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January 26, 2023

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 22-42-NG – Issuance of Advisory Opinion to EFSB re RIE Application to Construct an LNG Vaporization Facility on Old Mill Lane, Portsmouth, RI Responses to PUC Data Requests – Set 1 (Full Set)

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company (the "Company"), I have enclosed the Company's responses to the Public Utilities Commission's (the "Commission") First Set of Data Requests (Full Set) in the above-referenced docket.

Thank you for your attention to this matter. If you have any questions, please contact me at (401) 709-3351.

Sincerely,

George W. Watson III

Enclosures

cc: Docket 22-42-NG Service List

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate were electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Heidi J. Seddon

January 26, 2023
Date

Docket No. 22-42-NG – Needs Advisory Opinion to EFSB regarding Narragansett Electric LNG Vaporization Facility at Old Mill, Portsmouth, RI
Service List update 12/20/22

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PUC 1-1

Request:

Please confirm the witness is using the term "renewable energy credits" to mean NEPOOL GIS Certificates (Certificates) associated with a facility certified as eligible to meet Rhode Island's Renewable Energy Standard. If not, please explain.

Response:

Yes, in his Pre-filed Direct Testimony, Company Witness Tyler Olney uses the term "renewable energy credits," or "RECs," in reference to Certificates eligible to meet Rhode Island's Renewable Energy Standard.

Prepared by or under the supervision of: Tyler Olney

PUC 1-2

Request:

It is PUC's staff's understanding that EC4 emissions accounting is currently an annual, Certificate-based accounting method. Does the witness agree or disagree?

Response:

EC4 uses a consumption-based approach to estimate a comprehensive inventory of total greenhouse gas ("GHG") emissions attributable to Rhode Island each year. Under this approach, relevant energy consumption in that year is multiplied by a relevant annual emissions rate for that year. As described by EC4, applying this methodology to electricity consumption involves subtracting Rhode Island's load served by renewable energy certificates ("RECs") from the state's total electric consumption to determine the state's remaining consumption served by the system mix of New England in a given year, which is then multiplied by an effective emissions factor for the system mix of New England in that year based on U.S. Energy Information Administration data.[1] Company Witness Tyler Olney agrees that EC4 emissions accounting is "annual" and "Certificate-based" insofar as emissions are estimated annually and RECs are netted out of electricity consumption emissions.

[1] *See* "Updates to Electricity Sector GHG Accounting"; available at: https://dem.ri.gov/sites/g/files/xkgbur861/files/2022-11/Updates%20to%20Electricity%20Sector%20GHG%20Accounting.pdf.

PUC 1-3

Request:

Please provide an explanation of how the witness is using the term "marginal emissions rate" generally.

Response:

The term "marginal emissions rate" is used in the same manner that it is used in the Avoided Energy Supply Costs in New England 2021 study ("2021 AESC") to estimate the impact on emissions of marginal changes in electricity consumption.[1] The forecasted marginal emissions rate, as defined in the 2021 AESC, is the difference in hourly forecasted emissions associated with Independent System Operator-New England ("ISO-NE") electricity demand divided by the difference in hourly forecasted ISO-NE electricity demand between a baseline scenario and a scenario with increased demand-side management measures. In effect, this value estimates the impact of marginal changes in electricity consumption on the total emissions associated with generation that serves the ISO-NE region.

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[1] The Avoided Energy Supply Costs in the 2021 AESC is utilized by Rhode Island for monetizing the benefits of utility demand-side management programs to determine cost effectiveness. The 2021 AESC is available at: https://www.synapse-energy.com/project/aesc-2021-materials.

PUC 1-4

Request:

Please provide an explanation of how the witness effectuated "marginal emissions… with an adjustment to account for the Renewable Energy Standard...".

Response:

In the analysis of Company Witness Tyler Olney, Mr. Olney took the short-run marginal emissions rates found in the Avoided Energy Supply Costs in New England 2021 study ("2021 AESC") and adjusted them by the percent of increased relative energy consumption that would be offset by Renewable Energy Certificates, which is assumed to be the same as the cumulative impact of the Renewable Energy Standard ("RES") for a given year. This methodology is consistent with the instructions on estimating long-run marginal emission rates in the 2021 AESC.[1] The table below lists the relative adjustment (i.e., "Relative Modeled Emissions") applied to the 2021 AESC marginal emissions.

