THE MONTE CARLO SIMULATION?

A. For each of the 3,000 synthetic years, the Company calculated the annual EDD. This dataset resulted in a mean value of 7,079 EDD with a standard deviation of 291.29 EDD.[9] If a design year standard equal to two standard deviations away from the mean had been chosen, the standard would have been 7,079+(291.29*2) = 7,660 EDD rounded. While this is only 18 EDD lower than the 7,680 EDD design year standard proposed by the Company,[10] Staff estimates the cost to customers of meeting that higher standard could be significant since a 7,660 EDD design year occurs once in every 33 years whereas a 7,680 EDD design year occurs once in every 47 years.

Q. DOES STAFF RECOMMEND THAT THE LOWER DESIGN YEAR STANDARD BE ADOPTED?

A. Yes, for the same reasons used to support our recommendation relating to the design day standard, Staff recommends that the Company be directed to conduct, in its next IRP, a more detailed analysis of the benefits and costs of increasing the design year standard. In the meantime, we recommend adoption of a 7,660 EDD design year standard.

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[9] IRP, Section III.C.1,g.

[10] IRP, Chart III-E-2.

IV. ASSESSMENT OF DEMAND-SIDE PROGRAMS

Q. DOES THE IRP INCLUDE AN ASSESSMENT OF DEMAND-SIDE RESOURCES?

A. No, it does not.

Q. HOW, IF AT ALL, DOES THE IRP ADDRESS DEMAND-SIDE RESOURCES?

A. Energy efficiency savings associated with Commission-approved demand-side programs, the most recent of which were approved in Order No. 24,636 (Docket DG 06-032)[11], are deducted from the Company's demand forecast. However, because the cost-effectiveness of these programs was determined based on New England-wide avoided supply costs rather than ENGI-specific avoided supply costs, it is unclear whether: (i) the approved programs are cost-effective relative to ENGI supply-side alternatives; and (ii) the quantity of approved programs is optimal.

Q. WHAT DOES STAFF RECOMMEND?

A. As a first step, the Company in its next IRP should identify and describe all reasonably available demand-side programs and present estimates of the associated lifetime savings and related implementation costs. Technical and market potentials should also be provided. Technical potential represents the total savings associated with the installation of all feasible measures, including the effects of the existing stock of demand-side measures. Market potential is the

[11] These programs cover the period May 1, 2006 through April 30, 2009.

portion of the technical potential that could reasonably be accessed through the use of utility programs. The market potential would then be apportioned into several blocks representing different marketing intensity levels. ENGI should then use scenario analysis to model the costs and benefits of varying levels of activity before selecting the scenario which best meets the planning criteria. The process used to determine the costs and benefits of these resource blocks should be fully explained.

V. ASSESSMENT OF SUPPLY-SIDE OPTIONS

Q. IS THE COMPANY'S SUPPLY-SIDE ASSESSMENT ADEQUATE?

A. No, the supply-side assessment provides very little information on ENGI's plans to meet forecast requirements over the planning period. For example, while the Company identifies both its gas commodity and pipeline capacity contracts that are scheduled to expire during the planning period, there is no discussion of the cost effectiveness of renewing those contracts at existing or alternate levels or replacing them with new contracts. In addition, there is virtually no discussion of available options (such as proposed new pipeline projects, proposed new storage projects, or expansion of existing LNG /LP-Air capacity) to supply the balance between existing resources (including or excluding expiring contracts) and forecast demand, let alone an analysis of the costs of these options relative to each other. Instead, ENGI appears content to: (i) summarize its existing capacity and supply contracts; (ii) describe the planning process used to identify realistic resource options; and (iii) describe the capabilities of the model used to determine the optimal portfolio to meet a given demand.

Q. YOU SAID THAT THE IRP DOES NOT ADDRESS WHETHER EXISTING CONTRACTS WILL BE RENEWED OR REPLACED. WAS THIS OMISSION RAISED WITH THE COMPANY?

A. Yes. While the Company assumed for the purpose of calculating the resource balance that almost all of its expiring contracts would be renewed at existing levels, it stated that it expects to obtain the necessary information to make final decisions on renewal/replacement by issuing RFPs close to the time the contracts are scheduled to expire.

Q. IS THIS AN EFFICIENT PROCESS?

A. No. The identification and evaluation of all reasonably available alternatives to renewing existing contracts will provide the Company with the necessary information to prepare an RFP that targets resources that are most likely to supply the resource balance at least cost. Absent such an evaluation, the Company runs the risk of soliciting sub-optimal supply resources that unnecessarily increase costs to customers. In addition, since the need for new resources is dependent in part on whether existing contracts will be renewed and, if so, at what level, the

Company must first decide what it intends to do with expiring contracts before it can develop a plan to acquire new resources. Thus, absent evaluation, the RFP is unlikely to target the optimal type and quantity of resources.

