STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

DG 10-017

In the Matter of:
EnergyNorth Natural Gas, Inc. d/b/a National Grid NH
Petition for Permanent Increase in Delivery Rates

Direct Testimony

of

Robert J. Wyatt
Utility Analyst IV

October 22, 2010

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**LIST OF ATTACHMENTS**

**INTRODUCTION**

**Q. Please state your name, occupation and business address.**

A. My name is Robert J. Wyatt. I am employed by the New Hampshire Public Utilities Commission (Commission) as a utility analyst in the Gas & Water Division. My business address is 21 South Fruit Street, Suite 10, Concord, New Hampshire 03301.

**Q. Please describe your background and professional experience.**

A. I am an analyst with over 25 years experience in the natural gas business with a focus on gas supply operations, and the analysis of costs and revenues. I joined the Commission in March 2002 as a utility analyst in the Gas & Water Division specializing in the operation of gas and steam utility systems. Prior to coming to the NH PUC, from August 2000 to March 2002 I worked as an energy and raw materials analyst for Hitchiner Manufacturing Co., an investment casting foundry in southern NH. I was responsible for natural gas and propane contracting for the company's New Hampshire operations, which at the time was one of the largest end-use consumers of natural gas and electricity in the state. At Hitchiner I was a member of the company's energy conservation committee and also responsible for energy use tracking, cost analysis, invoice reconciliation, forecasting, budgeting and reporting to senior management. From 1985 through 2000 I worked for EnergyNorth, Inc., the NH based parent company of EnergyNorth Natural Gas, Inc. where I began my professional career as a supervisor in the meter reading and customer accounting department. In 1987 I accepted a position as gas dispatch supervisor, and then in 1988 I was promoted to gas supply analyst, both of which were in the gas supply department of EnergyNorth. As gas dispatch supervisor I was responsible pipeline balancing, the peakshaving plant supply resource function, gas supply inventory management and supply invoice reconciliations. In the gas supply analyst position I was responsible for the development of gas supply forecast models, interruptible customer pricing and sales, supply contract administration, short term spot gas purchasing, seven day storage requirement calculations and "grandfathered" transportation customer supply/demand balancing, billing, supplier monitoring and administration. I have a Bachelor of Science degree with a major in Technical Management and an Associate in Engineering degree with a major in Electronic Engineering Technology. I have completed several professional development workshops over the years including cost of service, cost allocation and rate design. A copy of my resume is included as Attachment RJW-1.

**Q. Have you testified as a Staff witness before this Commission in previous dockets?**

**A.** Yes I have, in cost of gas, cost of (steam) energy and other gas and steam related proceedings.

**Q. What is the purpose of your testimony in this proceeding?**

**A.** My testimony will address a number of issues raised in the rate design testimony and supporting attachments filed on behalf of EnergyNorth Natural Gas, Inc. d/b/a National Grid NH ("National Grid NH " or "Company") by Paul M. Normand, of Management Applications Consulting. Mr. Normand's primary responsibilities in this proceeding are to: (i) develop appropriate methods for allocating to customer classes the distribution cost of service (i.e., revenue requirements) requested by the Company; and (ii) design reasonable rates that collect those class revenue requirements. In addition, Mr. Normand performed lead-lag studies to support the proposed cash working capital allowances for delivery-related and supply-related services.

The focus of my testimony is to determine whether the methods that underlie his analyses are consistent with those approved by the Commission in prior rate filings, that the assumptions are reasonable, that the data are accurate, and most importantly, that the results are just and reasonable.

In Section II, I comment on the lead-lag studies filed April 23, 2010, which support the cash working capital allowances proposed for delivery-related and supply-related services. In Section III, I comment on the accounting cost of service study filed February 26, 2010. In Section IV, I present the results of my review of the marginal cost of service study filed February 26, 2010. In Section V, I comment on the rate design proposals, which are based on the results of the marginal cost study. I also note that Attachment RJW-5 provides each data response identified in the testimony, organized by the order in which they are referenced.

**Q. Before you begin your assessment of Mr. Normand's testimony, please summarize your conclusions and recommendations.**

**A.** My conclusions and recommendations are summarized as follows:

1) Mr. Normand's computation of National Grid NH's cash working capital requirements for delivery related service is consistent with the methodology recommended by Staff witness McCluskey in Docket No. DG 08-009. The results of Mr. Normand's delivery-related cash working capital calculation are consistent with a separate calculation completed by Staff.

2) My testimony shows that Mr. Normand's delivery-related lead-lag study is consistent with the methodology recommended by Mr. McCluskey in his testimony in Docket No. 08-009. Specifically, the items that Mr. Normand describes as non-cash related are excluded in the study.

3) The results of Mr. Normand's computation of National Grid NH's cash working capital requirement for supply-related service are consistent with Staff's separate

computation. As regards supply-related service, I recommend that the Company continue to perform a lead-lag study on purchased gas costs every three years for the purpose of adjusting the cash working capital allowance included in the cost of gas rate, consistent with the partial settlement agreement in Docket No. DG 08-009.

4) Mr. Normand's accounting cost of service study is used to allocate the test year revenue requirement to the delivery function, the production function, the direct gas cost function and the indirect gas cost function. This study is consistent with the studies utilized in several prior rates-related cases before the Commission.