Although the marginal emissions rate may not change in an amount equivalent to the change in the RES over time, a more precise projection of that impact would require complex modeling of the future energy system that would be costly and time consuming to perform. Instead, the potential impact of the RES is accounted for in a manner similar to the assumption made by EC4 for greenhouse gas emissions inventorying.

Table 1-4.1. Annual RES Targets and Subsequent Relative Adjustment to Marginal Emissions

Param.	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Incremental RES[2]	1.5%	4.0%	5.0%	6.0%	7.0%	7.0%	7.5%	8.0%	8.5%	9.0%	9.5%	9.5%

[1] *See Long-run marginal emission rates* subsection of Chapter 8.3 of the 2021 AESC.
[2] *See* R.I. Gen. Laws § 39-26-4.

Prepared by or under the supervision of: Tyler Olney

PUC 1-4, Page 2

Cumulative RES	19.0%	23.0%	28.0%	34.0%	41.0%	48.0%	55.5%	63.5%	72.0%	81.0%	90.5%	100.0%
Relative Modeled Emissions	81.0%	77.0%	72.0%	66.0%	59.0%	52.0%	44.5%	36.5%	28.0%	19.0%	9.5%	0.0%

Prepared by or under the supervision of: Tyler Olney

PUC 1-5

Request:

Please provide an explanation of how a time- or seasonal-based marginal emissions rate is consistent with the EC4's use of an annual, Certificate-based emissions methodology, which applies an average annual emissions rate to consumption not associated with a Certificate retired for a statutory or voluntary claim in Rhode Island.

Response:

For Rhode Island's historic emissions inventory, the "average annual emissions rate" EC4 uses is calculated from United States Energy Information Administration data of actual historic emissions associated with generation in the ISO-NE region for a given year. As noted in the Pre-filed Direct Testimony of Company Witness Tyler Olney, it is important to acknowledge that there is a distinct difference in the purpose of the EC4 greenhouse gas ("GHG") emissions accounting and the GHG emissions analysis presented in Mr. Olney's testimony that necessitates some variation in estimation methods. The EC4 analysis is a bottom-up quantification of all emissions on a historic basis and thus relies on actual emissions data. The GHG emissions analysis presented in Mr. Olney's testimony estimates the projected future GHG emissions impacts of different potential solutions to meet peak heating demand in the winter, which are presented relative to one another in a top-down quantification. Given this more specific purpose, it is appropriate to consider marginal emissions during periods of winter peak demand as that is more reflective of the relative impact of different solution options towards meeting winter peak heating demand on Aquidneck Island.

To further illustrate why this approach to estimating future emission impacts is appropriate, consider an example where electric demand had been much higher in the winter of that particular year. If this were to occur, the average annual emissions rate would not necessarily be the same. Rather, the average annual emissions rate would change to reflect the impact of greater use of marginal electric generator units and associated fuel (e.g., gas-fired or oil-fired combustion). That is to say, the change in emissions associated with a change in electric demand would not be strictly equal to the change in electric demand times the average annual emissions rate. In practice, the increased electric demand would need to be served by some marginal generator unit available at the time of increased demand. This aligns with the seasonal-based marginal emissions rate used in this analysis.

