New Hampshire Public Utilities Commission

EnergyNorth Natural Gas, Inc.
d/b/a Keyspan Energy Delivery New England

DG 07-101

Concord Lateral

Testimony of

John B. Adger, Jr. and Yavuz Arik

Q. Please state your names, occupations and business addresses.

A. My name is John B. Adger, Jr. I am a Senior Consultant with The Liberty Consulting Group. My business address is P. O. Box 1237, Quentin, Pennsylvania 17083.

My name is Yavuz Arik. I am a consultant to The Liberty Consulting Group. For this project, my business address is P. O. Box 1237, Quentin, Pennsylvania 17083.

Q. Please summarize your respective educations and professional experience.

A. Summaries of our respective educations and professional experience are attached as Exhibits JBA-1 and YA-1. Especially relevant to this proceeding is John Adger's recent experience serving as an extension of the Staff of the Connecticut Department of Public Utility Control (*DPUC*) for its consideration, and ultimate authorization, of a liquefied natural gas (*LNG*) based peaking facility that has just been completed and gone into service in Waterbury, CT. Mr. Adger worked with the DPUC through its initial consideration of a proposal by Yankee Gas Services Company to construct such a facility, which came during a rate case in 2001, through conditional approval in 2003 and final approval in 2004. In 2007, he assisted the DPUC in its consideration of the costs of the facility for inclusion in the Company's rate base.

Q. Have you previously testified in regulatory proceedings?

A. Both of us have previously testified in regulatory proceedings, including before this Commission. Lists of the proceedings in which each of us has testified are attached as Exhibits JBA-2 and YA-2.

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

A. We were engaged by the Commission to evaluate a proposal, made by EnergyNorth Natural Gas, Inc. (*ENGI*, or *the Company*), d/b/a KeySpan Energy Delivery New England (*KeySpan*), to enter into a contract with Tennessee Gas Pipeline Company (*Tennessee*, or *TGP*) for additional firm natural gas transportation service on the Concord Lateral segment of Tennessee's pipeline system.

The Concord Lateral extends from an intertie with Tennessee's main line at Dracut, Massachusetts, to the Company's city-gate receiving stations. With the exception of a small city gate at Berlin, NH, the Company receives all of its pipeline supplies by way of the Concord Lateral. The Concord Lateral serves only the Company's gate stations and an electricity-generating plant owned by Granite Ridge Energy, LLC and located at Londonderry, NH.

The proposed contract would provide for firm deliveries of up to 30,000 Dth/day to the Company's city gates. TGP has advised ENGI that providing the additional capacity would require it to install compression on the Concord Lateral, which would be provided by a new compressor station to be located near Nashua, NH. A map showing the locations of the Concord Lateral, the Company's gate stations, Granite Ridge Energy's generating station, and the new compressor station is attached to our testimony as Exhibit 3.

I. Summary

Q. Please summarize your testimony.

A. We reviewed the analysis that the Company presented in support of its proposal. We made some adjustments to that analysis based on our experience in similar evaluations in the past, then we used the adjusted analysis to evaluate whether the Company's proposal should be approved.

Our analysis shows that the Concord Lateral provides access to sources of peak-period supplies that the Company requires. We recommend that the Company be required to show that those supplies will be available on a firm basis at the inlet to the Concord Lateral on terms that are competitive with its on-system options for peaking supplies. On the basis of our experience in the New England natural gas Market, we believe that such a showing can be made, and thus that the Company's proposal to enter the TGP contract should be approved once the requisite showing has been made.

II. Discussion of the Company's Analysis

Q. Please proceed.

A. The Company's analysis presented in support of its proposal is developed in three parts:

- Company Witness John Stavrakas provides estimates of capital and operating costs for several on-system alternatives that the Company identified for comparison with its proposal.
- Company Witness Paul DeRosa then developed Mr. Stavrakas's capital and operating costs into annual revenue requirements for each alternative. Based on those revenue requirements, Mr. DeRosa calculated levelized unit costs which were then incorporated into an optimization analysis. The Company used the costs in its proposed contract with TGP as the revenue requirement for its proposal. (The capacity cost under that contract does not change for the life of the contract, which is 20 years. Commodity transportation charges, which are usually a small portion of the total, were agreed to be those applicable to TGP's general rate schedules.)
- Company Witness Ted Poe used a linear-programming computer model to determine which of the alternatives resulted in the lowest total costs to ENGI's customers in each of two selected years, Gas Years 2009/10 (November 1, 2009 through October 31, 2010) and 2011/12 (November 1, 2011 through October 31, 2012). Total costs were used as the "figure of merit", rather than the levelized

costs of the alternatives, in order that trade-offs between commodity costs and the costs of delivery capacity ("capacity costs") might be considered in the analysis.