5) Mr. Normand's marginal cost study overstates the marginal cost of production capacity. I contend that his computations used two incorrect or unsupported assumptions that, in combination, resulted in the overstatement of the marginal cost of production capacity. After making my adjustments to correct Mr. Normand's analysis, the calculations show the present value unit cost of adding production capacity is $548.54, which is approximately a 64 percent reduction from Mr. Normand's result.

6) Correcting for these errors and flawed assumptions and incorporating the other corrections identified through the normal review and during the discovery process, I conclude that Mr. Normand's marginal cost study provides sufficient support for the proposed new class revenue requirements and the re-designed rates. Based on my adjustments and corrections, the new total marginal annual revenue requirements for delivery service are $65,376,241. This will require an adjustment to total marginal revenue requirements of -$9,764,820, which will require a 15% reduction, to match the estimated delivery revenue requirements of $55,611,421.

7) Mr. Normand's proposal to limit the maximum rate increase for any rate class, excluding the residential non-heating rate class, to 125 percent of the average overall

delivery rate increase is reasonable given the need for rate stability. Although the proposed higher cap of 150 percent for the residential non-heating R-1 rate class is supported by the results of the marginal cost study, I believe it is inequitable to single out this class of customers for a higher cap on the delivery rate increase. Specifically, in Attachment PMN-RD-4-2, page 1, the R-1 cap of 150 percent results in a revenue target that is 63 percent of the marginal cost to serve. By instead using the 125 percent cap for R-1, the revenue target is 60 percent of the marginal cost to serve. Using this same 125 percent cap for the commercial and industrial high load factor G-54 and G-63 rate classes, the revenue targets are 48 percent and 72 percent, respectively, of the marginal costs to serve. Therefore, based on the assumption that the Company's overall rate increase request is determined to be reasonable, I recommend that a 125 percent revenue cap be adopted for all rate classes.

8.) Mr. Normand's proposed rate redesign in this filing results in a greater apportionment of the R-3, R-4 and G-41classes' target revenue requirements to customer charges. To reduce the bill impacts on small use customers in these classes, I recommend that customer charges be slightly lower than proposed and declining block rate structures be replaced with flat rates.

## II. CASH WORKING CAPITAL

**Q. What is cash working capital**?

**A.** Cash working capital is the amount of investor supplied capital needed to fund the timing difference between a utility's payment of supply-related or delivery-related expenses and the receipt of the corresponding revenues from customers. If payment of expenses occurs before the receipt of revenues, there is a positive cash working capital need. Likewise, if payment of expenses occurs after revenues are received, there is a negative cash working capital need. The allowances for supply-related and delivery-related cash working capital in rates are intended to compensate the utility for the cost to finance investor supplied working capital.

**Q. Are the allowances for supply-related and delivery-related cash working capital collected through delivery rates or the cost of gas rates?**

**A.** Delivery-related cash working capital is typically an addition to distribution rate base and, therefore, the associated financing cost or return on capital is collected through delivery rates. Supply-related cash working capital is collected as an indirect gas cost allowance in the cost of gas.

**Q. What determines the amount of supply-related and delivery-related cash working capital to be included in rate base?**

**A.** Because cash working capital is not recorded in a utility's books, the amounts included in the cost of gas and rate base must be quantified using a detailed lead-lag study.[1] A lead-lag study is a methodical analysis of a utility's cash flows for the purpose of determining the average net time, lag or lead, expressed in days, for a particular service. Such studies are comprised of two major components: the calculation of a revenue lag, which is defined as the average number of days between the provision of service to customers and the collection of the related revenues; and the calculation of an expense lead, which is defined as the average number of days between the receipt of goods or services supplied by vendors/contractors and the payment for such goods and services. The net of these two quantities is divided by the number of days in the year to produce a ratio that is then

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1 The amount to be included in rate base can also be determined using a formula method. The most common method is referred to as the 45-day formula.

multiplied by the corresponding annual expense[2] to produce the utility's cash working capital requirement.

**Q. You defined a lead-lag study as a methodical analysis of a utility's cash flows. Does this analysis cover all supply-related and delivery-related cost of service items?**

**A.** No. As noted above, cash working capital is defined as the amount of investor supplied capital needed to fund the delay between the payment of expenses and the receipt of associated revenues. It follows, therefore, that if a supply or delivery related cost of service item does not involve current cash expenditures, for example, depreciation and uncollectible accounts, it cannot contribute to the need for cash working capital. Accordingly, lead-lag studies should exclude such non-cash expense items.

**Q. Did Mr. Normand use a lead-lag study to calculate the cash working capital used in rate base?**

**A.** Mr. Normand conducted a lead-lag study to calculate the net lag for the test year total revenue requirement which included both supply-related and delivery-related revenue requirements. Then he did a separate calculation of the net lag for the test year supply-related revenue requirement only. Based on the calculations from his study, Mr. Normand derived a delivery-related cash working capital requirement of $1,507,192.[3]

**Q. Did Mr. Normand's lead-lag study exclude all non-cash items as recommended by Staff witness McCluskey in docket No. DG 08-009?**

**A.** Yes. The results of Mr. Normand's calculations, as shown in Attachment PMN-LL-2, page 1 of 3, exclude non-cash items from his final calculations. His delivery-related

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2 That is, the supply-related expense if the net lag corresponds to commodity service or the non-supply related costs and expenses if the net lag corresponds to delivery service.