Prepared by or under the supervision of: Tyler Olney

PUC 1-6

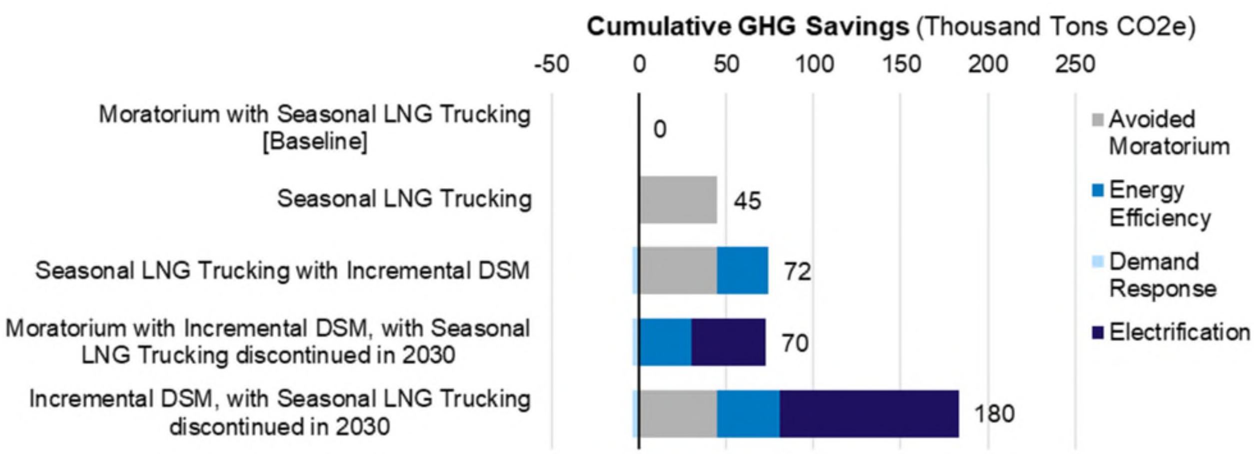
Request:

Please provide the analysis of alternatives using the methodology of a marginal emissions rate with an adjustment to account for the Renewable Energy Standard, but replace the marginal emissions rate used in the previous analysis with an appropriate annual average system residual mix emissions rate. Please explain how the annual average system residual mix emissions rate used in the analysis was determined.

Response:

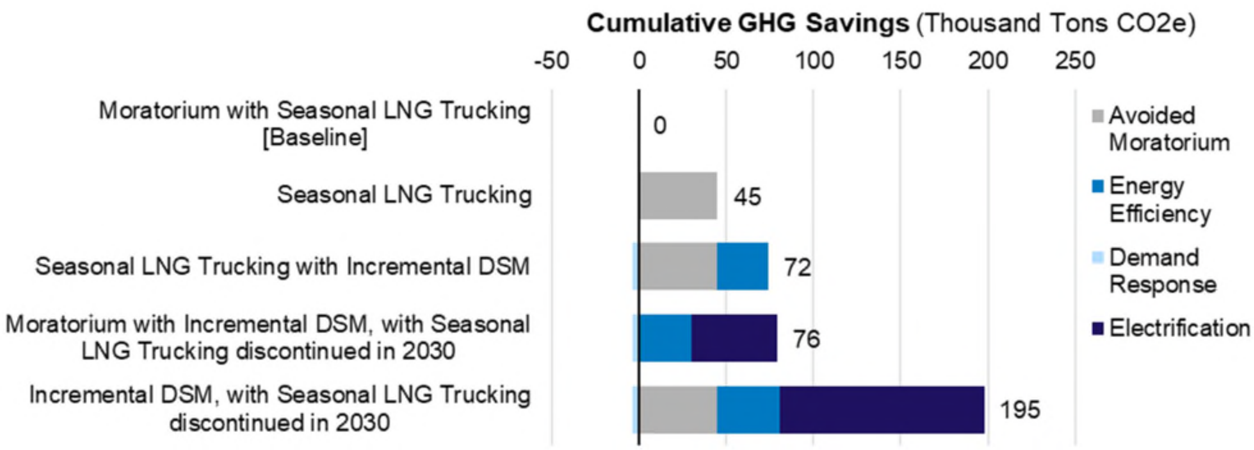
Figures 4 and 5 from the Pre-filed Direct Testimony of Company Witness Tyler Olney are updated, below, to apply the average electric emissions rate for ISO-NE forecasted in the Avoided Energy Supply Costs in New England 2021 ("2021 AESC") study in lieu of the marginal electric emissions rate. This average electric emissions rate is the total electric emissions forecasted in ISO-NE for each year divided by the total electric demand in that year, which were both sourced from the 2021 AESC.

