STATE OF NEWHAMPSHIRE

PUBLIC UTILITIES COMMISSION

DG 12-001

In the Matter of:
EnergyNorth Natural Gas, Inc.
Investigation into Excess Capacity

Direct Testimony

of

George R. McCluskey

September 28, 2012

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

EnergyNorth Natural Gas, Inc.) Docket No. DG12-001
Investigation into Excess Capacity)

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 Assistant Director within the Electric Division responsible for Wholesale Electric Markets.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I am a utility ratemaking specialist with over 30 years of experience in utility economics. I rejoined the Commission in March 2005 after working as a consultant for La Capra Associates for five years. Before joining La Capra, 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 utility least cost plans and demand-side management programs. I have presented or filed testimony before state regulatory authorities in New Hampshire, Maine, Ohio and Arkansas and before the Federal Energy Regulatory Commission. A copy of my resume is included as Exhibit GRM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose is to present Staff's response to the pre-filed testimony of Elizabeth Arangio on behalf of EnergyNorth Natural Gas, Inc.'s ("ENGI" or "Company") dated April 24, 2012. Ms. Arangio's testimony was filed in response to the Commission's Order of Notice in this proceeding dated February 22, 2012, which opened an investigation into "EnergyNorth's projected supply/demand balance and whether it is prudent for EnergyNorth to plan to retain more gas supply capacity than it needs to meet forecasted design-day peak demands or whether EnergyNorth ought to take actions to reduce the excess." The question of whether ENGI has excess supply capacity and, if so, the prudence of planning to retain such excess were issues raised by Staff in testimony submitted in Docket No. DG 10-041, ENGI's 2010 Integrated Resource Plan (IRP).

Q. WHAT SPECIFIC ISSUES DID THE COMMISSION PINPOINT FOR THE ABOVE REFERENCED INVESTIGATION?

A. The Commission stated that the investigation will address:

1. The extent of the excess capacity, the calculation of which shall be based on the design-day planning standard approved in Docket No. DG 10-041 and the most recently completed design-day peak demand forecast appropriately adjusted for projected demand-side management programs.
2. The advantages and disadvantages of reducing or eliminating such excess including potential customer cost savings.
3. The alternatives for achieving the reduction in capacity.
4. The role of the Granite Ridge peaking contract in meeting peak-day demands.

Q. WHAT ISSUES DO YOU ADDRESS IN YOUR TESTIMONY?

A. I address all four of the issues identified in the Commission's order of notice.

Q. BEFORE YOU BEGIN YOUR CRITIQUE OF ENGI'S TESTIMONY, PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. My conclusions are as follows:

(1) The cost of gas purchased under the peaking contract with the Granite Ridge Power Plant has generally been below the cost of gas produced by Company-owned propane facilities.

(2) If the peaking contract with Granite Ridge is renewed, the Company will have more capacity than it needs to meet its design-day planning standard and its seven-day storage requirement.

(3) Renewing the Granite Ridge peaking contract will allow the Company to retire its Manchester and Nashua propane facilities while still meeting its design-day planning standard and seven day storage requirement.

(4) Retiring the Manchester and Nashua propane facilities is in line with the retirement of propane facilities by Northeastern natural gas utilities over the last decade.

(5) Retiring the Manchester and Nashua propane facilities will benefit customers economically through a reduction in gas costs.

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. My key recommendations are as follows:

(1) The Commission should direct the Company to renew the peaking contract with the Granite Ridge.

(2) Conditional on the renewal of the Granite Ridge peaking contract, the Commission should remove from rate base the un-depreciated investments in the Manchester and Nashua propane facilities, thus precluding the payment of a return on those assets.

(3) The Commission should allow the Company to recover any un-depreciated investment in its Manchester and Nashua propane facilities over a period of five years.

(4) The Commission should direct the Company to dispatch the new Granite Ridge peaking contract whenever it is economic to do so.