Q. THE ASSESSMENT OF SUPPLY AND DEMAND INDICATES A NEED FOR INCREMENTAL CAPACITY IN 2009/10 UNDER THE BASE CASE DESIGN DAY FORECAST AND INCREMENTAL SUPPLIES IN 2008/09 UNDER THE BASE CASE DESIGN YEAR FORECAST.[12] HOW DOES THE COMPANY PLAN TO MEET THESE NEEDS?

A. The IRP does not state how these needs will be met. It does state, however, that the Company has initiated discussions with Tennessee Gas Pipeline ("Tennessee") regarding incremental capacity additions.[13] Also, in response to discovery, the Company stated that an expansion of Tennessee's Concord Lateral, which is currently at capacity, "will be required in order to serve the incremental requirements of EnergyNorth Customers."[14]

Q. WHAT IS THE CONCORD LATERAL?

A. The Concord Lateral is the northernmost branch of Tennessee's main line originating in Dracut, Massachusetts and terminating in Concord, New

[12] IRP, Charts IV-D-3 and IV-D-1 respectively.
[13] IRP, page IV-20.
[14] ENGI Response to Staff 1-27.

Hampshire. The lateral is located in Tennessee's Zone 6. Because all of the Company's pipeline supplies must pass through this corridor to reach ENGI's city gates, any capacity constraint on this line must be removed in order to access new pipeline supplies. An expansion of the Concord Lateral would provide access to additional pipeline supplies at Dracut, where Tennessee interconnects with both Maritimes & Northeast Pipeline ("Maritimes") and Portland Natural Gas Transmission System ("PNGTS"). The Company believes that it could obtain existing firm capacity on either of these pipelines and thus avoid the costs of an expansion project on these or other pipelines.

Q. DID THE COMPANY DEMONSTRATE IN THE IRP OR OTHERWISE THAT EXPANDING THE CONCORD LATERAL AND PURCHASING FIRM SUPPLIES ON EITHER MARITIMES OR PNGTS IS THE LEAST COST OPTION TO SUPPLY THE INCREMENTAL VOLUMES?

A. No, it did not.

Q. IS IT LIKELY, IN STAFF'S OPINION, THAT EXPANSION OF THE CONCORD LATERAL WOULD BE LEAST COST?

A. No. Because new pipeline projects are often associated with high fixed capacity costs and low variable commodity costs, they tend to be best suited to meeting high load factor (i.e., baseload) demand increments. This is not the situation described in the IRP. The Company's assessment of supply and demand under the design year forecast indicates that gas supplies will be short in the last three years of the five year planning period, but only in the peak winter months. More importantly, the number of days in each month that gas supplies are projected to fall short of requirements is never more than ten. See Table 1 below. This information points to a low load factor (i.e., peaking) demand increment and, hence, the need for peaking capacity and associated supplies to fill the shortfall at least cost.[15] Peaking capacity options include expanding the capacity of the Company's existing vaporized propane-air ("LP-Air") and liquefied natural gas ("LNG") facilities or adding new capacity at different locations.

Table 1

Design Year Shortfall Analysis

Year	Date	Resource Shortfall (MMBtu)
2008/09	19-Nov	2,987
	20-Nov	4,578
	26-Dec	27,225
	27-Dec	14,993
	28-Dec	3,476
	Annual	53,259
2009/10	26-Dec	14,631
	27-Dec	11,260
	28-Dec	6,189
	3-Jan	1,440
	4-Jan	9,109
	5-Jan	5,309
	Annual	47,938
2010/11	23-Dec	6,044
	26-Dec	34,265
	27-Dec	19,277
	28-Dec	11,934
	29-Dec	793
	30-Dec	4,676
	3-Jan	5,176
	4-Jan	19,837
	5-Jan	19,664
	31-Jan	6,336
	Annual	128,002

[15] It should be noted that the Company recognizes that the "shape" of the demand increment is a critical factor in identifying the type of resource needed to meet demand at least cost. IRP, pages IV-15 and 16.

Q. WHAT IS THE TOTAL CAPABILITY OF ENGI'S EXISTING LP-AIR FACILITIES?

A. ENGI maintains four LP-Air facilities with a combined storage capacity of 115,000 Dth, and has the ability to vaporize approximately 50,000 Dth per day. At the maximum vaporization capacity, this provides a little over two days of supply.

Q. WHAT IS THE TOTAL CAPABILITY OF ENGI'S EXISTING LNG FACILITIES?

A. ENGI maintains three small LNG facilities with a combined storage capacity of 13,500 Dth, and has the ability to vaporize approximately 24,000 Dth per day. At the maximum vaporization capacity, this provides a little over half a day of supply.