Updated Figure 4. Cumulative GHG Savings with Higher Grid Emissions, without RES (Applying Average Electric Emissions Rate in Lieu of Marginal Electric Emissions Rate)



PUC 1-6, Page 2

Updated Figure 5. Cumulative GHG Savings with Higher Grid Emissions, with RES (Applying Average Electric Emissions Rate in Lieu of Marginal Electric Emissions Rate)



Prepared by or under the supervision of: Tyler Olney

PUC 1-7

Request:

Why does the baseline assume a moratorium on new gas connections when there is currently no moratorium on new gas connections and further, that is not the Company's proposed solution?

Response:

The Energy Facility Siting Board ("EFSB") Order No. 150 instructed the Company that its analysis should assume (i) a scenario with a full moratorium and (ii) a scenario where there is no moratorium (see EFSB Order No. 150 dated September 17, 2021, Page 35). For the purpose of the analysis, the full moratorium was selected as the baseline because the demand would be fixed at present levels.

Prepared by or under the supervision of: Tyler Olney

PUC 1-8

Request:

On page 6 of Olney's Testimony, the following statement is made:

Note again that for all alternatives there are no emissions impact directly from the Project (i.e., Portable LNG operations). Even in the alternatives in which the Project is discontinued in 2030, there are no additional GHG savings from avoided Project operation. Again, that is because the Project is not expected to be utilized in normal operation, because it is only utilized in the event of an upstream system disruption that would have otherwise caused system shutoffs.

a. Does this mean the expectation is that the facility will never run? If not, please explain.
b. If the answer to 1-8.a is no, please explain how the GHG analysis would be affected by the expectation that the facility will run at some point.
c. If the answer to 1-8.a is yes, how does this affect the needs analysis? Please explain.

Response:

No. The expectation is that, in normal weather years, the facility would only need to run to serve customer demand in a contingency scenario such as an upstream disruption (i.e., to address the capacity vulnerability, as described in Section 2.3.1 of the April 2022 Siting Report). The facility could also be necessary under extreme cold weather conditions driving design day-like demand (i.e., to address the capacity constraint, as described in Section 2.3.2 of the April 2022 Siting Report).

For the purpose of the greenhouse gas ("GHG") analysis presented in the Pre-filed Direct Testimony of Company Witness Tyler Olney, the likelihood of either or both of these conditions leading to some level of portable LNG operation at this facility over the analysis period was not estimated. If it is assumed that portable LNG operation will be necessary, the impact on the results of the GHG analysis would depend on whether it is necessitated by a system disruption or a weather event and when in the analysis period the event occurred. The table below lists the impact in these cases. In summary, portable LNG operation would lead to increased emissions in each scenario at a similar level, though solutions with incremental demand-side management ("DSM") would have relatively more emissions savings.

Table 1-8.1. Impact on GHG Analysis of Portable LNG Operation by Cause

	Upstream System Disruption	**Extreme Cold Conditions**
Early in Analysis Period (<2030)	Upstream disruption necessitates portable LNG operation under all solutions, yielding no difference to relative emissions presented here.	Increased heating demand leads to portable LNG operation under all solutions, though relatively less in scenarios with incremental DSM (lower relative emissions). Higher emissions from fuel-oil customers would be experienced in solutions requiring a moratorium.
Late in Analysis Period (>2030)	Upstream disruption necessitates portable LNG operation where still in place. If major disruption prevents gas delivery, system shut-offs may be necessary without portable LNG operation.	Increased heating demand leads to portable LNG operation where still in place, but no increased emissions for solutions with DSM that avoids portable LNG operation.

Note again that, if portable LNG operation is necessary, total bottom-up system-wide emissions may increase because portable LNG has a higher total effective emissions rate than pipeline gas and/or because cold weather leads to increased energy consumption. But for the solution comparison performed in the GHG analysis presented in Mr. Olney's testimony, this would have a similar impact on each solution meaning the relative results would not be significantly impacted.

PUC 1-9

Request:

On page 8 of the Porcaro testimony, the following statement is made: "A load reduction in any amount would not result in less equipment." Why?