II. GRANITE RIDGE PEAKING CONTRACT

Q. THE ORDER OF NOTICE IN THIS PROCEEDING REQUIRES THE PARTIES TO ADDRESS, AMONG OTHER THINGS, THE ROLE OF ENGI'S PEAKING CONTRACT WITH THE GRANITE RIDGE POWER PLANT IN MEETING PEAK DEMANDS. PLEASE DESCRIBE THAT CONTRACT AND EXPLAIN WHY IT IS A FACTOR IN THIS PROCEEDING.

A. Granite Ridge is a natural gas-fired power plant located in Londonderry, NH. In 2001, ENGI entered into an agreement with the owners of that power plant that provides it with an option to purchase up to [redacted] MMBtu per day of Granite Ridge's firm gas supply but no more than [redacted] MMBtu during the peak months of December, January and February each year. The maximum daily gas supply to the plant is 130,000 MMBtu. In return, Granite Ridge receives a commodity payment for each MMBtu of gas delivered to ENGI plus a monthly demand payment that is independent of the volume of gas delivered.

The peaking contract benefits ENGI and its customers in two ways. First, it provides ENGI with a firm gas supply that can be used to meet a portion of the design-day demand not met with other available capacity resources. In other words, the contract provides reliability benefits even when the commodity cost of the gas exceeds the gas cost for the Company's marginal supply resource. Second, if the commodity cost of the Granite Ridge gas supply is less than the variable cost of ENGI's marginal supply resource, the option can be exercised to displace more costly supply resources and, in the process, reduce the overall gas costs to customers. Clearly, the first benefit is directly relevant to the determination of whether excess capacity exists on ENGI's system. The second benefit, as we will see, is relevant to the level of cost savings associated with reducing or eliminating excess capacity.

Q. HOW IS GAS COMMODITY UNDER THE GRANITE RIDGE PEAKING CONTRACT PRICED?

A. While the pricing has varied over the years, the most recent version of the contract had the price set at [redacted] as reported in the Platt's publication Gas Daily.[1] [redacted] Thus, if the variable cost of ENGI's marginal gas supply exceeds [redacted] on any day during the three month peak period, ENGI can exercise its option to purchase gas from Granite Ridge and displace some or all of the marginal supply.

Q. WHAT ARE THE DEMAND CHARGES UNDER THE PEAKING CONTRACT?

A. The monthly demand charges increase over time with inflation. The most recent level was approximately [redacted][2]

Q. YOU SAID THE PEAKING AGREEMENT PROVIDES ENGI WITH THE OPTION TO PURCHASE GAS DURING THE PEAK WINTER MONTHS WHENEVER IT IS BENEFICIAL TO DO SO. HOW OFTEN HAS ENGI MADE USE OF THAT OPTION?

A. ENGI purchased gas under the contract on thirteen separate days in 2003 and one day in 2004. Since that time, the option has not been exercised.

[1] Based on most recent confidential version of Natural Gas Peaking Agreement. Initial confidential version provided in response to Staff 1-3.
[2] See Winter 2011/12 Cost of Gas Filing, Schedule 5A, page 1.

Q. WAS THE GRANITE RIDGE GAS SUPPLY COMPETITIVE WITH THE COMPANY'S MARGINAL GAS SUPPLY DURING THAT PERIOD?

A. The Company claims that it dispatches its gas supplies in merit order to meet daily customer demands. This means supplies with the lowest variable costs are dispatched first followed by supplies that are progressively more costly until the daily demand is met. On cold days when demands are very high, there may be a need for all of the available supply resources to be dispatched including high cost propane. We know from the Company's records that during the period 2007 to the present propane was produced on 63 separate days.[3] On each of those 63 days, Staff compared the price of gas under the Granite Ridge contract to the variable cost of propane and found the cost of propane to be lower on only 9 days. See Exhibit GRM-2. That is, on the other 54 days propane was produced at a cost that exceeded the price that ENGI would have paid had it purchased gas under the contract. Moreover, on 26 of the 54 days that gas was produced uneconomically the difference between the cost of propane and the cost of gas under the contract was equal to or greater than $5/MMBtu. On several days the difference was as high as $9/MMBtu. In short, ENGI did not dispatch its resources economically on those 54 days and therefore did not minimize gas costs to consumers.