The Company presented several on-system alternatives for comparison with its preferred alternative. Those alternatives were 1) a liquefied natural gas (*LNG*) facility without liquefaction capability, 2) an LNG facility with liquefaction, and 3) a propane/air facility. For purposes of analysis, the Company assumed that an LNG facility would be located on the same site as its existing LNG-based peaking facilities in Concord. Additional propane/air facilities would have to be split between the existing site in Concord and a new site in Nashua, NH, in order to meet the requirement for blending the propane/air mix with natural gas. (That requirement is a feature of this type of peaking resource.)

Q. And what did the Company find?

A. As reported in Ms. Arangio's testimony, the Company found that its proposal, namely entering into the contract with TGP, compares favorably to the range of alternatives available to the Company to meet its need for additional peaking supplies that was identified in its Integrated Resource Plan, submitted to the Commission in Docket No. DG 06-105.

Q. What concerns do you have with the Company's analysis?

A. We have identified concerns at each stage of the Company's analysis. In particular,

- Mr. Stavrakas's capital- and operating-cost estimates double-count some of the component costs for the on-system alternatives, making their costs seem higher than they really are.
- Mr. DeRosa's revenue-requirements estimates use values for several parameters that are inappropriate in our view, further increasing the apparent costs of the on-system alternatives.
- In Mr. Poe's optimization analysis, we found some methodological questions, which we have worked with him to address. We also found what we think is a questionable assumption: the costs of the Company's proposal are understated in our view because the Company is overly optimistic about the cost of peak-period supplies delivered to the inlet of the Concord Lateral during the winter months.

Q. What did you do to address your concerns?

A. With the assistance of the Commission's Staff, we have adjusted the Company's analysis at each stage. First, we eliminated (or at least reduced) the double-counting of capital and operating costs. Next, we selected cost-of-service parameter values that seem more in line with circumstances and regulatory practice in New Hampshire and then re-computed the levelized revenue requirements associated with each alternative. We then repeated the optimization analysis presented in Mr. Poe's testimony to see how the results would change when we substituted our values for the Company's.

We restricted our analysis to the LNG-with-liquefaction alternative. There are service-quality issues associated with the use of propane/air in some locations. The LNG-without-liquefaction alternative presents issues of access to and terms for the provision of LNG supply that could compromise its viability as an option. Examples of those issues include the following:

- Access to LNG supply: The Company's contracts for LNG supply limit the quantities available during peak winter months. During the extreme cold of January 2004, those limits impacted the Company's use of its LNG-based peaking facilities, forcing it into the spot market. The availability of sufficient trucks for transporting the LNG from a source to the Company's peaking facilities can be a binding constraint, also.[1]
- Terms for the provision of LNG supply: It is widely understood that providers of LNG give better prices for the product to customers who have their own liquefaction capability.

Q. What changes did you make to the inputs provided by Mr. Stavrakas?

A. We adjusted both his capital-cost estimates and his operation and maintenance (*O&M*) cost estimates. For capital costs, we asked Mr. Stavrakas to compare the costs that he had initially provided to the costs of the recently-completed LNG facility installed by Yankee Gas Services Company (*Yankee*) in Waterbury, CT. While Yankee's facility is larger than the one that was estimated for ENGI, it is similar in important ways. In particular, the Yankee facility was installed at a site that contained existing peaking facilities and operations, as ENGI's Concord site does. As such, the Waterbury facility is in a location

[1] Specific examples of the impact of these constraints were presented by Ms. Arangio in her response to a Data Request (No. Staff 2-4) in Docket No. DG 04-152

that has adequate capacity to move regasified LNG out into the distribution system (this capacity is often referred to as "take-away" capacity) without a need for extensive modifications to the distribution system. The Concord location is similar in that respect.