3 See Attachment PMN-LL-2, page 1, line 44, column 5.

lead-lag study correctly removes the non-cash items Uncollectible Accounts Expense, Depreciation & Amortization Expense, Deferred Income Taxes and Income on Return.[4]

**Q. Was Staff able to determine the non-cash items were effectively removed from the lead-lag study?**

**A.** Staff removed the non-cash expense amounts for these items and to be consistent with Mr. Normand's calculation, also removed the interest amount on customer deposits[5] from its separate calculation of delivery-related expenses and came to a delivery-related revenue requirement of $39,083,543 and a weighted average expense lag of 39.09 days. This resulted in a corresponding net lag of 14.08 days and a cash working capital requirement of $1,507,549. Staff's delivery-related net lag and cash working capital results of the calculation, except for slight rounding differences, compare favorably to Mr. Normand's results[6].

**Q. Do you agree with Mr. Normand's proposed supply-related cash working capital requirement of $4,385,813[7]?**

**A.** Yes. Using the supply-related test year purchased gas cost amount of $112,156,611, and the net lag of 14.27 days, Staff's calculation resulted in a supply-related cash working capital requirement of $4,384,863. Again, except for slight rounding differences, Staff's computation compared favorably to Mr. Normand's result.

**Q. Is there a need to revise the delivery-related cash working capital requirement?**

**A.** Yes. The cash working capital calculations are based on *pro forma* costs, which use the test year return and a calculation of income taxes based on that level of return. Assuming

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4 Although Income on Return is not strictly a non-cash item, it should be excluded from lead-lag studies for the reasons set forth in Mr. McCluskey's testimony in Docket DG 08-009.

5 See attachment PMN-LL-2, Page 3 of 3, Note 1.

6 See attachment PMN-LL-2, Page 1 of 3, line 44, column 5 and line 45, column 3.

7 See attachment PMN-LL-2, Page 1, line 38, column 5.

the allowed return in this case is different, the level of delivery-related cash working capital will need to be recalculated using the allowed return level. This change in the return level will change the computed level of income taxes.

## III. ACCOUNTING COST OF SERVICE STUDY

**Q. Please provide a brief overview of Mr. Normand's Accounting Cost of Service Study.**

**A.** The Company uses the accounting cost of service study (COSS) in this case to allocate test year revenue requirements to the following functions: delivery related revenue requirements, production-related revenue requirements, direct gas costs, and indirect gas costs. The methodology underlying the COSS is consistent with what was filed in several earlier cases before the Commission including the Company's previous delivery rate filing in docket DG 08-009. This methodology was also used by National Grid NH to update indirect gas costs in Docket DG 06-121, and in the revenue neutral rate redesign filing in docket DG 00-063.

**Q. What does the COSS accomplish?**

**A.** Basically, the COSS unbundles the costs to provide delivery service from gas supply and gas production costs. The production function is further unbundled into direct gas costs and indirect gas costs. Delivery costs, along with a small portion of revenue requirements associated with the Company's production facilities are recovered through base delivery rates. This treatment is in recognition of the fact that certain production facilities provide both gas supply service during the peak period and distribution system pressure support. The remaining revenue requirements associated with the production facilities are allocated to the indirect gas cost function and recovered along with direct gas costs through the Company's regular cost of gas filings.

**Q. Are there other components to the indirect gas cost rate?**

**A.** Yes. Along with supply-related revenue requirements for the LNG and propane air production facilities, other items include Miscellaneous Production Costs, Bad Debt and Working Capital.

**Q. How often are the indirect gas cost components updated?**

**A.** Once the indirect gas costs are approved in a delivery service rate case, they typically do not change until a future rate case, unless the Commission establishes a timetable for periodic updates.

**Q. Is there an approved schedule for the update of indirect gas costs?**

**A.** Not completely. The settlement approved in DG 08-009 by Order No. 24,972 requires the Company to perform a lead-lag study on purchased gas costs every three years, for the purpose of updating the Company's supply-related cash working capital allowance.

**Q. Do you the believe the Company's functionalization of revenue requirements is reasonable?**

**A.** Yes. As I stated earlier, the methodology underlying the COSS is consistent with what has been filed in several earlier cases before the Commission including the Company's previous delivery rate filing in docket DG 08-009.