III. DETERMINATION OF SUPPLY/DEMAND BALANCE

Q. DID THE COMPANY DETERMINE THE AMOUNT OF EXCESS CAPACITY ON ITS SYSTEM, AS REQUIRED BY THE COMMISSION?

[3] Staff does not have daily propane production data prior to 2007.

A. Yes. The Company's claims that it has 180,233 MMBtu per day of firm gas supply and a design-day demand that varies from 137,200MMBtu in 2011/12 to 142,200 MMBtu in 2015/16. These quantities translate to an excess of gas supply capacity over demand in 2011/12 of 43,033 MMBtu or 31% of projected design-day demand for that year. In 2015/16, the excess is smaller but still significant at 38,033 MMBtu or 27% of projected design-day demand. See Exhibit GRM-3. Despite these quantities, the Company contends that it "does not have excess capacity in its resource portfolio."[4]

Q. DID THE COMPANY COMPLY WITH THE REQUIREMENTS OF THE COMMISSION'S ORDER OF NOTICE WHEN IT ESTIMATED DESIGN-DAY DEMAND?

A. Yes.

Q. BEFORE YOU RESPOND TO THE COMPANY'S CLAIM THAT IT DOES NOT HAVE EXCESS CAPACITY, PLEASE COMMENT ON THE CONCEPT OF DESIGN-DAY DEMAND.

A. The reliability planning standard recommended by the Company and approved by the Commission in Docket DG 10-041, ENGI's 2010 Integrated Resource Plan, requires the Company to have sufficient capacity resources on hand to meet the projected design-day demand of its firm customers.[5] Because the design-day demand is not a normal peak demand but a peak demand that occurs very

[4] See Pre-Filed Testimony of Elizabeth Arangio, page 7, line 1.
[5] The Commission approved the criteria for calculating the design-day demand proposed by the Company in Order No. 25,317, dated January 11, 2012.

infrequently and only under extreme weather conditions, having sufficient capacity resources to meet that standard necessarily results in a reasonable level of reliability for firm customers. Stated differently, the design-day demand standard approved by the Commission creates a capacity reserve that serves the purpose of reducing the likelihood that gas service will be curtailed due to weather-related increases in demand. Furthermore, because the size of this reserve is based on a calculation that seeks to balance the benefits of increased reliability with the costs of incremental resources, there is no compelling reliability argument for retaining capacity in excess of design-day demand.

Q. WHAT IS THE COMPANY'S RATIONALE FOR CLAIMING IT HAS NO EXCESS CAPACITY?

A. The Company contends that "when the realities of resource planning and procurement, the Commission's regulatory requirements, and the contractual and operational constraints under which the Company operates are taken into account, it is clear that the Company does not have an excess." However, the Company has not explained how these "realities" actually impact the determination of excess capacity.[6]

Q. WOULD THE EXCLUSION OF THE GRANITE RIDGE GAS SUPPLY ELIMINATE THE EXCESS?

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[6] See response to Staff 2-2, which is reproduced here as Exhibit GRM-4.

A. No, but it would reduce it. My calculations indicate that the excess would be reduced to two-thirds of its previous 2010/11 level and half its 2014/15 level if the supply were excluded. See Exhibit GRM-5.

Q. DO YOU ACCEPT ENGI'S STATEMENT THAT IT WOULD NOT BE ABLE TO RENEW THE CONTRACT AFTER IT EXPIRES?

A. No. I have already shown that the existing contract provided considerable value to ENGI in the form of enhanced reliability and the potential to lower gas costs. For this reason alone, Staff expected that the Company would make every effort to renew the contract. When we add to this the fact that Granite Ridge also received considerable value from the contract, and was ready and willing to renew it, Staff fully expected that the renegotiations on a new contract would be completed in time to have the renewed peaking supply in place for the 2012/13 winter period. Indeed, Granite Ridge's plant manager informed Staff that he had notified the Company as far back as May 2012 of his desire to renew the contract. He also informed Staff that despite several follow-up calls, the Company failed to respond to his offer to negotiate. That failure notwithstanding, the plant manager believes, even at this late date, that a good faith effort by the Company could result in a new firm gas supply for the upcoming winter and for the future.

