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August 15, 2016

BY HAND DELIVERY

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

Re: Docket 4627 – In Re: Request for Approval of Firm Transportation Contracts with Algonquin Gas Transmission, LLC for the Access Northeast Project
Responses to Data Requests

Dear Ms. Massaro:

On behalf of National Grid,[1] enclosed are National Grid's responses to the Second Set of Data Requests issued by the Rhode Island Office of Energy Resources in the above-referenced matter.

Thank you for your attention to matter. If you have any questions, please contact me at (617) 951-1400, or Jennifer Brooks Hutchinson at 401-784-7685.

Very truly yours,

John K. Habib

Enclosures

[1] The Narragansett Electric Company d/b/a National Grid.

OER 2-1

Request:

Please clarify if the EDCs will be releasing LNG capacity or just providing bundled service with the LNG, or both? If releasing LNG capacity, how will this work operationally and for inventory accounting? Will shippers be held to rule curves requiring certain refill schedules and maximum withdrawals? Will the capacity manager need to maintain separate inventory records for each shipper?

Response:

Figure 1 of the Electric Reliability Service Program (ERSP) describes the initial plan of the timing and percentage of the pipeline and storage capacity. The EDC-Working Committee will continuously monitor and make adjustments to the plan as market conditions warrant a more optimal release of the assets. As described in the plan it is expected that some portion of the LNG capacity and the associated pipeline capacity will be released to the generators with some possibly remaining under the control of the EDCs through its capacity manager. FERC capacity release rules require that the capacity shipper hold title to the natural gas whether it is in storage or transported on pipeline capacity. It will be the responsibility of any generator as the new shipper of LNG storage capacity to maintain all operational and accounting requirements. FERC capacity release rules also do not allow any tying arrangement associated with a release of storage or transportation capacity and therefore having certain requirements such as storage rule curves may not be allowed. The capacity manager will only have to manage the capacity retained by the EDCs.

OER 2-2

Request:

How much of the ANE pipeline capacity will need to be retained for LNG refill? Please specify if it varies by season? Will the cost of pipeline capacity used for liquefaction and refill be included in the inventory cost?

Response:

The LNG storage facility has a working capacity of 6.4 Bcf with an associated injection right of 54,000 dt/day. The LNG storage facility has the capability of two full injection and withdrawal cycles per year. The two withdrawal periods per year are July 20th to August 31th and December 1st to March 31st. During the off-peak periods 54,000 dt/day of transportation capacity from Mahwah, Ramapo and Brookfield to the LNG facility at Acushnet will be allocated in a ratio of the storage capacity to injection rights to each LNG storage capacity shipper.

Only the variable costs to transport, inject and store LNG supplies will be included in the inventory costs. Inventory costs are described in more detailed in the Company's response to Data Request OER 1-3. Fixed demand charges will not be included in the inventory costs.

OER 2-3

Request:

What is the maximum daily volume of capacity that will be released to any one shipper?

Response:

The EDCs have not defined a maximum daily volume limit to any one shipper.

OER 2-4

Request:

When the capacity manager releases capacity not required by generators, will that be under existing capacity rules? Or does it depend upon who the customer is? i.e. another generator inside or outside of New England, or a non-generator shipper?

(a) What recall provisions will be included? If so, what type of recall?
(b) How will such recall provisions, if any, affect the market value of the released capacity?

Response:

Capacity not required by generators will be made available to be released to all market participants under existing FERC release capacity rules.

(a) If necessary, released capacity will have provisions in the release to recall the capacity if needed for electric reliability. The decision to include recall rights will be dependent on the duration of the capacity release, the time of year and the total quantity of non-exempted capacity already released to the market.
(b) Any released capacity encumbered with recall rights will have some reduced value. The amount of the discount will vary depending on the term of the release, time of the year and the new shipper's expectation that capacity will be recalled.

OER 2-5

Request:

Will Acushnet LNG be sold into the market? Or will it be reserved exclusively for generators only in the peak or for no-notice service?

Response:

Figure 1 of the Electric Reliability Service Program (ERSP) describes the initial plan of the timing and percentage of the pipeline and storage capacity releases. The EDC- Working Committee will continuously monitor and make adjustments to the plan as market conditions warrant a more optimal release of the assets. As described in the plan it is expected that some portion of the LNG capacity and the associated pipeline capacity will be released to the generators with some possible remaining under the control of the EDCs through its capacity manager.

