BEFORE THE
STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: ISSUANCE OF ADVISORY OPINION TO	)	
ENERGY FACILITY SITING BOARD (EFSB)	)	Docket NO. 22-42-NG
APPLICATION TO CONSTRUCT	)	
LNG VAPORIZATION FACILITYON	)	
OLD MILL LANE, PORTSMOUTH, RHODE	)	

PRE-FILED DIRECT TESTIMONY OF JEFFREY LOITER
FILED ON BEHALF OF THE TOWN OF MIDDLETOWN

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Jeffrey Loiter. My address is 11 Tracy Lane, Shelburne, Vermont 05482.

Q: By whom are you employed?

A: I am employed by the National Association of Regulatory Utility Commissioners as a Technical Director, but in this proceeding, I am acting as an independent consultant on behalf of the Town of Middletown.

Q: Please summarize your work relevant to your role in providing testimony in this docket.

A: I hold a bachelor's degree in Civil and Environmental Engineering from Cornell University and a master's degree in Technology and Policy from the Massachusetts Institute of Technology. I have over 20 years of experience in environmental policy, energy, and utility regulation. In previous consulting roles I became a trusted policy advisor and expert witness for advocacy groups, state consumer advocate offices, and energy efficiency advisory councils in three states, covering topics including integrated resource planning, cost-effectiveness and the economics of energy efficiency, and the available potential for efficiency.

Q: Have you previously testified before the Rhode Island Public Utility Commission or the Energy Facility Siting Board?

No. In my previous positions I have submitted written testimony and/or testified before public utility commissions in Arkansas, Kansas, Kentucky, Maryland, Ohio, Virginia, and West Virginia.

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

A: My testimony will address the following issues:

1. Whether or not the proposed Aquidneck Island Gas Reliability Project ("Project") is necessary.
2. Other technically feasible solutions that are available at reasonable cost.
3. Suggested actions and strategies that may be preferred to the Project.

II. THE FACILITY IS NOT NECESSARY AS A PERMANENT SOLUTION

Q: Have you reviewed the application materials related to this project?

A: Yes, I have. Rhode Island Energy (or "Company") has applied for a license to construct and operate a facility to store liquified natural gas ("LNG") and to vaporize LNG and inject in into the distribution system on Aquidneck Island. As described in the Aquidneck Island Gas Reliability Project Siting Report ("Siting Report"), the Company claims the Project is necessary to address both a capacity vulnerability and a capacity constraint in the Distribution System serving Aquidneck Island (Siting Report, p. 8).

The Company states that the capacity vulnerability results from the fact that its customers on Aquidneck Island are served solely by one pipeline at one delivery location in Portsmouth, creating a single point of failure (Siting Report, p. 9). The capacity constraint is a result of the projected design day gas demand exceeding the Company's contracted pipeline capacity (Siting Report, pp. 10-11).

The Siting Report notes that the Company's analysis of the need for Project was influenced by the January 19, 2019, gas outage on Aquidneck Island, which resulted in a state of emergency for over 7,000 customers. (Siting Report p. 8). The Company has also stated that the Project, or "some version of the Project" will be required as long as it serves gas heating customers on Aquidneck Island. (Porcaro testimony, p. 8). The Company's message is, in effect, "without this project we could have a repeat of the January 2019 event." The Company states that the Project is consistent with the recommendations of the Rhode Island Division of Public Utilities and Carriers (Division) to meet areas of need, as stated in its Investigation Report Into the Aquidneck Island Service Interruption on January 21, 2019. [1]

Q: What is your understanding of the cause of the 2019 gas outage?