## IV. MARGINAL COST OF SERVICE STUDY

**Q. Please provide a brief overview of Mr. Normand's marginal cost study.**

**A.** Instead of assigning the Company's proposed delivery-related revenue requirement to customer classes based on the accounting cost of service study, Mr. Normand uses a marginal cost study for that purpose. A marginal cost study seeks to estimate the costs of providing one more or one less unit of service, which, in the case of delivery service, are comprised of capacity-related and customer-related costs.  Once estimated, these unit costs are multiplied by the corresponding billing determinants for each customer class to arrive at the marginal cost-based class revenue requirements. To the extent the sum of these marginal cost-based class revenue requirements differs from the total delivery-related revenue requirement, the marginal cost-based class revenue requirements are adjusted to provide the utility an opportunity to recover its total revenue requirement. Mr. Normand's marginal cost study provides marginal capacity cost estimates for each component of the Company’s distribution system including the marginal cost of operations and maintenance. He also provides an estimate of the marginal cost of adding to the system a single customer in each customer class.  Based on these cost estimates and the corresponding class billing determinants, Mr. Normand estimates that marginal-cost based charges would produce 21.35% more revenue than the Company's total delivery-related revenue requirement.[8]  In order to limit revenue recovery to the Company's revenue requirement, Mr. Normand decreased the marginal class revenues uniformly by 21.35%, subject to the constraint that no rate class, with exception of the residential non-heat rate class, would receive a rate increase greater than 125% of the average requested increase. The 125% factor acts as a revenue cap for each rate class except the residential non-heat rate class, which is capped at 150%.

**Q.** **What does the marginal cost study show?**

**A.** The principal conclusion of Mr. Normand's marginal cost study is that the commercial and industrial rate classes with load factors greater than 90% and all residential rate

8 See attachment PMN-3, Page 37, line 4, column 12.

classes are paying substantially less than marginal cost. In contrast, most other rate classes are paying more than marginal cost.

**Q. Do you have any concerns with the assumptions or computations used in the study?**

A. Yes. I will recommend two adjustments related to incorrect or unsupported assumptions in Mr. Normand's calculation of the marginal cost of production capacity. First, in Attachment PNM-3, page 1, line 12, Mr. Normand uses an assumption that there will be a need for production plant investment to meet a capacity shortfall anticipated in the year following the test year, which translates into the winter period 2009/10. The assumption of a capacity shortfall in 2009/10 is clearly invalid based on data filed by the Company in its 2010 Integrated Resource Plan (2010 IRP) proceeding, docket no. DG 10-041. In that proceeding, Staff contends that the data show that the Company reverted from a capacity shortfall to a capacity excess when it added 30,000 Dth per day of new Tennessee Gas Pipeline capacity on November 1, 2009. This project, commonly referred to as the Concord Lateral Expansion project, was approved by the Commission in Docket DG 07-101. In Chart 1 below,

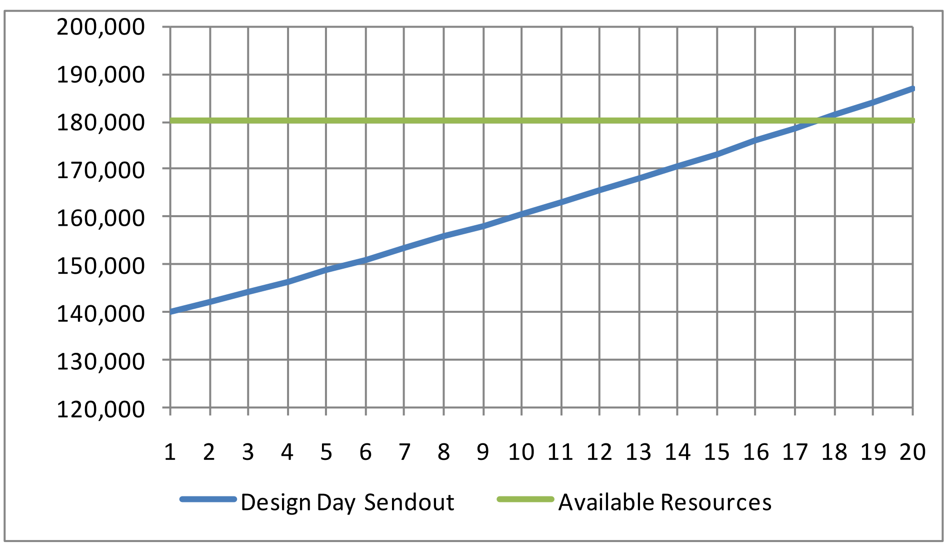


**Chart 1 (Design Day Demand vs. Available Resource Volumes in Dth Units)**

using the Company's design day demand forecast data for the years 2010/11 through 2015/16[9] (i.e., years 1 through 5 in Chart 1) and assuming peak demand continues to grow thereafter at the average rate for those 5 years, I show that the excess capacity may continue into the future until sometime in the years 2027 or 2028 (i.e., years 17 or 18 in Chart 1).[10] Obviously, much can happen between now and then related to the Company's balance between design day demand requirements and available supply resources. However, it is Staff's contention, based on current information, that it is unlikely that the Company will have a need to add new production supply capacity any time soon. This means that the present value cost of installing a production facility in 2027 (i.e., the marginal cost of production capacity) will in all likelihood be less than what Mr. Normand is projecting in his marginal cost calculation. My first adjustment to Mr. Normand's marginal cost study model changes the first year of capacity shortfall from his assumption of 2009 to my assumption of 2027 (i.e., 17 years out from the 2010/11 design day estimate from the 2010 IRP). Keeping in mind this exercise is a theoretical construct, this adjustment changes the estimated need for the production capacity from year 1 to year 19. It is based on what I consider a conservative estimate, using the Company's design day demand figures that do not include any DSM measures. Assuming DSM measures will continue to be included in the Company's resource plans, the adjusted estimate for new production capacity requirements is a conservative one. This adjustment to Mr. Normand's production capacity cost calculation in Table 1 of his study results in a present value of production capacity, as shown in Attachment RJW-3, page 1, line 20, column 2, of $548.54, which is a 64 percent reduction in comparison to

9 See DG 10-041, 2010 IRP, Appendix D, pages 4-8, Firm Sendout.
10 Note that the excess capacity period could be even longer because the design day demands reflected in the Chart do not take into account the impact of future demand side management (DSM) programs.