Exhibit 4 to our testimony, which is the Company's response to Data Request No. Staff 3-11a, shows the results of the comparison. While the categories of cost are difficult to compare directly, one category stands out. That category is Company Overheads. Exhibit 4 suggests that ENGI's overheads are over three times as large as Yankee's.

We simply do not believe that ENGI's overheads are that much larger than Yankee's. ENGI is a subsidiary of a much larger company, and thus must bear an appropriate share of that larger company's sharable costs, but so is Yankee.[2] We believe that the reason for the dramatic difference is that ENGI is counting as overheads some costs that are also in the other categories. To remove that double-counting, we adjusted Mr. Stavrakas's capital-cost number down by the difference between the two figures for overheads ($8.45 million).

We also found some double-counting in Mr. Stavrakas's estimates of O&M costs. Discussions in our technical sessions with the Company revealed that the estimate that he started from[3] in preparing his Exhibit JSS-1 already had insurance costs in it. Since Exhibit JSS-1 adds in insurance costs, those costs are double-counted. Exhibit JSS-1 also

[2] Yankee is a subsidiary of Northeast Utilities, parent company of Public Service Company of New Hampshire.

[3] The referenced estimate is a budget for O&M costs at a similar facility that KeySpan has at Haverhill, MA. That budget was submitted in this proceeding as an attachment to Data Request No. Staff 3-13.

includes a line-item for Annual Taxes. Discussions in technical sessions revealed that those were property taxes. Property taxes are added separately in Mr. DeRosa's revenue-requirements model, so those costs are double-counted, also. To correct for the double-counting, we reduced Mr. Stavrakas's basic O&M cost estimates from $2.04 million per year to $1.05 million.

Mr. Stavrakas's O&M costs had another assumption that seems incorrect. Liquefaction equipment is typically powered by electricity. Mr. Stavrakas's O&M costs for the LNG-with-liquefaction alternative include an allowance to pay for that electricity. Discussions in the technical sessions revealed that he had included an allowance for electricity sufficient to liquefy half of the contents of the tank every year. In fact, because the facility is a peaking facility, and thus is used relatively sparingly, his estimate is probably too high. There is "boil-off", where a certain amount of the LNG vaporizes as it is stored, but that phenomenon would not reduce the tank's contents by half in each year.[4] Allowing for some use of the facility in meeting the Company's requirement for peaking supplies, we have cut Mr. Stavrakas's estimate for this cost in half, from $0.33 million per year to $0.17 million per year. Our allowance represents a requirement to liquefy one-quarter of the contents of the tank every year.

Q. What about Mr. DeRosa's revenue-requirements estimates?

[4] The boil-off rate is determined by the thermal characteristics of the containment facility. Old tanks have higher boil-off rates than new ones, for example, and facilities with similar construction have similar boil-off rates. The estimated boil-off rate for the new Yankee Gas facility in Waterbury is 18 percent per year. That figure should be a fair estimate for a facility at Concord, as both would be new and of similar design and construction.

A. Several of the parameters used by Mr. DeRosa for his calculations seem inappropriate. In particular,

- Economic life: Mr. DeRosa used a depreciable life of 30 years, whereas Yankee's facility in Connecticut is being depreciated over 40 years.
- Costs of capital:
  - Equity: Mr. DeRosa used a equity rate of return of 10.39 percent after income taxes, whereas recent awards by this Commission have been closer to 9.30 percent.
  - Debt: Mr. DeRosa used an annual interest rate for long-term debt of 7.55 percent, whereas the Company has recently agreed to a rate of 5.8 percent.
- Return on rate base: Mr. DeRosa used year-end rate base to calculate return on rate base, whereas New Hampshire practice is to use average rate base.
- Property-tax rates: Mr. DeRosa's calculations used a rate of $19.20 per $1,000 of assessed value. In response to a Staff Data Request[5], he reported that the current rate is $17.50 per $1,000.

Q. What changes did you make to those parameters?

A. We changed them to values that seem appropriate to a facility constructed and operated in New Hampshire, located in Concord:

- Economic life: 40 years
- Cost of capital: Equity, 9.30 percent return; long-term debt, 5.8 percent per year
- Return calculated on average rate base

[5] Data Request No. Staff 3-34.