Response:

The Project is scoped to address two issues: capacity vulnerability and capacity constraint. The first issue, capacity vulnerability, is based on the limitation of the single pipeline on the G-2 lateral that cannot be forecasted or anticipated. The equipment scoped for the Project aims to maximize vaporization rate and storage quantity to enable the Company to mitigate the effects of capacity vulnerability events. The second issue, capacity constraint, is a calculated difference between the contracted capacity on the Algonquin G system available to Aquidneck Island and the forecasted demand under extreme cold weather conditions. The capacity constraint issue could be resolved by a load reduction, and a modification or reduction of equipment may be possible; however, a load reduction would not impact the scope of the Project, which is designed to mitigate the effects of a capacity vulnerability event.

Prepared by or under the supervision of: Julie Porcaro

PUC 1-10

Request:

On page 9 of the Porcaro testimony, the following statement is made: "The alternatives the Company considered include the proposed Project, Seasonal Portable LNG Operation at a New Navy Site, Permanent LNG at a New Navy Site, LNG Barge, Reinforcement of the Algonquin Transmission Line, and Non-Infrastructure Solutions. All of the alternatives were more expensive than the Project, did not provide the operational advantages of being located next to the take station, or would take several years to implement during which time the proposed Project would be needed." Please provide the estimated costs for each compared to the preferred solution together with a quantification of "several years" for each.

Response:

The chart below summarizes the estimated costs and time to implementation. This information is taken from Section 4 of the Project Siting Report, which provides additional detail regarding the estimated cost and time to implement each of the analyzed alternatives.

Alternative Considered	**Estimated Cost**	**Estimated Time to Implement**	**Reference Section in Siting Report**
Proposed Project	$15M	1-2 years*	4.2
Seasonal Portable LNG Operation at new Navy site	$54.4M	4-5 years	4.3
Permanent LNG at new Navy site	$149M	4-5 years	4.4
LNG Barge	$76M	3-4 years	4.5
Reinforcement of Algonquin	$183-$265M	4-5 years	4.6
Non-Infrastructure	$286M	N/A**	4.7 and 4.8

* It is estimated that the project would require approximately nine months of construction; however, the work must be phased around the required vaporizing season, which would most likely split the work into two seasons.

** The non-infrastructure alternatives would not address the capacity vulnerability.

Prepared by or under the supervision of: Jeffrey A. Montigny

PUC 1-11

Request:

On page 11 of the Porcaro testimony, the following statement is made: "As explained in the Siting Report, all non-infrastructure options require continued reliance on portable LNG at Old Mill Lane at least for the next several years." For each non-infrastructure option studied, please provide a brief description, the potential cost, and a quantification of "the next several years."

Response:

Please refer to Sections 4.7 and 4.8 in the Siting Report[1] for brief descriptions of the non-infrastructure solutions evaluated.

Potentials costs are presented in Table 4-1 at page 38 of the Siting Report, which is copied below.

Table 4-1. Summary of Evaluated Non-Infrastructure Solutions

Option	Capacity Constraint	Capacity Vulnerability	EE[2] (Dth/day)	DR (Dth/day)	EH (Dth/day)	Utility Cost
LTCR[3] Non-Infrastructure	Solved	Solved	1,394	1,851	10,554	$286M
2021 Non-Infrastructure	Solved	Unsolved	1,278	1,801	2,560	$143M
2021 Non-Infrastructure with Moratorium	Solved	Unsolved	792	1,821	1,087	$100M

[1]Energy Facility Siting Board Project Siting Report entitled "Aquidneck Island Gas Reliability Project Old Mill Lane Portsmouth, RI" prepared for The Narragansett Electric Company by VHB dated April 2022 (the "Siting Report"), which the Company filed with the Energy Facility Siting Board on April 1, 2022, in Docket No. SB-2021-04.
[2] Energy efficiency ("EE"); demand response ("DR"); and electric heat ("EH").
[3]Aquidneck Island Long Term Gas Capacity Study (published in 2020) ("LTCR") *available at* https://www.nationalgridus.com/media/pdfs/other/aquidneckislandlong-termgascapacitystudy.pdf.