OER 2-6

Request:

Will the capacity manager offer bundled sales to the market? If so,

(a) Will the asset manager pay for the capacity and procure supplies for bundled sales, or simply be the agent for the EDC's?
(b) Will bundled sales be limited to LNG supplies?
(c) Will the capacity manager be acquiring supplies upstream from producers?
(d) Will such supplies be on a contract, or spot basis?
(e) If it's the EDCs who procure the supply, does this get the EDCs into the gas marketing business?
(f) If the EDCs have limitations on the types of gas contracts they can procure, does this diminish the value of bundled supply contracts and reduce the benefits to EDCs' customers?
(g) What types of additional risks to customers, if any, does it present if the asset manager has financial control of the capacity and is tasked with the purchase of gas for LNG refill and bundled sales? Conversely, if the arrangement is an administrative one, what additional risks is it to the EDCs' customers if the EDCs' get into the gas acquisition and marketing business?

Response:

The Company plans to release as much capacity to the generators and other market participants as possible but the Company anticipates that some capacity may remain with the capacity manager. If some transport or storage capacity remains with the capacity manager it is expected that the capacity manager will execute bundled sales.

(a) The capacity manager agreement can be set up as either an asset management or as agent for the various EDCs. The optimal arrangement will be determined based on the results of the RFP for capacity management services.
(b) It is expected that bundled sales will be executed for any of the assets retained by the capacity manager.
(c) The capacity manager should have the ability to procure supply at any of the receipt points on the Algonquin pipeline downstream of Mahwah from any market

participant contingent upon having master agreements (NAESB) to procure supply with the counter parties.

(d) It is anticipated that most purchases will be on a daily basis but would not preclude the capacity manager from doing greater than daily deals if warranted.

(e) The Company does not believe that managing capacity from the ANE Project on behalf of electricity customers is any different than its role historically managing capacity associated with interstate pipeline contracts for its gas customers, and would not put Narragansett Electric Company in the gas marketing business.

(f) The only limitation anticipated is the number of master agreements (NAESB) between the EDCs, if the capacity manager arrangement is an agency, or the capacity manager, if done as an asset management agreement, and other market participants in the region. The value would only be diminished if there were not an adequate number of counter parties.

(g) If the capacity manager contract is done as an asset management agreement then the risks are no different than any asset management agreement.

OER 2-7

Request:

Would no-notice service be available to other market participants acquiring released ANE capacity? If not, why not? Would generators pay a premium for ANE capacity due to the no-notice service provisions vs. market capacity?

Response:

No notice service will be available to any company acquiring both the storage capacity and the transportation capacity from Acushnet to the various Power Plant Aggregation Areas (PPAA). Assuming the OER defines market capacity as the value of capacity from the receipt points of Mahwah and Ramapo to the Algonquin City-gate delivery points (PPAAs) then it would not be a comparison of like assets since the receipt points are different and there is the additional storage asset. The no-notice aspect has a higher value than just straight transportation capacity but the Acushnet receipt point has a lower value than the Mahwah and Ramapo receipt points.

OER 2-8

Request:

If RI wanted to allow Generators who have acquired capacity on a monthly, seasonal or annual basis to re-release capacity they are not using and that would not create a reliability concern under normal release/re-release rules, would the EDCs oppose this provision? For example, could a generator re-release its ANE capacity during plant maintenance periods, or any periods when the generator may not expect to run?

Response:

The EDCs have anticipated that some capacity releases may be made available under normal capacity release rules. Depending on the term and time of year it may be necessary to have recall rights associated with the release and re-release.

OER 2-9

Request:

Is the B&V cost/benefit analysis contingent upon underutilized generator capacity making it into the marketplace through capacity release, thereby putting downward pressure on basis? Or is this not a factor in the B&V analysis? If not, how would availability of LNG capacity that is underutilized by the generator further impact basis?

Response:

Black & Veatch's cost/benefit analysis is not contingent upon underutilized generator pipeline or Acushnet LNG vaporization capacity making it into the marketplace through capacity release. Black & Veatch's cost/benefit analysis is contingent upon the completion of the ANE project as proposed, and that the ANE capacity is available to be utilized by generators in the marketplace, which would reduce the level of constraints on existing pipelines, and place downward pressure on regional price/basis.