- Property-tax rate: $17.50 per $1,000 of assessed value.

Q. How much difference did those changes make?

A. We adjusted the capital and O&M costs, and Mr. DeRosa's parameters, as noted, and then re-ran the revenue-requirements model that Mr. DeRosa used in preparing his testimony. With our changes, the levelized unit cost of the LNG-with-liquefaction alternative declined from $1.206 per MMBtu/day of capacity to $0.713. A spreadsheet detailing our calculations is attached to our testimony as Exhibit 5.

Q. What about Mr. Poe's optimization model?

A. Mr. Poe's optimization model takes the specified prices and quantities of all of the Company's available gas-supply resources as inputs, and then selects from among them that combination of resources that satisfies demand at the lowest total cost. This function is performed simultaneously for all 365 days of the selected years. Operations like storage injection and withdrawal are specified as constraints that affect certain supply resources. As noted earlier, the years that he selected for analysis were the "gas years" (November 1 through October 31) 2009-2010 and 2011-2012.

All of the potential alternatives for the required incremental peaking capacity were made available as options in Mr. Poe's optimization analysis. Each was specified to the model as a unit capacity cost, which was developed by Mr. DeRosa with his revenue-requirements model using capital and operating costs provided by Mr. Stavrakas. Mr. Poe also specified commodity costs to the model, so that it could pick the combination of options, existing and new, that resulted in the lowest overall total gas-supply costs for each year. We substituted the levelized unit capacity costs for the LNG-with-liquefaction alternative that we computed for the costs that Mr. Poe used for that option, and then we re-ran the optimization.

Q. Did you make any changes to other inputs to the model?

A. Yes, we made three other changes. First, we had to lengthen the life of the Company's preferred alternative, the proposed contract with TGP for additional capacity on the Concord Lateral, to enable a proper comparison with our LNG-with-liquefaction alternative. The proposed contract is a 20-year contract at a negotiated rate. We assumed that, at the end of the 20 years, the contract would revert to a Z6-to-Z6 contract like the one that the Company added in 2003/2004, and thus would be priced on a rolled-in basis pursuant to the terms of TGP's FERC Gas Tariff. The current reservation rate for Z6-to-Z6 transportation is \$0.1039 per MMBtu/day of capacity.[6] We used the contract rate for the first 20 years, then we escalated today's Z6-to-Z6 rate by 0.5 percent per year from today for Years 21 through 40, then we discounted the entire stream back to present value using the same discount rate (7.93 percent) as was applied to our LNG-with-liquefaction alternative. This calculation resulted in a reduction of the unit rate for the Company's proposal, from \$0.400 per MMBtu/day to \$0.338. Details of the calculation are presented in a spreadsheet attached to our testimony as Exhibit 6.

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[6] Source: Company response to Data Request No. Staff 1-7, Attachment A. Shippers also pay a commodity rate of \$0.0663 per MMBtu shipped, plus fuel of 0.89%

Q. What about the other two changes?

A. One of those changes involved natural gas prices at the Henry Hub, which is the location in Louisiana where the futures contract traded on the New York Mercantile Exchange (*NYMEX*) settles. The other change involved "basis", which is the observed difference in price between gas available at the Henry Hub, and gas delivered to any market-area delivery point, in this case to the inlet of the Concord Lateral, near Dracut, MA. Industry publications report daily and monthly prices for gas at the Henry Hub, and daily prices for gas at Dracut.

Q. Please describe the changes that you made.

A. For gas prices at the Henry Hub, Mr. Poe started with the annual averages forecast for the years of interest by the U. S. Department of Energy's Energy Information Administration and published in its *Annual Energy Outlook* (*AEO*), dated February, 2007. He then converted that one number for each year into a series of monthly prices by using the pattern of monthly prices that was observed during the Gas Year 2002-2003.[7] That year was used because it included a design winter in terms of the number of enhanced degree-days (*EDDs*) experienced.

We found that prices are currently available for NYMEX futures contracts that will deliver gas in each of the months of interest for the analysis. Thus, we substituted the

[7] As reported in the Company's response to Data Request No. Staff1-19, the conversion was accomplished by multiplying the AEO price by the ratio of each month's 2002-2003 price to the average for that year.

closing prices for those contracts observed on January 3, 2008, for the prices used by Mr. Poe.