Prepared by or under the supervision of: Julie Porcaro

PUC 1-11, Page 2

The timeframes for implementation non-infrastructure solutions are uncertain because they depend upon customers' voluntary adoption of alternative energy sources and energy efficiency measures. The Company estimates that there is no scenario under which the solutions could be implemented in less than ten years. More detail concerning the factors considered in estimating a non-infrastructure solution implementation time can be found in Sections 4.7 and 4.8 of the Siting Report and in the Technical Appendix for Non-Infrastructure Resources beginning on page 108 of the LTCR.

PUC 1-12

Request:

Please provide a schedule itemizing the project costs totaling $15 million and the annual O&M costs totaling $1.5 million.

Response:

For itemized Project costs totaling $15 million, please see Attachment PUC 1-12-1.

For itemized costs for the annual O&M costs totaling $1.5 million, please refer to Attachment PUC 1-12-2.

With respect to Attachment PUC 1-12-2, please note that the annual O&M cost estimate for the Project had been reported to be approximately $1.5 million; however, this amount is no longer accurate. The original annual operating cost for the project was primarily based on contractor labor and equipment rental costs, seasonal site work (temporary matting and fencing), and Company staffing costs. Contracted labor and equipment rental has increased significantly since the original estimate, while cost savings have been achieved with the installation of permeable ecoraster surfacing to eliminate the need for mat rentals and the installation of permanent fencing. The Company, therefore, has investigated the cost to purchase equipment and to staff the operation with Rhode Island Energy employees, in an effort to stop the annual cost increases associated with contract labor and equipment rental.

Attachment PUC 1-12-2 reflects the current O&M estimates for operating the site without contracted LNG services. This estimate is currently $825,000 for the annual O&M budget. The decision to execute on the purchase of equipment and the hiring of employees to staff the site is subject to the approval of this Project.

Prepared by or under the supervision of: Brian K. Kirkwood and Jeffrey A. Montigny

Old Mill Lane Estimate Assumptions

Item	Assumption	Cost
Civil Improvements, Field Labor, Labor Management, Internal Labor Support	Field Construction Contractor, Field Supervision, Pressure Regulation, LNG Ops, Field Ops, Project Management, Engineering support, In-house Environmental, Contracted Environmental, Legal, Vegetation removal, grading, gas main relocation, manifold relocation, environmental features, site infrastructure, fencing, paving.	$5,713,500
Process Systems	Vaporizers, storage tanks, trucking, liquid processing equipment, staffing	$823,215
Commissioning	Set up, Testing and Commissioning	$150,000
Security	On-site 24 hour	$150,000
Plant Improvements	Electrical, above ground hard pipe to reduce use of hoses.	$225,000
SUBTOTAL		**$7,061,715**
Capital Burdens	24% Capital burden	$1,694,812
AFUDC	Funds used during Construction	$284,587
SUBTOTAL		**$9,041,114**
Contingency - 30%		$2,712,334
TOTAL PROJECT COST		**$11,753,448**
Escalation 3.5%		$411,371
SUBTOTAL		**$12,164,818**
P50 Unidentified risk		$2,432,963.67
Final Estimate		**$14,597,782**

OML Annual OPEX

ORIGINAL ANNUAL ESTIMATE	
Item	**Cost**
Site set-up with matting, fencing install, storage & vaporizing equipment rental, contractor staffing, in house LNG staffing, trucking, liquid processing equipment, connections, purging, testing.	$1,500,000

REVISED ANNUAL ESTIMATE POST PROJECT APPROVAL	
Item	**Cost**
Crane services for office trailer installation & sound wall installation	$20,000
Sand bag berm installation / Removal	$20,000
Restroom Facilities	$10,000
Emergency Generator Maintenance / Transportation costs	$5,000
Electrical Setup / Breakdown	$50,000
Manifold Maintenance	$10,000
Vaporization / Queen O&M	$50,000
Snow Removal Services	$20,000
Miscellaneous Supplies / Maintenance	$20,000
Security	$120,000
RIE Labor to operate the site	$500,000
TOTAL:	**$825,000**