Mr. Normand's outcome. Staff also performed a separate present value calculation, as shown in the Attachment RJW-4, page 1, line 58, column K, in which the result is a production capacity unit cost of $594.62/Dth. Staff performed separate marginal cost calculations using each present value cost of production capacity and as expected, the difference on marginal costs was small. In the interest of consistency Staff will focus on the present value result using Mr. Normand's model, which then divides the full present value production cost between supply-related and pressure support-related costs.

Second, Mr. Normand's analysis (*see* Att. PMN-3, page 3, line 16) overstates the existing design day pressure support requirement in Tilton by multiplying the Company's Stoner model design hour results by 24 hours instead of the engineer's more commonly accepted 20 hour assumption for a conservative estimate of design day demand. The 20 hour assumption is used by Mr. Normand in his development of the marginal cost of distribution-related capacity reinforcement investment (Att. PMN-3, page 6, lines 2-8) and again in response to Staff 1-169 e), dated June 1, 2010, where he further explains the design day peak volumes are derived from the Stoner model design hour Dth for any given year times 20 hours. These results run somewhat more conservative (i.e., higher) than the design Day calculations used in the 2010 IRP, but are used by engineers for distribution system design purposes, not for supply planning purposes. I recommend that the calculation to convert the design hour pressure support requirement to a design day pressure support requirement be computed by multiplying the Stoner model design hour requirement times 20 hours. This correction reduces the Company's pressure support requirement from 11.9 percent to 9.9 percent. Making these to corrections result in a pressure support related unit cost of production capacity investment of $54.39, which is a 70 percent reduction to Mr. Normand's result.

**Q. Are there any other concerns with Mr. Normand's assumptions used to determine the marginal cost of production capacity?**

**A.** Yes. I have two concerns with Mr. Normand's choice for a production plant investment. First, the project capacity of 25,200 Dth per day is much too high, given the current demand requirements in Tilton, or any other location on the National Grid NH system.[11] Second, the propane alternative is called into question, for both operational and economic reasons. Using this propane alternative seems out of step with two of the Company's primary responsibilities as a natural gas distribution company, i.e., to provide safe, reliable service and to provide gas commodity alternatives that are favorably priced in the market.

**Q. Why do you call into question the design capacity of the propane production facility Mr. Normand used to compute the marginal cost of production capacity?**

**A.** In Mr. Normand's own words, the use of the peaker methodology to determine the marginal cost of production capacity should be based on reasonable economic and operational assumptions[12]. The propane air plant alternative used in his marginal cost study is neither operationally or economically reasonable because it would effectively convert the Tilton distribution system into a propane air system, with a substantial excess in plant capacity. Even in year 10, based on growth projections provided by Mr. Normand[13], the total Tilton design day requirements are projected to be 12,060 Dth. With currently existing pipeline and production capacity available in Tilton, it would take several decades of higher than average demand growth to be able to utilize the additional 25,200 Dth/day capacity of this propane plant alternative. Second, National Grid NH is a

11 See attachment PMN-3, line 22, column 2, which indicates the proposed propane air peakshaving plant alternative had a design capacity of 25,200 Dth per day.

12 Response to data request Staff 1-183, dated June 2, 2010

13 Response to data response to Staff DR 1-185.

natural gas utility and there can be service quality issues in trying to economically integrate and operate a propane peaking plant of this size anywhere in National Grid NH's distribution system.

**Q. Why do you call into question the economic and operational efficiencies of the propane production facility Mr. Normand used to compute the marginal cost of production capacity?**

**A.** First, propane commodity costs are typically priced at a premium over other fuels. One needs to look no further than in the cost of gas reconciliations from recent winter periods.[14] Additionally, the oversized propane plant alternative used in Mr. Normand's calculations comes with a higher cost and higher associated Company adders and overheads. Operationally, special mixing requirements that are necessary to reduce propane's specific gravity to levels compatible with natural gas appliances and equipment[15] make this a less desirable choice. With Staff follow up set two and set three data requests that were specific to Mr. Normand's alternative for production capacity, the Company first submitted a supplemental response to Staff 1-183 stating the propane peaker plant incorrectly identified Tilton as the production capacity shortfall location, and instead should have referred to plants located in Nashua and Concord. This also did not make sense because the one propane plant used in Mr. Normand's calculations would not be able to serve both divisions and, similar to the operational problems that would be encountered by it in the Tilton division, this alternative would also be too large for the Concord division. Finally, in response to Staff data request 3-37, the Company indicated there were no pressure problems in Nashua or Concord and that the pressure support

14 Source, DG 10-230, prior peak period reconciliation, Confidential Schedule 8, Line 33, not attached

15 Propane has a specific gravity of about 1.5, which means it is heavier than normal atmosphere. Natural gas, however, has a specific gravity of approximately 0.58, meaning it is considerably lighter that normal atmosphere. This makes appliance burner tip characteristics between the two fuels incompatible without further processing.

calculations are a theoretical construct.