We also made a conforming change to the propane prices specified to the model. The AEO publication does not provide a propane price, but the model requires one because several of the Company's existing peaking facilities use propane/air, and propane/air is one of the possible choices for new peaking capacity. Mr. Poe had observed that propane prices bear a reasonably-consistent relationship to crude-oil prices on a per-gallon basis. Thus, to get a propane price, he took the AEO forecast for the price of crude oil in the years of interest, and multiplied it by a conversion factor developed from the historical relationship between crude oil prices and propane prices. He then developed the resulting annual-average propane price into monthly prices using the pattern of monthly prices observed in Gas Year 2002-2003. Again, we found that crude oil prices are available from the NYMEX for the months of interest. We used the NYMEX crude oil prices with Mr. Poe's conversion factor to get more-current propane prices. A spreadsheet listing the prices that we used is attached to our testimony as Exhibit 7.

Q. What about the change involving basis?

A. The Company's proposed alternative requires gas delivered to the inlet of the Concord Lateral, as does one of its current gas-supply resources. Accordingly, prices at that location (Dracut, MA) are required in order to run the model. For this input, Mr. Poe added $2.30 per MMBtu to the Henry Hub price during the winter months (November through March), and $0.60 per MMBtu during the summer months (April through

October).[8] The Company reported that these basis differentials are consistent with its experience in its recent requests for proposals (*RFPs*) for gas supplies delivered to the Dracut location.[9] The Company also suggested that $2.30 per MMBtu over the Henry Hub price would cover the cost of incremental gas-supply projects that it is currently discussing with the sponsors of those projects.[10]

Our concern is that, while the $2.30 per MMBtu number may be appropriate for "base-load" supplies, *i.e.*, supplies taken at a high load factor, it is not representative of the differentials that would be likely under the market conditions that are likely to prevail at a time when the gas supply being considered here would be required; *i.e.*, during periods of peak demand.

Q. Please explain your reasoning.

A. The Company provided a copy of its RFP, and of its summary of the proposals that it received in response to its RFP, in response to one of our data requests.[11] Our review of the summary suggested that the offers for base-load volumes were priced with respect to the Henry Hub, but that "swing" quantities, *i.e.*, the component of the Company's requirement that varies daily, with one exception were priced with respect to market-area

[8] These values were used for Mr. Poe's "Constrained" Case, representing a market for transportation capacity in the Northeast U. S. that has insufficient capacity during peak periods. He also developed basis differentials for an "Unconstrained" Case, wherein additional transportation capacity was added; he ultimately did not use that case.

[9] In response to a request during the technical session on December 3, 2007, the Company provided a copy of its RFP for gas supply for the winter of 2007-2008, plus its analysis of bidders' responses, as a supplement to its response to Data Request No. Staff 2-24.

[10] See the Company's response to Data Request No. Staff 4-4.

[11] This material was provided as a supplement to the Company's response to Data Request No. Staff 2-24.

points, either Dracut or TGP Zone 6. In other words, bidders for the swing quantities made no commitments regarding the basis differential. Thus, whatever the differential is on the day that ENGI requires swing supplies, the price charged for that day's supplies will include that differential.

In an effort to assess whether $2.30 per MMBtu is a reasonable number for use in this part of the analysis, we collected daily basis data over the past five years. That data is presented in Exhibit 8 attached to our testimony. The data suggests that the daily basis between Henry Hub and either Dracut or TGP Zone 6 is around $0.50 per MMBtu except on cold winter days when it goes much, much higher. In fact, it is those peak winter days when the gas supplies at issue here would be used. Thus, we conclude that the $2.30 per MMBtu number is much too low to be applied to the peaking supplies that are an important aspect of this analysis.

Q. What value should be used for basis on those days?

A. It happens that, during the month of January 2004, ENGI not only operated its existing peaking capacity, but it also went into the spot market to supplement its available peaking supplies. Thus, those spot-market purchases could be considered to occupy the same position in ENGI's dispatch order as the capacity that would be added here.