OER 2-10

Request:

How much of the 400,000 Dth/day of Acushnet LNG capacity/bundled sales/day will the EDCs or capacity manager have to withhold from generators or from the market in order to provide the ANE no-notice service?

Response:

The first priority will be to get the capacity to the generators to increase reliability and help lower the cost of New England supplies and mitigate volatility. The EDC-Working Committee has yet to determine how much, if any, of the Acushnet LNG storage capacity will be retained by the EDCs to provide no-notice service.

Prepared by or under the supervision of: Stephen A. McCauley

OER 2-11

Request:

Is the ANE capacity comparable to electric transmission capacity for the purposes of allowing generators access to electric markets? If not, please describe the differences?

Response:

The ANE capacity is not directly comparable to electric transmission capacity that is built for the purposes of allowing electricity generators access to electric markets. However, both electric transmission capacity and natural gas transportation capacity are comparable in that inadequate levels of either type of delivery infrastructure can cause significant reliability and cost concerns for the electricity markets and the customers served by those markets.

The ANE Project will alleviate the winter-time shortage of firm natural gas transportation capacity for electricity generation that has saddled the Company's customers with excessive energy commodity costs due to high and volatile wholesale natural gas and thus electricity prices. In short, rather than allowing generators access to "downstream" electricity markets to sell their electricity output, the ANE Project will give electricity generators access to "upstream" liquid natural gas fuel markets to procure their fuel input.

The electricity generators who will have access to natural gas fuel for power generation as a result of the ANE Project already have access to electric markets. What they lack, owing to their unwillingness or inability to sign long-term contracts for firm transportation capacity, is access to natural gas to fuel their generation at reasonable costs during peak winter periods, which either leads them to rely on costly and scarce spot market natural gas or more expensive and more environmentally damaging fuel oil (if they have dual-fuel capability) or to be unable to generate at all during peak periods owing to lack of fuel.

OER 2-12

Request:

Will the winter reliability program be necessary if ANE comes online? At what phase would the EDCs and ISO expect the winter reliability program would no longer be necessary?

(a) What has been the annual cost of the winter reliability program to New England and Rhode Island customers since its inception?
(b) Has elimination of the cost of the winter reliability program been factored into the cost/benefit analysis?

Response:

National Grid understands that the winter reliability program will end after the winter of 2017-2018.

(a) National Grid has not calculated the annual cost of the winter reliability program to New England and Rhode Island customers since its inception. However, ISO-NE has reported a winter 2013/14 reliability program cost for the region of approximately $65 million, a winter 2014/15 reliability program cost of approximately $45 million (please refer to slides 5 and 6 of the ISO-NE presentation available at http://www.iso-ne.com/static-assets/documents/2015/09/final_gillespie_raab_sept2015.pdf), and a winter 2015/16 reliability program cost of approximately $41.2 million (please refer to slides 9 and 10 of the ISO-NE presentation available at http://www.iso-ne.com/static-assets/documents/2016/05/may-2016-coo-report.pdf).

(b) The elimination of costs associated with the winter reliability program has not been factored into the cost/benefit analysis of the ANE Project.

OER 2-13

Request:

What is the risk to EDC customers if ANE capacity is released to the marketplace without the targeted waiver?

(a) Would the region still be short on natural gas infrastructure if ANE goes online when including generator, gas LDC, and gas marketer requirements?
(b) What risk exists that ANE capacity would have more value to non-New England markets than to New England markets? What such scenarios exist that could support keeping ANE capacity out of the normal capacity market?
(c) What risks will generators have if they do not acquire sufficient capacity to cover their generating commitments? How will "Pay For Performance Penalties" encourage generators to make sure they can perform when called upon?