**Q. Do you agree that the pressure support calculations are a theoretical construct?**

**A.** Yes, but I still disagree with the assumptions used by Mr. Normand to come up with the marginal cost of production capacity in this example, for the reasons stated above. The most significant error in Mr. Normand's theoretical construct is the assumption that new production capacity was needed in the year 2009. The impact of these errors and flawed assumptions on his calculation of the marginal cost of production capacity used in this rate design is not theoretical.

**Q. Do you believe an alternate proposal would have been more appropriate to determine a reasonable marginal cost of production capacity?**

**A.** Yes. I looked at two different LNG plant options. The first was from a marginal cost study done on behalf of EnergyNorth ten years ago by James Harrison in the National Grid NH revenue neutral rate redesign docket in DG 00-063. That LNG plant had a capacity of 6,300 Dth per day. The cost of that facility was significantly less than Mr. Normand's current alternative and the size of the facility would likely be a better fit almost anywhere in the National Grid NH system. However, the pricing data for that LNG peaker alternative is from 10 years ago. The second alternative uses as a more recent example of an LNG facility used in a marginal cost study done by Mr. Normand in 2008, on behalf of Bay State Gas Company. Mr. Normand provided a copy of this marginal cost study in response to data response ATT. Staff 1-167 (a) (*see* ATT. RJW-4). The plant capacity is 14,000 Dth per day, which is approximately half the size of Mr. Normand's propane alternative used in the National Grid NH marginal cost study in the instant docket. The marginal cost of this LNG alternative from the Bay State Gas Company study, priced in the same 2008 dollars as Mr. Normand's propane alternative used in this case, was $938.65, or 59 percent of the production capacity unit cost of Mr. Normand's choice for the National Grid NH study.

**Q Are there any other adjustments you recommend should be factored into your calculation of marginal cost of production capacity that differed from Mr. Normand's?**

**A.** No, keeping in mind the anticipated need for such a facility is many years into the future, my two adjustments to Mr. Normand's calculations, as described earlier in my testimony, achieve a lower cost estimate for production capacity.

**Q. Do you have any comments with the quality of data used in the marginal cost study?**

**A.** I have some concerns. In one example, Mr. Normand's calculation of marginal capacity related production expense used the same expense data for 2008 and 2007[16] (see Attachment PMN-3, page 11, lines 19 and 20, column 2). The Company's initial response to a Staff data request was that there was an error that would be corrected. In a later data response, the Company updated the capacity related production expense data for each year, from 2002 through 2008[17] and provided an updated EXCEL spreadsheet of the marginal cost study which reflected the corrections. In another example, I asked for an explanation for the large increases in Total General Plant Expenses in years 2007 and 2008 (*see* attachment PMN-3, page , line14, columns 2007 and 2008). In its initial response the Company said the numbers were incorrect, it was researching the cause and would make the appropriate corrections. With subsequent corrections, Mr. Normand's General Plant loading factor decreases from 6.25 percent to 4.78 percent[18]. These corrections have been incorporated into my adjustments to Mr. Normand's calculations,

16 Staff data response 1-171 (b).
17 Staff data response 3-49.
18 Staff Tech data response 3-19.

for purposes of determining marginal costs and class revenue requirements.

**Q. Do you have any other issues with Mr. Normand's marginal cost study?**

A. Yes, I have one additional issue. Attachment PMN-3, page 35 provides a summary of the marginal cost by component (i.e., customer-related and demand-related costs) and by rate class. The attachment shows that each cost component for certain rate classes has been adjusted upwards by a factor that represents the class uncollectible percentage. Such adjustments are inappropriate because the cost of customer non-payment is not a marginal cost. The cost to meet the demand of a new customer is independent of whether that customer pays his or her bill on time, or at all. Customer non-payment is a revenue collection issue and not a marginal cost issue.

**Q. Is Mr. Normand's use of the uncollectible percentage factor in this marginal cost study consistent with what was filed in DG 08-009?**

A. Yes. In DG 08-009, a colleague of Mr. Normand sponsored a marginal cost study using a similar uncollectable percentage factor adjustment to marginal cost by component. However, in his testimony from that proceeding, my colleague Mr. McCluskey raised this same issue that the inclusion of an uncollectable percentage factor is inappropriate in determining marginal costs. Mr. McCluskey pointed out that Mr. James Harrison, a colleague of Mr. Normand, in a marginal cost study he sponsored in the Unitil Energy Systems' base rate proceeding in DE 05-178, did not include these adjustments to marginal costs for the cost of non-payment.