The gas-market conditions at the time those spot-market purchases were made should be similar to the conditions being experienced when the proposed incremental capacity would be required. Thus, the basis differentials observed at that time should be indicative of what they would be when the incremental capacity would be called on. Although the basis differential went as high as $57 during that month,[12] the weighted average basis differential for ENGI's spot purchases in that month was $11.927 per MMBtu. Today's basic gas prices are higher than they were in 2004, and today's oil prices are much higher than they were in 2004. Since $11.927 is a value that has been observed, however, we used it for supplies delivered via the incremental capacity in our analysis for Gas Year 2009/2010.

Q. Are spot-market purchases the proper analog for peaking supplies delivered to the inlet of the Concord Lateral?

A. We do not believe that any supplier is going to take basis risk for a few days' supply.[13] Thus, we believe that any supply delivered to Dracut for only a few days per year is going to be priced at Dracut. ENGI can contract for a purchase option at Dracut, in order to limit the supply-reliability risk associated with a purely spot-market transaction. The price of that option would be in the form of a reservation fee for the capacity required. Commodity delivered under the option would be priced at the point of delivery, *i.e.*, Dracut or TGP Zone 6, rather than at some upstream point.

Q. What happened to the model results when you used the different basis?

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[12] Source: Company response to Data Request No. Staff 1-21.

[13] ENGI's analysis indicates a possible shortfall on only 12 days during Gas Year 2009-2010, increasing to 26 days during Gas Year 2011-2012. See the Company's response to Data Request No. Staff 1-18.

A. We tested the higher basis as a surcharge on the incremental Concord Lateral capacity. For 2009-2010, the optimization model still picked the Concord Lateral over our LNG-with-liquefaction alternative.

Q. What about the later gas year?

A. When we re-ran the model with 2011-2012 gas prices and the 2004 basis differential, the model still picked the Concord Lateral option. For that year, we also tested even higher basis differentials. At $16.927 per MMBtu ($5 per MMBtu, or about 40 percent, higher than what was experienced in January 2004), the model split the requirement between the Concord Lateral and our LNG-with-liquefaction alternative. At $21.927 per MMBtu, the model continues to split the requirement, but more of it would be supplied by the LNG.

III. Conclusions

Q. What do you conclude from your analysis?

A. We conclude that, for the period of interest for this analysis, if peak-period supplies are available on a firm basis at Dracut for an average premium of $12 per MMBtu or less over the Henry Hub price, then those supplies are the most cost-effective solution to ENGI's peaking problem at the present time. On the basis of recent experience, the $12 premium should be sufficient for non-firm supplies, especially if the growth in gas supplies coming into New England exceeds the growth in peak-period demand. The question is, what additional cost would be incurred to ensure that the supply is firm?

On the basis of our experience in the New England natural gas Market, we believe that the Company can ensure that the supplies are firm in several ways. One way mentioned above is capacity options. We expect that capacity options would be available both on a monthly basis and on a daily basis. Another way to ensure firm supplies is to contract for a firm, delivered peaking service. We expect that a number of companies operating in the New England Market would offer one or more of these services. The question is the price.

IV. Recommendations

Q. What do you recommend?

A. We recommend that the Company be required to show that firm peaking supplies can be made available over the next five years at Dracut at a price that would not upset the comparisons that we made in our analysis. In other words, the cost of the firm peaking supplies would not result in a weighted average cost for those supplies of more than $12 over the Henry Hub price. If the Company can make such a showing, and we believe it can, the Company's proposal to enter into the contract with TGP should be approved.

The Concord Lateral is not a resource that the Company can use to meet its requirements for peaking capacity. Rather, it provides access to potential sources of peaking capacity that are in addition to the Company's existing on-system peaking plants. Questions regarding the Company's longer-term options for meeting its growing requirement for peak-period capacity remain to be addressed.

If the Company's peak continues to grow at the rate indicated in the materials filed in this proceeding,[14] the Company will require additional peaking capacity six years after this expansion of the Concord Lateral goes into service. Given the lengthy nature of facility siting and approvals processes, consultations to support the possible development of on-system options should begin soon. We recommend that the Company address these issues as part of its Integrated Resource Planning process.

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

A. Yes, it does.

[14] See, *e.g.*, the Company's response to Data Request No. Staff 2-21.