Response:

The targeted release gives the EDCs the ability to best ensure that the capacity is used by generators to generate electricity for its customers. Two risks if the capacity is not released on a targeted basis are: (a) if the forecasted natural gas load from other demand sources is much higher; or (b) LDCs do not contract for the forecasted demand growth as assumed in the B&V model. In both cases the incremental demand will compete for the ANE capacity with the generators.

a) While additional infrastructure might still provide additional reliability and economic benefits, Black & Veatch does not believe that the New England region would be short on natural gas infrastructure when the ANE Project is completed and placed into service in 2021. Black & Veatch assumes gas LDCs will continue to contract for the infrastructure necessary to satisfy their requirements.

b) The potential risk for the ANE capacity to have more value in a non-New England market would come from either eastern Canada or LNG exports. The risk of demand from eastern Canada that would be significant enough to impact the value of ANE capacity is low. The population would have to increase significantly or there would need

to be a significant growth in industrial demand. The LNG export risk is also low since no New England or eastern Canada LNG facility has liquefaction facilities capable of exporting LNG. In addition, the equivalent price to export from either Cove Point or the Gulf of Mexico is much lower than the forecasted New England price.

c) ISO-NE provided the following information on expected results of the "Pay-for-Performance" in a July 6, 2015 letter to the Massachusetts Department of Energy Resources (available at http://www.iso-ne.com/static-assets/documents/2015/07/iso_response_doer_info_request_july2015.pdf):

> Pay-for-performance
>
> Over a period of several years, the ISO observed deterioration in performance across much of the region's generating fleet during times when the power system was operating under stressed conditions. The ISO determined that the resource performance requirements in the Forward Capacity Market (FCM) were not sufficient to ensure a reliable system and we concluded that this posed a serious risk to power system reliability. The ISO worked through a regional stakeholder process and the Federal Energy Regulatory Commission (FERC) subsequently approved our proposal to strengthen the FCM performance obligations and incentives with what is referred to as "pay-for-performance" or "PFP."
>
> PFP created a two-settlement system to compensate resources in the capacity market. Resources that clear in a capacity auction are eligible to receive a base capacity payment. Then, if scarcity conditions exist (i.e., the power system in experiencing a shortage of operating reserves), PFP will pay resources based on their performance during those conditions; resources that over-perform will receive a payment, while those that underperform will receive a charge. PFP creates strong financial incentives for capacity suppliers to perform when called on during periods of system stress.

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

PFP is intended to create incentives for generators to make cost-effective investments to ensure they are able to perform when called on by the ISO. Most instances of non-performance by gas-fired generators during the winter season are due to the lack of access by those generators to firm gas transportation when the gas pipelines become constrained, since typically these generators do not hold firm gas transportation rights. PFP will create strong incentives for gas-fired generators to firm up their fuel supply, however it does not prescribe which solution a resource should pursue. Our analysis has concluded that installing dual fuel capability is the most cost-effective option for a typical gas generator. Thus, PFP will improve resource performance, but it will not necessarily result in added natural gas pipeline capacity, as individual generators are not likely to enter into the long-term contracts needed to fund additional gas infrastructure as long as cheaper alternatives such as dual-fueling exist.

While these actions should maintain a reliable supply of electricity under most conditions, relying on dual fuel capability is only a viable option if the states approve permits to burn oil. During the winter months when the pipelines are constrained, the region is typically dependent on the utilization of non-gas electrical supply to maintain reliability. This highlights a longer term reliability risk. More than 3,000 MW of non-gas generation have retired, or announced plans to retire, and there is the potential for further significant retirements of coal, oil and nuclear units in the years to come. Many of these resources are forty years of age or older and are experiencing significant financial and environmental pressures. As these resources cease operation, they will be replaced in large part by gas-fired resources (with the need for dual fuel capability). This will increase the demand for natural gas infrastructure to supply fuel for new resources.

Prepared by or under the supervision of: Denny K. Yeung and Gary J. Wilmes

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OER 2-14

Request:

How will EDCs and the capacity manager prioritize the use of the ANE capacity between the following? If other markets or services have been omitted, please include. Please explain how this priority changes for a peak and non-peak day or period?

(a) No notice service
(b) LNG storage refill
(c) Generator initial capacity release
(d) Generator capacity recall and re-release
(e) General market capacity release
(f) Bundled sales to generators in the New England market
(g) Bundled Sales to non-generators in the New England market
(h) Bundled sales outside of the New England market

Response:

The following priority list has not been vetted with the EDC-Working Committee but is the Company's opinion of how capacity can be prioritized. The first priority will be to get the capacity to the generators to increase reliability and help lower the cost of New England supplies and mitigate volatility. On a priority basis the storage and transportation capacity will be released as proposed in Figure 1 of the ERSP. Transportation capacity needed to refill the LNG facility will then be allocated to the LNG storage shipper as part of the release of the storage capacity. Any capacity remaining will first be allocated to bundled sales as needed. Any excess capacity not forecasted to be needed for generation will be made available for generator re-releases or for general market capacity releases.