Q. THE COMMISSION'S ORDER OF NOTICE CALLS FOR THE PARTIES TO ADDRESS WAYS TO ELIMINATE THE EXCESS. WHAT IS STAFF'S RECOMMENDATION?

A. Assuming the Company renewsl the Granite Ridge peaking contract, Staff recommends that after renewal the Company retire all of its propane production and storage facilities except those located in Tilton.[7] This would reduce firm capacity by about 32,000 MMBtu per day, leaving an excess of only 6,000 MMBtu per day. Staff considers this to be preferable to other options[8]because the commodity cost of the gas produced by the propane facilities almost always exceeds the commodity costs of other resources in the supply portfolio. Later in this testimony, I document in greater detail the potential cost savings to customers associated with the proposed retirement of the Manchester and Nashua propane facilities.

Q. HOW EXTENSIVELY HAVE THESE TWO FACILITIES BEEN USED IN RECENT YEARS?

A. Prior to the expansion of the Concord Lateral on November 1, 2009, it was common for gas to be produced by the Nashua and Manchester propane facilities on multiple winter days. In 2008, for example, those facilities produced gas on 28 separate days. In 2009 the number was 16 days. After the expansion of the Concord Lateral, the numbers for 2010 and 2011 were 4 and 6 days respectively. Moreover, if the Company had dispatched the facilities in merit order, the numbers for 2010 and 2011 would have been zero and 1 respectively. See Exhibit GRM-2.

[7] The Tilton propane facilities are required for distribution pressure maintenance purposes.
[8] Such as not renewing the Granite Ridge peaking contract.

IV. THE NEED FOR PROPANE FACILITIES

Q. THE COMPANY'S TESTIMONY INCLUDES THE CLAIM THAT RETIRING ANY OF ITS PROPANE CAPCITY WOULD NOT BE IN THE PUBLIC INTEREST. IT EVEN CLAIMS THAT THE PUBLIC INTEREST WOULD NOT BE SERVED BY RETIREMENT EVEN IF IT HAD SUFFICIENT PIPELINE CAPACITY TO MEET CUSTOMER DEMANDS. DO THE ACTIONS OF OTHER NATURAL GAS UTILITIES BEAR OUT THESE CLAIMS?

A. To the contrary, the available evidence indicates the exact opposite. That is, almost all natural gas utilities in the Northeast that had propane resources in their supply portfolios within the last ten years have elected to retire some or all of them. New Hampshire itself provides evidence of this trend. Northern Utilities, the only other natural gas utility in the state, recently elected to retire the only propane facility in its portfolio because of the high cost to make it compliant with relevant regulations and codes. As a result, the gas demands of Northern's customers are now being met, presumably reliably and at reasonable cost, without the aid of propane resources.

Other evidence of this trend relates to National Grid, the previous owner of ENGI. Since 2002, National Grid distribution companies or their predecessors have retired or made non-operational eight propane facilities with a total capacity of almost 100,000 MMBtu.[9] In each case, customer demands after retirement were

[9] In comparison, the capacity of ENGI's propane facilities is only 35,000 MMBtu.

met by increasing interstate pipeline capacity and/or on-system LNG vaporization capacity.

Nor is National Grid's experience unique. Northeast natural gas utilities as a whole have reduced the vaporization capacity of their propane facilities by [redacted] over the last ten years, from almost [redacted] in 2001/2 to less than [redacted] in 2011/12. See Exhibit GRM-6. Furthermore, only [redacted] gas utilities listed in the Northeast Gas Association's Winter 2011/12 report "Gas Supply Information for The Northeast Natural Gas Industry" have the capability to produce propane gas.

A reasonable interpretation of these data is that it is not necessary for Northeast natural gas utilities to have propane facilities in their resource portfolios in order to meet customer demands reliably and at reasonable cost. Those goals can and are being met with a combination of pipeline capacity and LNG capacity.