A: As described in the Division report and reported by the Pipeline and Hazardous Materials Safety Administration (PHMSA), the January 2019 event was the result of three factors, all of which were necessary in order for the low-pressure condition and ultimate loss-of-service to occur. One of these factors was customer demand that exceeded forecasts and contracted gas supply on the pipeline system serving Aquidneck Island. The other two factors can best be described as operational failures: a programming error at a metering and regulating station and multiple equipment failures (including the failure of an uninterruptible power system) at a permanent LNG storage and vaporization facility (Division's Investigation Report, pp. 4-5). The level of customer demand was not by itself the cause of the outage, nor would the outage have resulted if only one of the two

1 http://www.ripuc.ri.gov/eventsactions/AI_Report.pdf.

operation failures had occurred in addition to the high demand. This conclusion is reinforced by the fact that there have been several years when the facility was not in operation without incident or gas-shut offs as occurred in 2019. (Response to Middletown 1-3).

Q: The proposed Project would address the possibility of future failures of this type, though, correct?

A: Correct, but it is also true that future disruptions could be avoided by reducing or eliminating the possibility of three simultaneous detrimental conditions, only one of which is exogenous to the gas system and beyond the control of human operators. The Project may be necessary in the short term to address the identified capacity deficit on Aquidneck Island, but there exist other strategies to avoid complete disruption of gas supply other than the permanent installation of the facility on Old Mill Lane.

III. OTHER TECHNICALLY FEASIBLE SOLUTIONS ARE AVAILABLE AT REASONABLE COST

Q: Have you reviewed the alternatives related to this Project?

A: Yes. The Siting Report and Company witnesses' pre-filed direct testimony to RIPUC describe and discuss alternatives to the Project, ultimately concluding that none of them are preferable to the LNG facility on Old Mill Lane. The alternatives can be grouped into three major types: expansion of pipeline service to Aquidneck Island, alternative locations for seasonal or permanent LNG vaporization capacity, and non-infrastructure solutions.

The Company rejected the possibility of constructing additional pipeline infrastructure to address the capacity vulnerability due to the difficulties of permitting new pipeline infrastructure and the long lead-time for construction that would necessitate several years of seasonal LNG mobilization in the interim) (Siting Report p. 33).

Q: How does investing in new natural gas infrastructure compare with Rhode Island's energy and climate goals?

A: Rhode Island's climate-related goals for reductions in greenhouse gas emissions suggest that additional investments in natural gas infrastructure run the risk of becoming stranded assets. The Rhode Island state legislature has set mandatory targets for greenhouse gas emissions reductions. As codified in the 2021 Act on Climate, "greenhouse gas emissions shall be ten percent (10%) below 1990 levels by 2020, shall be forty-five percent (45%)

below 1990 levels by 2030; eighty percent (80%) below 1990 levels by 2040, and shall be net-zero emissions by 2050."[2]

Q: What about alternative locations for LNG vaporization?

A: I do not have a position on the Company's analysis of those locations, because non-infrastructure alternatives are, in my opinion, a better solution.

Q: What non-infrastructure solutions has the Company analyzed?

A: The Company has provided several different analyses and discussions of non-infrastructure solutions to meeting gas demand on Aquidneck Island. These include: 1) The Aquidneck Island Long-Term Gas Capacity Study (September 2020), 2) the Portable LNG Vaporization Project Siting Report submitted to the EFSB (May 2021), 3) the previously-mentioned Aquidneck Island Gas Reliability Project Siting Report submitted to the EFSB (April 2022), and 4) pre-filed direct testimony submitted to the RIPUC in this docket. For the most part, I will focus on the alternatives as presented in the April 2022 Siting Report.

The analysis of non-infrastructure alternatives included four scenarios compared against a baseline of the proposed Old Mill Lane Project, referenced as "Seasonal LNG Trucking" in the report. Notably, the Company assumes that the baseline scenario consists of their proposed solution (the Project) plus a moratorium on new gas connections.

Q: Is there currently a moratorium on new gas connections?

A: No, there is not. As a result, the "baseline" to which all of the alternatives are compared represents a situation that is not, in fact, the current situation on AI.

Q: How does that assumption affect the analysis of alternatives?