Q. DID THE COMPANY COMPARE THE COSTS OF PEAKING CAPACITY AND PIPELINE CAPACITY OPTIONS BEFORE INITIATING DISCUSSIONS WITH TENNESSEE REGARDING THE CONCORD LATERAL?

A. No comparative analysis of baseload and peaking resources was included in the IRP. The Company did, however, provide Staff with Tennessee's proposed transportation rate for a [redacted] Dth expansion of the lateral: namely, [redacted] per Dth-month.[16] Despite the fact that the lateral is located entirely within Zone 6, the

[16] Confidential ENGI response to Staff 1-37. The Dth expansion is consistent with 19,660 Dth design day shortfall projected for 2010-11 in Chart IV-D-3 of the IRP. Also, a Dth capacity expansion of LP-Air or LNG facilities does not seem unrealistic given the existing capacity of ENGI's supplemental facilities.

proposed rate is more than times the existing short-haul (Zone 6 to Zone 6) firm transportation rate of $3.16 per Dth-month.[17] Based on this rate, we estimate that expansion of the lateral alone would cost ENGI approximately [redacted] million annually.[18] This compares with only $1.1 million annually for a Dth expansion of the Company's LP-air or LNG vaporization capacity.[19] When the cost of capacity on Maritimes or PNGTS is taken into account, the higher capacity costs of additional pipeline supplies seem too great to be offset by lower commodity costs relative to propane or LNG.

Q. WHAT ARE STAFF'S CONCLUSIONS REGARDING ENGI'S SUPPLY-SIDE ASSESSMENT?

A. Integrated resource planning involves, among other things, the systematic assessment of reasonably available supply-side resource options to satisfy customer requirements at the lowest cost consistent with maintaining supply reliability. ENGI's IRP includes virtually no discussion, much less evaluation, of the available supply-side resource options to meet the projected incremental increase in customer demand over the planning period. In particular, Staff finds that ENGI's proposal to expand the Concord Lateral and purchase firm capacity on Maritimes or PNGTS is lacking in analytical support and unlikely to be cost-effective given what is known about the shape of demand increment and the costs

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[17] While new pipeline capacity is known to be more expensive than existing capacity, this differential seems too great to be justified on cost grounds alone.
[18] This estimate is based on Staff's understanding of the offer proposed Tennessee. Staff attempted to obtain the Company's interpretation of the offer but did not receive a response prior to filing this testimony.
[19] ENGI response to Staff 1-58.

of competing supply resources. For this reason, Staff recommends that the supply-side assessment be found not adequate.

Q. HOW SHOULD THE SUPPLY-SIDE ASSESSMENT BE REVISED IN FUTURE IRP FILINGS?

A. The Company should include in its next IRP a complete description of the analytical process used to evaluate available supply-side resources. That process should include the following phases: (a) identification of all available and potentially available capacity resources capable of meeting the demand increment over the planning period, along with their respective costs; (b) identification of each existing resource that can be varied during the planning period, along with the change in capacity; (c) presentation of the results of planning model runs to evaluate various resource configurations under different gas demand and gas price scenarios including the ranking of resource configurations.

The decision whether to meet the demand increment with new pipeline capacity, new storage capacity, supplemental LNG /LP-Air capacity, or a combination of all three is complex and will require the use of a long-term planning model that calculates the net present value of the resource configurations selected to meet the demand increment. From this analysis, the Company should be able to identify the mix and timing of resource additions that minimize the total costs of the portfolio under a set of price and demand forecast assumptions. These resource additions should be presented in both tabular and graphical form in the next IRP.

Q. THE COMPANY NOTES THAT IT WAS MADE A PARTY TO DOCKET DG 06-033, THE NORTHERN UTILITIES PROCEEDING TO ESTABLISH A CHARGE TO RECOVER THE COSTS OF THE PROPOSED 30% CAPACITY RESERVE. IN THAT PROCEEDING, THE COMPANY AGREED TO ADDRESS IN THIS IRP THE APPROPRIATENESS OF ESTABLISHING A CAPACITY RESERVE TO PROTECT AGAINST THE RISK THAT GRANDFATHERED TRANSPORTATION CUSTOMERS RETURN UNEXPECTIDLY TO SALES SERVICE. DID THE COMPANY ADDRESS THAT ISSUE IN ITS IRP?

A. Yes, it did. According to the Company, the data on the historical performance of marketers supplying the loads of transportation customers indicate that: (i) there have been minimal delivery failures attributable to under deliveries by suppliers on behalf of transportation customers; and (ii) it is impossible to separate the under deliveries for grandfathered customers from under deliveries for non-grandfathered customers. Based on these conclusions, the Company took the position that the establishment of a capacity reserve is not currently warranted.