Q. TO YOUR KNOWLEDGE, WERE ANY OF THE ABOVE MENTIONED RETIREMENTS OPPOSED ON PUBLIC INTEREST GROUNDS?

A. No.

Q. WHY HAVE SO MANY PROPANE FACILITIES BEEN RETIRED OVER THE LAST DECADE?

A. Perhaps the best documented account of the retirement of propane facilities relates to the Yankee Gas Company in Connecticut. In 2009, Yankee proposed to regulators that it retire three of its four propane facilities "due to their age, their condition, and their impacts on customers." Specifically, Yankee argued that because the four propane facilities have been in service for more than 40 years and because they have been idle in recent years, as they have not been needed to meet peak-day supply requirement, their ability to reliably meet peak-day demands was uncertain. Also, Yankee argued that the cost of bringing the plants into compliance with existing safety and operating codes was determined to be greater than the cost of alternative supply options. As a result, Yankee asserted that it was in the best interest of customers to retire the plants and satisfy its supply needs through other peak-day supply options.

Northern Utilities also chose to retire its Portland, Maine facility because of the high cost to bring the facility back into operation.

Q. IN THE DOCUMENTS YOU REVIEWED, DID YOU COME ACROSS ANY SUPPORT FOR THE CLAIM BY ENGI THAT PROPANE FACILITIES HAVE SPECIAL CHARACTERSTICS THAT SUPPORT THEIR CONTINUED OPERATION?

A. On the contrary, the evidence points to propane facilities being a liability rather than an asset to utilities. The following passage from testimony submitted by the Director of Gas Systems Operations for Yankee Gas to Connecticut regulators supports this view:

> Propane-air plant operation and equipment maintenance requires skill sets and training programs that are substantially different than those required to operate a natural gas distribution system. Propane itself is characteristically different than natural gas, with different flammability ranges, chemical properties and leak

characteristics that make the product inherently more hazardous than natural gas. Aside from the distinct skill sets required for safe operation, concerns associated with vandalism, terrorism, equipment failures and interchangeability should all be considered in the risk assessment of propane peak shaving plants. In addition, logistical issues with trucking, inclement weather restrictions on tankers and numerous regional supply shortages over the last several years have made propane a less than ideal supply option.[10]

For all of these reasons, the Commission should reject ENGI's claim that retiring any of its propane capacity would be contrary to the public interest.

Q. WHAT ABOUT THE SPECIFIC CLAIM BY THE COMPANY THAT PROPANE PLANTS HAVE THE ABILITY TO BE DISPATCHED AT A MOMENTS NOTICE?

A. The responses to discovery on this question show quite clearly that the claim is false. The facilities are not fitted with remote control equipment and are not even staffed around the clock during peak periods. Instead, the Company m onitors weather forecasts during peak periods and determines the appropriate staffing requirements. Once a decision is made to produce gas at a particular facility, time is needed for the operators to prepare that facility for production.

V. SEVEN-DAY STORAGE REQUIREMENT.

[10] Testimony of Edna M. Karanian on behalf of Yankee Gas Services Company, March 2, 2009, Connecticut DPU, Docket Nos. 06-10-03 and 08-10-02.

Q. YOU HAVE SHOWN ABOVE THAT RETIRING THE MANCHESTER AND PROPANE FACILITIES WOULD REDUCE THE EXCESS CAPACITY BUT LEAVE THE COMPANY WITH SUFFICIENT FIRM RESOURCES TO MEET ITS DESIGN-DAY PLANNING STANDARD. WILL THAT OPTION ALSO ALLOW THE COMPANY TO MEET ITS SEVEN-DAY STORAGE REQUIREMENT?

A. Yes. Under the Commission's seven-day storage rule, the Company must maintain, between December 1 and February 14 of each year, an on-site storage capability which when combined with available pipeline supplies is sufficient to meet the estimated demand for gas on the seven coldest consecutive days.[11] In the most recent on-site storage report filed with the Commission, the Company estimated a design weather gas demand of 759,665 MMBtus of which 749,605 MMBtus would be met from available pipeline supplies, leaving 10,060 MMBtus to be supplied from on-site storage. See Exhibit GRM-7. This seven-day storage requirement is substantially less than the capacity of the Company's LNG and propane facilities, which currently stands at 110,868 MMBtus. While the retirement of the Manchester and Nashua propane facilities would reduce the on-site capacity to 53,539 MMBtus, it is still considerably higher than the seven-day storage requirement.[12]

[11] The seven coldest consecutive days is referred to as design weather conditions. The design weather conditions used by the Company is the actual observed weather for January 9 - 15,2004,

[12] Note that the on-site capacity of 53,539 MMBtus takes no account of the truckable LNG capacity that is permitted to be included under the seven-day storage rule.