**Q. Please summarize your conclusions regarding Mr. Normand's marginal cost study.**

A. Mr. Normand's marginal cost study should incorporate the adjustments and corrections I have described in my testimony. Specifically, in Attachment PMN-3, pages 1, 2, 3, 11, 20, 32, 34, 35, and 36, 37 and 38 of the marginal cost study have changed as a result of the updates described in my testimony and detailed in Attachment RJW-3. With these updates, I believe the marginal cost study provides sufficient support for changing rate class revenue requirements and redesigning rates in a manner that is consistent with results from the prior marginal cost study presented in DG 08-009. Based on my adjustments and corrections, the new total marginal annual revenue requirements are $65,376,241.[19] This will require an adjustment to total marginal revenue requirements of -$9,764,820, a 15 percent reduction, to match the estimated delivery revenue requirements of $55,611,421, as shown on my updated version of Attachment RJW-3, page 10, lines 1-4, column 12.

**Q. How does the adjusted total marginal revenue requirements describe above compare to Staff's alternate calculation using the present value calculation shown in Attachment RJW-4?**

**A.** Using the alternate long run unit cost of production capacity value of $535.75, the total marginal annual revenue requirement for delivery service was $65,455,818, which translated into a 0.12 percent variance from the result using the present value methodology embedded in Mr. Norman's model.

**Q. Mr. Normand proposed to cap the rate increase to the residential non-heat class at 150 percent and to any other rate class at 125 percent of the requested 23 percent overall increase. Is that proposal reasonable?**

**A.** The results of the marginal cost study suggest a less restrictive cap would allow the Company an opportunity to accelerate the elimination of the inter-class subsidies. However, that goal must be balanced with the impact on customer bills. A less restrictive

19 This amount replaces the $70,704,963 amount in Table 14 of the original marginal cost study in Attachment PMN-3, page 37, line 2, column 12.

cap could result in a rate increase for the residential heat customer class that substantially exceeds the proposed 28.5% increase to the delivery portion of those bills. The proposed limit to the maximum rate increase for the R-1 residential non-heating rate class is capped at 150%. Although the proposed higher cap is supported by the results of the marginal cost study, it is inequitable to single out this class of customers for a higher cap on the delivery rate increase. If the marginal cost to serve is to be the determining factor in setting class revenue requirements, then the same argument could be made for a higher cap on delivery rate increases for the C&I Large Load Factor rate classes G-54 and G-63. Specifically, using Mr. Normand's marginal cost results in Attachment PMN-RD-4-2, page 1, the R-1 cap of 150 percent results in maximum revenues (line 31) that are 63% of the marginal cost to serve (line 25). By instead using the 125 percent cap for R-1, the revenue target is 60 percent of the marginal cost to serve. This R-1 result compares favorably to the commercial and industrial high load factor G-54 and G-63 rate class results, where Mr. Normand does apply the 125 percent cap, the revenue targets are 48 percent and 72 percent, respectively, for the G-54 and G-63 marginal costs to serve. Therefore, based on the assumption that the Company's overall rate increase request is determined to be reasonable, I recommend that a 125 percent revenue cap be adopted for all rate classes.

**Q. Please explain how Mr. Normand's proposed class revenue requirements were developed.**

**A.** The method used by Mr. Normand to arrive at the proposed class revenue requirements is presented on Attachment PMN-RD-4-2, page 2 of 2. As noted above, bill impact considerations limited the maximum increase to the residential non-heat class to 34.56 percent, while the bill impact to each of the remaining rate classes was limited to a maximum increase of 28.8 percent. The differences between the adjusted marginal cost based revenue requirements and the maximum level of revenues allowed under the revenue cap were summed and then allocated on a pro-rata revenue basis to the rate classes whose rate increases were not affected by the revenue cap. If the process resulted in any rate class exceeding its maximum allowed increase, the unrecovered revenue requirements from those classes were allocated to the rate classes not constrained by the revenue cap. Then, if required, this process is repeated until the revenue requirement increase for each rate class is below the maximum level.

**Q. What are the percentage increases that resulted from Mr. Normand's process?**

**A.** Mr. Normand has proposed increasing the residential non-heat class by the maximum possible, 34.56 percent. His proposed increase in rates to the remaining residential classes is also at the maximum level possible, 28.8 percent. In addition, large commercial and industrial classes with load factors greater than 90 percent will effectively see the maximum increase, while the G-43 rate class will see an increase slightly below the maximum, at 27.12 percent. The remaining commercial and industrial rate classes will see rate increases ranging from 2 to 17 percent.

**Q. Do you support the proposed class rate increases?**

**A.** As I stated earlier, I will not support an increase to the residential non-heat class based on a 150 percent cap. Mr. Normand's proposal to limit the maximum rate increase for all classes except R-1 to 125 percent of the requested overall increase, using the above described process means that customers in the G-41 and G-51 rate classes, currently paying more than the marginal cost will not receive any rate relief. Customers served under the G-41 and G-51 rate schedules are currently paying 2.4 percent and 11.4 percent more than marginal cost.[20] To obtain a different result would require a less restrictive revenue cap, which, as noted above, would likely mean that the residential classes would experience even higher increases. That said, I recommend that the issue of rate relief to the G-41 and G-51 customer classes be revisited if the increase authorized by the Commission turns out to be substantially less than the requested rate increase.