Costs no longer required with current configuration (ecoraster and permanent fencing)	
Mats	$200,000
Jersey Barrier	$50,000
Temporary Fencing	$30,000
Sandbag rental	$20,000
Equipment rental, commissioning, decommissioning, and mobilization cost	$720,000
TOTAL:	**$1,020,000**

LNG Storage Tank and Vaporizer Quotations For Proposed Purchase			
Item	**Cost per unit**	**Units**	**Total**
750 MSCFH water glycol vaporizers	$1,198,789	2	$2,397,578
Smart Queen with internal pump	$829,730	6	$4,978,380
Overhead 25%			$1,843,990
Total:			**$9,219,948**

PUC 1-13

Request:

Referencing the purchase of the equipment,

a. Is the purchase of the equipment at $9.2 million for the winter 2023-2024 or the winter 2024-2025? (Montigny Testimony at page 5).

b. Is the purchase of the equipment in the FY 2023 Gas ISR Filing that was made by the Company on December 23, 2022?

c. Is the purchase of the equipment contingent upon EFSB approval of the Company's project proposal? Please explain.

Response:

a. The Company has not yet purchased or placed a deposit on the portable LNG equipment for the Old Mill Lane facility. The Company did, however, purchase portable LNG equipment for its Cumberland LNG facility that will go into service during calendar year ("CY") 2023 for the 2023/2024 winter heating season. The cost estimate referenced on Page 5 of Company Witness Jeffrey A. Montigny was for the purchase of equipment for the Cumberland LNG facility. The total estimated cost for the purchase of portable LNG equipment for use at Old Mill Lane is $2.51 million during CY 2023 and $9.2 million during CY 2024, for a total of $11.51 million. The difference between the 2022 $9.2 million estimate given earlier and the filed $11.51 million estimate is a contingency for an anticipated price increase because of inflation and the cost of materials. This equipment would be placed into service in CY 2025 for the 2025/2026 winter heating season.

b. The Company included the proposed purchase of portable LNG equipment for the Old Mill Lane facility in its Fiscal Year ("FY") 2024 Gas Infrastructure, Safety, and Reliability ("ISR") Plan, which was filed with the Public Utilities Commission on December 23, 2022, in Docket No. 22-54-NG. Please note- that, although the portable LNG equipment for Old Mill Lane is included in the CY 2023 and CY 2024 budgets, it would not have a customer rate impact until CY 2025 when the Company forecasts that it will be placed in service.

Prepared by or under the supervision of: Brian K. Kirkwood, Nathan Kocon, and Jeffrey A. Montigny

PUC 1-13, Page 2

c. Ordering portable LNG equipment for Old Mill Lane is contingent upon the Energy Facility Siting Board approval of continued portable LNG operations at Old Mill Lane and Public Utilities Commission approval of the Company's FY 2024 ISR Plan. If both approvals are granted, the Company plans to place an order in CY 2023 for portable LNG equipment that will be used at Old Mill Lane. The equipment could be used at the future desired footprint, which is set back further from the street, or it can be used on the existing footprint of Old Mill Lane. Because of the long lead times for this type of equipment, it is critical that an order be placed in CY 2023. Current lead times range from six to twelve months and vary with the availability of manufacturing capacity, which is also impacted by other customer orders. The equipment purchase will require a 25% deposit in CY 2023 with targeted equipment completion in CY 2024. The planned in-service date of the portable equipment is CY 2025. Although the new owned equipment may be in the Company's possession in CY 2024, the existing leased equipment would be used for the duration of the 2024/2025 winter heating season. Then the new owned equipment would be fully set up for the 2025/2026 winter heating season. Having the new owned equipment in service is also dependent upon hiring and training Company employees to operate the site with the same services currently provided by contracted services. The portable LNG operations are critical to the reliability of gas operations on Aquidneck Island. Thus, the portable LNG equipment will be necessary to support gas operations on Aquidneck Island.

Prepared by or under the supervision of: Brian K. Kirkwood,
Nathan Kocon, and Jeffrey A. Montigny