A: The Company assumes that a moratorium on new gas connections would result in all new load choosing to heat with oil. Because heating with oil produces more GHG emissions than heating with gas, the moratorium results in greater GHG emissions than allowing new customers to heat with gas. (Siting Report, p. 42). That is, assuming a false baseline consisting of a moratorium, the Company presents their preferred alternative consisting of the Project and the *absence* of a moratorium as reducing GHG emissions.

2 R.I. Gen. Law §42-6.2-9

Q: But is the Company's stated need for the project based on the presence or absence of a moratorium on new gas connections?

A: No, it is not. The presence or absence of a moratorium only affects the forecast of peak day and peak hour gas demand, which in turn affects the amount of efficiency, demand response, and electrification that would be needed to address the forecast deficit in peak day and peak hour capacity.

Q: How would changing the baseline definition change the results presented by the Company?

A: The Company's preferred alternative to operate the Old Mill Lane facility and not implement a moratorium would not result in any GHG emissions savings.

Q: What is the reasoning behind the Company's assumption that a moratorium would result in new load being served by oil and therefore cause an increase in GHG emissions as compared to not having a moratorium?

A: The Company states that "electrification is not a cost-effective heating option" and that "a majority of households in southeast RI currently use fuel oil for home heating."

Q: Do you have any response to those statements?

A: The second assertion is simpler to address because it is irrelevant. In the face of technological advancement and growing awareness of the climate crisis, the heating equipment choices of home-owners and home-builders in the past, dating in many cases back ten, twenty, or more years, has no bearing on the choices of today's home-owners and home-builders.

With respect to whether or not electrification is cost-effective, there are two factors to consider: up-front cost and on-going operational costs. The Company did not provide an analysis of the up-front costs of heat-pump heating vs. natural gas heating. There are also a variety of equipment types (e.g., furnaces vs. boilers, central heat pump vs. ductless mini-split) and scenarios under which to assess costs (e.g, new construction vs. existing construction, different home sizes), making it difficult to say that either heat-pumps or gas heating is less expensive in all situations. In addition, cost estimates for gas heating systems typically do not also include the cost of cooling systems; the cost of heat-pump systems covers both heating and cooling.

Q: Has the relative cost of installing heat pumps vs. gas heating changed recently?

A: Absolutely. The Inflation Reduction Act includes both tax credits and up-front rebates for heating electrification. Tax credits of up to $2,000 are available for heat pumps. For households in the 22% tax bracket, this credit represents pre-tax savings of approximately $2,500. Although high-efficiency furnaces are also eligible for tax credits up to $600, the IRA has clearly shifted the relative costs of gas and electric heating. Medium and low-income customers can save even more with up-front rebates on the purchase of heat pumps available through the High Efficiency Electric Home Rebate Act (HEEHRA). Medium-income customers can receive rebates for 50% of the cost of heat pumps, up to $8,000 per home; low-income customers may be eligible to receive rebates of 100%, eliminating any out-of-pocket costs for heating electrification.

For operational costs, the Company's response to Middletown Data Request 2-2 states that heat pump heating systems will have "roughly ten percent higher" costs than for a gas heating system based on average prices in 2021. With this small difference, an individual ratepayer may or may not consider heat-pump heating "not cost-effective," particularly given the climate benefits and access to cooling that heat pumps can provide. Some customers in Rhode Island are choosing to install electric heating even when gas is available. Participants in Rhode Island's Residential New Construction Energy Efficiency program have increasingly selected electric heat over gas heating, choosing electric heating by more than a 3 to 1 margin in 2021.[3]

Q: So, is the Company's assumption that all customers would choose oil-fired heating in the presence of a moratorium reasonable?

A: No, I do not think it reflects the realities of customer behavior. While it is unlikely that all customers would choose electric heating if gas were not available, it also unlikely that all customers would choose oil heating in that situation. The reality lies somewhere in between those extremes.

Q: Returning to the Company's analysis of alternatives…can non-infrastructure solutions address the capacity constraint?