Q. DOES STAFF SUPPORT ENGI'S POSITION?

A. Yes. The Company's argument, in effect, is that there is no evidence to support the proposition that customers would benefit from such a reserve. Accordingly, since the costs of establishing the reserve are certainly greater than zero, the net benefit to customers of holding a reserve is likely to negative, not positive.

Q. IN THE EVENT THE COMMISSION DETERMINES THAT IT IS APPROPRIATE TO PLAN FOR THE GAS SUPPLY NEEDS OF GRANDFATHERED CUSTOMERS, THE COMPANY HAS TAKEN THE POSITION THAT: (I) ENGI SHOULD PLAN FOR 100% OF THOSE NEEDS; AND (II) ALL CUSTOMERS SHOULD PAY FOR THE COST OF ACQUIRING THE NECESSARY INCREMENTAL RESOURCES. DOES STAFF AGREE WITH THESE POSITIONS?

A. No. Regarding the first issue, if the Company believes there is no evidence to support a 30% reserve, it is difficult to understand how a 100% reserve could reasonably be supported.[20] Regarding the second issue, Staff believes that the costs of holding any reserve should be recovered from grandfathered transportation customers only. This is because the reserve's function is to maintain supply reliability to firm sales and firm non-grandfathered transportation customers in the event one or more suppliers to grandfathered customers fail to deliver.

[20] The Commission should also include in its analysis the fact that the costs of holding a 100% reserve are substantially higher than the costs of a 30% reserve.

When considering the first issue, the Commission should keep in mind that the Company has proposed elsewhere in this IRP to substantially increase its design day and design year planning standards from their current level of 1 in 30 years to one in 43 years and one in 47 years respectively. Given the high cost of increasing reliability, it would seem reasonable and sensible for the Commission to condition its approval of an additional reserve on an explicit showing that the associated costs would be fully offset by measurable improvements in reliability. The Company's filing contains no such facts or figures.

Finally on this fist issue, Staff contends that ENGI has no need to plan to serve all grandfathered customers at the same time. The reason is that the assumption that all suppliers would not only fail to perform at the same time but would do so on the peak day is simply not plausible. While supplier failure may not qualify as a random event, the statistical probability of all suppliers failing to perform on the peak day must be extremely small. If that probability could be estimated, ENGI would need only to plan to serve the product of that probability and the peak day coincident demand of all grandfathered customers.

VI. INTEGRATION OF DEMAND-SIDE AND SUPPLY-SIDE RESOURCE OPTIONS

Q. INTEGRATED RESOURCE PLANNING FILINGS MUST, BY DEFINITION, ADDRESS HOW TO IDENTIFY THE OPTIMAL MIX OF DEMAND-SIDE AND SUPPLY-SIDE RESOURCES THAT MEETS FORECASTED

DEMANDS AT LEAST COST. DOES THE COMPANY'S IRP SATISFY THAT REQUIREMENT?

A. No. The IRP neither discusses the process for integrating cost effective demand-side and supply-side resources nor identifies the preferred portfolio of existing and new resources that satisfies forecasted loads at least cost over the planning period.

Q. THE COMPANY STATES IN THE EXECUTIVE SUMMARY TO ITS IRP THAT THE FILING DEMONSTRATES THAT ITS PLANNING PROCESS ENSURES THAT IT MAINTAINS A RELIABLE RESOURCE PORTFOLIO AND ENERGY SUPPLY TO MEET THE FORECASTED NEEDS OF ITS CUSTOMERS AT THE LOWEST POSSIBLE COST. WHY DOES STAFF DISAGREE WITH THIS STATEMENT?

A. I disagree because the IRP does not even identify the new resources (supply- or demand-side) that are needed to meet the resource balance, never mind demonstrate that they are least cost.

Q. WHAT IS THE RESOURCE BALANCE?

A. The Company's attachments show that the peak demand gap is expected to increase from 0 MMBtu in 2006/07 to 19,660 MMBtu in 2010/11 under design day conditions.

Q. WHAT DOES STAFF RECOMMEND REGARDING THE INTEGRATION OF SUPPLY-SIDE AND DEMAND-SIDE RESOURCES?

A. Standard integrated resource planning practice requires each utility to include in its IRP a description of the process it uses to determine the optimal mix of demand-side and supply-side resources. I urge the Commission to require ENGI to comply with this standard practice in its next IRP filing.

Q. WHEN SHOULD THAT FILING BE MADE?

A. Staff recommends that the next IRP be filed no later than two years after the 2006 IRP was filed.

Q. IN SUMMARY, WHAT IS STAFF'S OVERALL RECOMMENDATION REGARDING THE COMPANY'S 2006 IRP?

A. Staff recommends that the IRP be found not adequate in the instances set forth herein.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

EXHIBIT GRM-1

GEORGE R. McCLUSKEY

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Analyst

George McCluskey is a ratemaking specialist with over 20 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, Lease 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