## V. Rate Design

**Q. Please describe the Company's current rate structures.**

**A.** Most of the National Grid NH residential customers receive delivery service under Rate R-3 which is composed of a monthly customer charge, and a declining block delivery rate structure. In this rate structure, the initial block of therms each month is provided at a rate that is higher than the rate applied to all therms consumed in excess of that amount (i.e., the "tail block" amount). This rate structure is also used to provide service to the small commercial and industrial customer classes that use less than 100,000 therms annually, with the remaining classes billed under a flat rate structure.

**Q. Please describe how has Mr. Normand has proposed to re-design the Company's rates.**

**A.** Regarding increases in customer charges, Mr. Normand has proposed caps of 15 percent for the residential non-heat class and 50 percent for all other classes Because of the lower customer charge increase to the residential non-heat class, he proposes a 100 percent increase to that class' therm rates. Therm rate increases for the remaining residential classes will be around 10 percent, with all remaining classes experiencing increases that range from 1 to 36 percent. These rate design proposals, before applying

20 See Attachment PMN-RD-4-2, page 1, line 28.

the R-4 discount, mean customer charges will account for 46 percent of the proposed delivery service revenue requirement, up from about 41 percent currently. The percentage of therm revenues accounted for by the initial and tail block rates will be 33 and 21 percent, respectively, compared to current levels at 31 and 28 percent. Therefore, the net effect of Mr. Normand's rate re-design is to recover a greater portion of the total revenue through the customer charges and less through the volumetric therm rates.

**Q. What effect will Mr. Normand's proposal have on the Company?**

**A.** Monthly customer charges represent assured or almost assured revenue. This reduces economic risks of the Company's operations and provides more assurances of net income available to shareholders. The risks in question include weather variability; declining use per customer; and volatility in customer bills.

**Q. Mr. Normand contends that the proposed rate re-design is justified because the marginal distribution related investment costs are fixed and therefore more appropriately collected through fixed customer charges as opposed to volumetric charges. Before you comment on that argument, please explain what is meant by the statement: "distribution-related investment costs are incurred regardless of the volumes consumed."**

**A.** While Mr. Normand recognizes that investment in distribution-related facilities is driven primarily by changes in the design day demand of customers, he contends that once those facilities are built the costs are unaffected by the amount of gas actually transported by them. From this he concludes that it is more appropriate to collect the distribution-related investment costs through fixed customer charges, rather than through volumetric therm charges.

**Q. What does this mean for cost recovery?**

**A.** The Company's proposed rate design to recover more of the overall class revenue requirements through customer charges is most noticeable on the lower use residential heat class of customers. This can be seen in Attachment PMN-RD -4-5 pages 3 and 4, where residential heat customers will experience higher overall per unit costs during lower use months and lower overall per unit costs during the higher use months. This is not entirely new to heat sensitive, R-3 and R-4 customer classes, during non-heating seasons. This is apparent from Mr. Normand's typical bill analysis for residential heat customers, which shows the increase in the base rate portion of winter bills ranging from 50 percent for lowest-use customers to 12 percent for the highest-use customers. With the proposed overall increase at 23 percent, the bill impacts will be inequitable for many customers in the residential heat class.

As for the commercial and industrial customer classes, the higher customer charge is much less noticeable because of the higher loads. With the exception of the G-41 customer class, as seen in Attachment PMN-RD -4-5 pages 7-24, the higher customer charge seems to be absorbed across the spectrum of loads in each rate class.

**Q. In your opinion are customer charges proposed by Mr. Normand in his rate re-design reasonable?**

**A.** The monthly marginal customer costs and the proposed monthly customer charges are nearly equal for the residential heat rate classes while the monthly marginal customer costs for the commercial and industrial rate classes are substantially below the proposed monthly customer charges[21]. For the residential non-heating class, the monthly marginal customer charge remains well above the proposed monthly customer charge. As I explained earlier, there are three classes that are more susceptible to the proposed higher

21 See Attachment PMN-RD-4-2, page 2, lines 42-43.

customer charges, the R-3 and R-4 customer classes and, to a lesser extent, the G-41 customer class. The proposed rate design still reflects customer charges for the R-3 and R-4 classes that are below marginal customer costs.

**Q. Are you proposing that the R-3, R-4 and G-41 rate classes' customer charges should be lower?**

A. I believe the proposed R-3 and R-4 customer charges should be reduced slightly, coupled with higher recoveries in the R-3 and R-4 volumetric rates, designed with declining block rate structures. The variation in intra-class bill impacts could be further reduced by utilizing a flat rate structure. The reduction, however, is unlikely to be significant as long as the rate re-design shifts some of the increase in the customer charge back to the volumetric therm rate. I believe the proposed G-41 rate design could also be adjusted slightly in a similar manner as I proposed with the R-3 and R-4 classes.

**Q. Would a flat rate structure discourage greater gas consumption?**

A Yes. Declining block rate structures tend to promote greater usage, which, in turn, requires more investment in infrastructure to meet the increased load growth. However, if the tail block rate is at or above the marginal cost, setting the flat rate above this level simply to promote energy conservation will encourage customers to make economically inefficient decisions which in the long run lead to an increase in system costs.

**Q. Does this conclude your testimony?**

A. Yes.