A: Yes. The Company's response to CLF Data Request 1-3 clearly states "Non-infrastructure solutions provide relief from capacity constraint but not capacity vulnerability."

Q: What are these alternatives?

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3 *2022 Annual Report*, Rhode Island Energy Efficiency and Resource Management Council, June 2022. http://rieermc.ri.gov/wp-content/uploads/2022/07/eermc-2022-annual-report-final-6-16-22.pdf.

A: The non-infrastructure alternatives consist of three major components: energy efficiency, demand response, and heating electrification. The energy efficiency component focuses on reducing the energy consumption of buildings through weatherization (e.g., improvements in air sealing and insulation) and incremental improvements in HVAC system efficiency. The demand response component of this solution involves customers reducing the amount of natural gas that they consume over a specific period of time, typically for either a few hours or a whole day. In this case, the demand response program is limited to non-residential customers. The heating electrification component involves encouraging customers to choose electric heat pumps to replace existing gas-fired heating systems when they reach the end of their useful life. [4]

Q: Do these alternatives solve the forecasted capacity constraint on Aquidneck Island?

A: Yes. As described in the Siting Report, non-infrastructure solutions that address the capacity constraint are feasible both with and without a moratorium on new gas connections. Both would allow the Company to retire the Old Mill Lane site after the 2029/30 season (Siting Report p. 37).

Q: How do the costs of these alternatives compare with the Company's proposal?

A: It depends on how you look at them. The Siting Report presents the cost to the utility of the non-infrastructure solutions as "undiscounted" estimates. That is, costs are not assumed to increase from today's estimates, nor are costs incurred in the future discounted based on consumers' and the states' preference for consumption now versus in the future. The Company states that undiscounted costs are used "to aid in comparisons of costs among options." (Siting Report, p. 37, footnote 20). The costs estimates are $143 million without a moratorium and $100 million with a moratorium

Q: Does the Company's decision to not discount these cost estimates aid in comparisons among options?

A: No, it does not, nor is not discounting future costs in keeping with utility practices, state guidance, and good economics. Utilities earn a rate of return on their investments that is based in part on the cost of capital, whether through debt or equity. Providers of capital demand a return on the money they provide, based in part on risk and part on their preference for a dollar today over a dollar tomorrow. Rates of return typically range between 8% and 12%, a substantial portion of which reflects the time value of money.

4 New installations of heating equipment in new construction would also be targeted for electrification, but this represents a small percentage of the total, as new home construction on Aquidneck Island is small compared to the existing building stock.

There is clearly a difference between spending a dollar on a project this year and spending a dollar on a project five years from now. In contrast with the Company's statement, using undiscounted cost estimates when the timing of those costs is different hinders the comparison of costs, rather than aids them. Thankfully, the Company does provide discounted cost estimates in footnotes. Using a real discount rate of 5.43%, the non-infrastructure solution without a moratorium costs $86 million; with a moratorium the cost is $63 million. [5]

Q: How do those compare with discounted costs of the Company's preferred alternative?

A: The proposed project is stated to cost $15 million for capital expenditures and $1 million for annual operational costs. Because the capital expenditures would occur within a year of approval, discounting will have little to no effect on that estimate. The annual operations costs would be lower in each future year as a result of discounting. Assuming the same discount rate as the Company uses in the footnotes, operating the project for seven years (from the 2023/24 season through the 2029/2030 season) would have a net present value of approximately $5.7 million, making the total discounted present value of the Project $20.7 million. In contrast with the $128 million difference in undiscounted costs between the non-infrastructure alternative without a moratorium and the Company's preferred alternative (i.e., the project), the difference between the discounted costs of non-infrastructure solution with a moratorium and the preferred alternative is roughly $42 million.

Q: That still seems like a big difference. Are there other ways of comparing the costs of the various alternatives?