Q. DID YOU ASSUME THAT THE GRANITE RIDGE PEAKING CONTRACT WOULD BE RENEWED WHEN YOU ESTIMATED THE AVAILABLE PIPELINE SUPPLIES UNDER DESIGN WEATHER CONDITIONS?

A. Yes. For the reasons stated above, Staff believes that a good faith effort by the Company will result in a new Granite Ridge firm gas supply that is beneficial to both parties. .

Q. DOES THE COMPANY DISPUTE THAT IT CAN MEET THE SEVEN-DAY STORAGE REQUIREMENT WITH THE MANCHESTER AND NASHUA PROPANE FACILITIES RETIRED?

A. At page 25 of Ms. Arangio's testimony, she states that the Company "would not be able to meet the requirements of the Commission's seven-day on-system storage requirement if [peaking] assets were retired without replacing them with other assets." Given my testimony above, Staff can only assume that her position is based on the assumption that the Granite Ridge contract would not be renewed. That is, it is reasonable to believe her position is that the Company cannot comply with the seven-day storage rule.if the Manchester and Nashua facilities are retired and the contract is not renewed. As noted, Staff's retirement recommendation is conditional on the renewal of the Granite Ridge peaking contract.

VI. COST SAVINGS

Q. WHAT ARE THE POTENTIAL COST SAVINGS ASSOCIATED WITH REDUCING THE EXCESS THROUGH RETIREMENT OF THE MANCHESTER AND NASHUA PROPANE FACILITIES?

A. Each year, the Company collects through its winter COG filing $1,980,428 of non-gas costs related to its LNG and propane production and storage facilities.[13] The $1,980,428 comprises in broad terms depreciation in the amount of $449,000; O&M in the amount of $876,000; and a tax adjusted revenue deficiency in the amount of $593,000. The annual cost saving to customers associated with retiring the Manchester and Nashua propane facilities should therefore approximate the propane-related share of these expense amounts. When asked to break down each cost into its LNG and propane components, the Company responded that it does not have the necessary accounting data and therefore cannot provide the requested information.[14]

Q. GIVEN THE COMPANY'S FAILURE TO PROVIDE THE REQUESTED INFORMATION, ARE YOU ABLE TO PRODUCE AN ESTIMATE OF THE COST SAVING TO CUSTOMERS?

A. Absent detailed accounting data that would allow an accurate calculation of the annual revenue requirements for the propane facilities, any estimate would necessarily be inexact. That said, starting with the $876,000 O&M expense and using the relative vaporization capacities for the LNG and propane peaking facilities, we estimate the annual O&M expense saving associated with the

[13] This quantity was agreed in settlement as part of the Company's last base rate case (Docket DG 10-017). See Appendix 1 to settlement agreement.
[14] See response to Staff 2-4, which is reproduced as Exhibit GRM-8 to this testimony.

retirement option to be in the region of $511,000. Turning to the $449,000 depreciation expense and using the relative net plant balances for the LNG and propane facilities, the annual depreciation expense saving could be in the region of $207,000. Finally, applying the same relative net plant balances to the $593,000 revenue deficiency, we estimate an additional annual cost saving of about $273,000, for a grand total of $991,000. The actual cost saving to customers, however, could be somewhat less due to the likelihood that the Commission would authorize the Company to collect over time any un-depreciated investment in the retired facilities on the ground that such investment was prudently incurred. Consequently, a reasonable estimate of the annual saving to customers associated with the retirements would be in the region of $784,000.

Q. IS SUCH AN ANNUAL COST SAVING LARGE ENOUGH IN YOUR OPINION TO JUSTIFY STAFF'S RECOMMENDED COURSE OF ACTION?

A. Absolutely. Since $784,000 represents approximately 1 percent of the total gas cost for 2011, it is clearly not an insignificant cost saving. Moreover, any amount that customers can avoid through good utility practice should not be disparaged.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.