A: Yes, there are. To begin with, considering only the cost to the utility ignores the bill savings that accrue to customers who reduce their consumption through energy efficiency investments. In response to Middletown Data Request 3-3, the Company estimates that customers would save approximately $3 million between now and 2030 and $8.6 million between now and 2035.[6]

Q: Are there other costs or benefits that can be considered when comparing the project alternatives?

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5 Siting report, p. 37, footnotes 20 and 21. The Siting Report indicates that the discounted values are based on a discount rate of 7.54% and an inflation rate of 2%. This translates to a real discount rate of 5.43%.

6 These are undiscounted values. Using the Company's real discount rate of 5.43%, the savings are $2.1 million through 2030 and $5 million through 2035.

Yes. Rhode Island uses a cost-effectiveness test to assess the relative economic impact of energy efficiency, system reliability, and other energy system investments. The "Rhode Island Cost Test" is an economic analysis that aligns the calculation of costs and benefits with the state's policy goals.

Q: How is it different than the cost estimates provided by the Company?

A: The Company's estimates only reflect the costs that they would incur to implement each of the alternatives. It does not include any costs borne by ratepayers or taxpayers. It also does not include the benefits that accrue to the public from reduced consumption of natural gas. It is unclear whether or not it includes the cost savings to the utility from reduced gas consumption from efficiency efforts.

Q: Are those all included in the Rhode Island test?

A: Yes, they are. Interestingly, the Rhode Island Strategic Electrification Study prepared for the Company in December 2020 by an outside consultant did use the Rhode Island test to assess the cold-climate heat pump market and pathways for heat pump adoption. [7] The test was also included in the Aquidneck Island Long-Term Gas Capacity Study that the Company prepared in September of 2020. [8]

Q: What are the results of the Rhode Island test when applied to the non-infrastructure alternatives?

In response to discovery, the Company provided the results of the Rhode Island test for the project alternatives.[9] The net costs of the non-infrastructure solution as compared with the baseline are $7.8 million with a moratorium and $5.2 million without a moratorium. These are net costs relative to a baseline of the both the proposed project and a moratorium on new gas connections. The net cost of the Company's preferred solution, without a moratorium, is negative $12.6 million (that is, a net benefit), due to the avoided additional costs and avoided greenhouse gas emissions of natural gas heating as compared to the oil-fired heating that is assumed to occur in the presence of a moratorium. As I noted earlier, I do not think that this assumption is completely valid. Any amount of customer-selected electric heating in the face of a moratorium would decrease the benefits of the Company's preferred alternative and decrease the net costs of the non-infrastructure alternative without a moratorium. Regardless, the difference

7 http://rieermc.ri.gov/wp-content/uploads/2021/01/rhode-island-strategic-electrification-study-final-report-2020.pdf

8 https://www.nationalgridus.com/media/pdfs/other/aquidneckislandlong-termgascapacitystudy.pdf

9 Middletown Data Request 3-4, Table 1

between the Company's undiscounted costs of $143 million for the non-infrastructure alternative and a net cost $5.2 million using the Rhode Island test is striking.

Q: What are the greenhouse gas emissions impacts of the various alternatives?

A: The proposed project and the alternatives result in differences in greenhouse gas emissions resulting from several factors. Emissions are avoided by reducing gas consumed for heating and through energy efficiency. Emissions are added from generating electricity for electric heating. In the Company's analysis, greenhouse gas emissions are increased in the presence of a moratorium on new gas connections, based on the assumption that new customers would choose oil-fired heating in the absence of gas availability, on which I have previously commented.

Q: Are there other potential sources of greenhouse gas emissions?

A: Yes. Natural gas is composed primarily of methane, a potent greenhouse gas. Climate scientists developed the concept of Global Warming Potential (GWP) to allow direct comparisons of the climate impacts of different gases. The GWP of carbon dioxide is the basis for comparisons, so its GWP is 1. As shown in the Siting Report, methane's GWP is 84.[10] This means that emitting 1 ton of methane is equivalent to emitting 84 tons of carbon dioxide.

Q: Did the Company's analysis consider emissions of methane?

A: Only partially. The Company's calculations include estimates of methane leakage from the distribution system on Aquidneck Island, which are assumed to be proportional to total gas consumption. But the Company asserts that the proposed project itself will not be a source of any emissions. (Olney testimony, p. 4)

Q: Is that a reasonable assumption?

A: No. For the years when the project would be in operation regardless of which alternative is implemented, it is true that there should be no differences in greenhouse gas emissions from the facility. That is, because all solutions require the facility through the 2029/2030 season (both the Company's preferred solution and the non-infrastructure solutions), there should be no difference in emissions through that timeframe. After that date, when the non-infrastructure solutions obviate the need for the facility, any emissions associated

10 Siting Report, p. 42, Table 4-2.

with the facility's existence and operation would be greater under the Company's preferred alternative.

Q: What are the emissions associated with the facility's existence and operation after 2030?

A: The Company has acknowledged that methane will be released from the facility under a number of conditions, including initial cool down of the storage equipment and offloading of LNG from transport trucks.[11] The Company estimates that between 300 and 330 MCF of methane could be released as a result of these operations annually.[12]

Q: Do you have any other comments or findings related to the Company's assessment of non-infrastructure alternatives?

A: Yes, I do, a very important one. The Company's estimates of costs. benefits, and GHG emissions are based on calculations through the 2034/2035 heating season.[13] As a result, I believe that the forecast GHG emissions reductions that would result from the non-infrastructure alternatives are underestimated. The non-infrastructure alternative results in long-term and in some cases permanent reductions in gas consumption. Efficiency measures designed to reduce the heating load of homes and businesses through weatherization and air-sealing typically have a useful life of 15 years or more. Such measures implemented during the period between 2023 and 2030 would continue to save energy and therefore reduce emissions well beyond 2035. Electrification efforts, which contribute the majority of savings in the non-infrastructure solution, would result in permanent reductions in gas usage, with attendant GHG savings well beyond 2035, until such time as a "baseline" estimate would assume the elimination of all emissions related to natural gas usage. Furthermore, the results of the Rhode Island test, to the extent that they were only calculated through the 2034/2035 season, will underestimate the value of avoided gas consumption and avoided GHG emissions. It is entirely possible that extending the analysis to capture the full lifetime of the investments in the non-infrastructure solution would result in the small net cost becoming a net benefit.

Q: You have explained different ways of looking at the relative costs and benefits of the alternatives to the Project. You have provided additional information about the potential for GHG emissions not assessed by the Company. Do you have any thoughts about the interaction of these?

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11 Response to Middletown Data Request 2-6b (labeled in the response as 'a').
12 Response to Middletown Data Request 3-2.
13 See, for example, Siting Report p. 43 and Olney testimony, p. 3 line 21 through p. 4 line 2.

A: Yes, I do. I think it is important to consider the relative costs and relative GHG savings together, rather than separately, particularly in light of the State's climate goals. Using the discounted utility cost estimates and the GHG emissions reported in Company Witness Olney's testimony, I have calculated the cost per ton of GHG emissions reductions resulting from the Company's preferred alternative and the non-infrastructure solution that solves the capacity constraint, both with and without a moratorium. I have also added the net present value of the $1 million annual operating cost of the Project to the Company's $15 million capital cost and the additional avoided GHG emissions related to the methane emissions from Project that I described earlier. The results are shown in the table below. Note that for this comparison, I am using the Company's baseline definition.

Alternative	Company's Preferred - No moratorium	Non-infrastructure Solution - with moratorium	Non-infrastructure Solution – No moratorium
Utility Cost ($ millions)	$21	$63	$86
Avoided GHG (thousands tons CO2e)	44.8	76.4	194.9
Cost of avoided CO2e ($/ton)	462	825	441

Q: What do you conclude from this analysis?

A: I think the important conclusion is that while the non-infrastructure solutions are more expensive in absolute terms, they also reduce carbon emissions by substantially more than the Project. On a cost per ton avoided CO2e it is actually slightly less expensive assuming no moratorium. This would seem to be a desirable outcome with a positive effect on the State's climate goals.

IV. PREFERRED SOLUTIONS

Q: Based on your analysis, you are recommending that the non-infrastructure solution that solves for the capacity constraint is preferable to the Company's project?

A: Yes.

Q: What about the capacity vulnerability?

A: As I stated earlier, the DPUC and PHMSA investigation into the January 2019 gas shut-off found that excess demand was only one factor, insufficient by itself to have caused the event. Rather than attempting to address the capacity vulnerability with more on-island gas supply, the Company should consider other ways of ensuring reliable service to Aquidneck Island. The Division's investigation did recommend winter deployment of

LNG facilities on Aquidneck Island, but as only one of eleven recommendations (Division's Investigation, Section 8.2, p. 67). Other recommendations included improvements in gas long range planning, initiation of demand response initiatives, emergency response planning, and establishing a process for emergency mobilization of LNG, among others. Developing a capability for emergency mobilization of LNG so that it could be deployed quickly in the event of a supply disruption could have benefits throughout the Company's system, not just on Aquidneck Island. Extreme weather events are typically forecast many days in advance, which could allow for staging of equipment to address potentially dangerous supply disruptions, much the way electric utilities deploy utility service trucks to areas in advance of severe weather that might result in downed power lines. Developing this capability would avoid the costs and community impacts of the permanent facility at Old Mill Lane. I will also note that the Company is aware of the potential need for portable LNG equipment during AGT's proposed expansion of the G-2 pipeline crossing of the Sakonnet River.[14]

Q: What do you suggest the PUC provide the EFSB in its Advisory Opinion?

A: I think it is important to recognize that the state's climate goals will almost certainly require a dramatic reduction in the use of natural gas for residential and commercial space and water heating. Some analyses of the most likely pathways to a decarbonized future suggest that these uses will need to be completely eliminated. Investing in MORE natural gas infrastructure at this time is inconsistent with these pathways, even if a complete transition away from natural gas is many years in the future. The limited geographic area served by this project provides an excellent opportunity to demonstrate how that transition can occur. The non-infrastructure solution described by the Company should be preferred over the permanent reliance on the Old Mill Lane facility.

Another recommendation from the Division's report on the January 2019 event was to investigate the feasibility of sectionalizing the distribution system on Aquidneck Island. While the intent of this recommendation was to provide flexibility in dealing with disruptions in gas supply, there may be ways to combine this effort with plans to gradually transition the Island away from natural gas. Investments in sectionalizing the system could also support gradually reducing the number of customers and geographic areas served by gas in a coordinated, planned fashion, rather than through piecemeal, customer-by-customer efforts. In this case, a small investment might result in cost savings in the long run.

Q: Please summarize the conclusions you have provided.

14 Response to Middletown Data Request 2-4a.

A: My conclusions are as follows. First, that the proposed facility is not necessary as a permanent solution to the capacity vulnerability and capacity deficit on Aquidneck Island. Second, that the Company's analysis of non-infrastructure solutions suffers from flaws in the calculation of the relative costs and benefits as compared with the Project. Third, the non-infrastructure solution is superior considered in light of the state's climate goals and with the correction of the analytical flaws, and therefore should be pursued in order to minimize the time during which the facility is needed to address the capacity deficit.

More broadly, rather than evaluate this proposal and this project in isolation, I encourage the PUC and the EFSB to considered it in the larger context of Rhode Island's energy and decarbonization goals. Gas usage on Aquidneck Island is just one aspect of a complicated and evolving energy system. Addressing the capacity deficit and ensuring reliable gas service to the Island must be solved as part of a comprehensive strategy to achieve broad public policy goals.

V. CONCLUSION

Q: Does this complete your testimony?

A: Yes, it does.