Prepared by or under the supervision of: Stephen A. McCauley

OER 2-15

Request:

Is it likely that generators will be able to bid less than open market value for ANE released capacity under the waiver and still get capacity?

Response:

Capacity released to the generators under the waiver may either be non-re-releasable and/or recallable. Capacity with either one or both of these conditions will have less value than capacity without any conditions. The waiver allows the EDCs to release capacity to only the generators and therefore will most likely result in capacity being released at a discount to capacity without such conditions. It should also be noted that without the waiver, the capacity that is released to all market participants with the same conditions will also be valued at a discount to capacity without conditions.

Prepared by or under the supervision of: Stephen A. McCauley

OER 2-16

Request:

Could the capacity be placed for bid to the market to establish a market price and allow generators to match the highest bid to receive capacity? Would this provide a better value to EDC customers? If not, why not?

(a) If a Generator declines to match the highest bid, would that indicate a more economic source of supply exists?

Response:

The scenario described above already exists under current capacity release rules and is referred to as the prearranged shipper. Capacity releases can be posted to the bulletin board as biddable with a prearranged shipper. If during the posting period the capacity is bid higher by another company the prearranged shipper has the right to match the highest bidder. Although this may result in higher value for the capacity it does not ensure the capacity will be available to generate electricity and may result in higher electric prices.

(a) A more economic source of supply may be one reason a generator does not match the highest bid.

Prepared by or under the supervision of: Stephen A. McCauley

OER 2-17

Request:

What is the maximum size block of capacity the capacity manager will be putting out to generators for release or re-release to the market?

Response:

The maximum capacity block size has not been established at this time.

Prepared by or under the supervision of: Stephen A. McCauley

OER 2-18

Request:

Have the EDCs met with generators and discussed the types of services the ANE project could provide? Have the generators expressed interest in:

(a) Capacity release

(i) 1 year term
(ii) Seasonal
(iii) 1 month
(iv) Daily
(v) Intraday
(vi) Other term?

(a) Bundled sales
(b) Managing LNG injections and withdrawals themselves?
(c) Are these services that would not be available to generators absent EDC acquisition of the ANE contract?

Response:

For purposes of this response, the term "EDC" refers to The Narragansett Electric Company d/b/a National Grid (referred to herein as the Company). The Company has not met with any generators to discuss the ANE project or types of services it could provide.

OER 2-19

Request:

Have the EDC's met with opposition for the EDC ANE contract from generators? If so, please outline the issues generators have with the EDCs contracting for ANE capacity?

Response:

Please see the Company's response to Data Request OER 2-18. The Company is unsure of what is meant by "opposition" for purposes of this request. The Company has not met with any individual stakeholders regarding the ANE contract; however, several parties have intervened in the Massachusetts Docket D.P.U. 16-05 and their respective positions are on file and publicly available in the docket, which can be accessed at:

http://web1.env.state.ma.us/DPU/FileRoom/dockets/bynumber/16-05

OER 2-20

Request:

Will Generators or their agents be able to make bundled sales to other generators or non-generator parties when capacity is not being used by the generator?

Response:

Yes, generators or their agents will be able to make bundled sales when not needed for generation.

Prepared by or under the supervision of: Stephen A. McCauley

OER 2-21

Request:

Please calculate what the Company believes to be the price premium New England retail customers paid in aggregate as a result of natural gas pipeline constraints for each of the winters of 2013/14, 2014/15, 2015/16; and for a typical residential customer by year? Please state all price assumptions.

Response:

In the Company's response to Data Request PUC 1-10, the Company provided the following table:

	Winter (Dec -Feb)				
	2011/12	2012/13	2013/14	2014/15	2015/16
Avg. Gas Price @ Algonquin City Gate ($/mmBtu)	$ 4.40	$ 11.26	$ 19.56	$ 10.73	$3.40
Total Cost of ISO-NE Electric Energy Market ($Billions)	$ 1.2	$ 2.9	$ 5.0	$ 2.8	$ 1.0

This table indicates that the significant price increases for the natural gas used to fuel much of the region's power generation fleet were the primary drivers of New England wholesale electric energy market costs increases of $1.7 billion in the winter of 2012/2013, $3.8 billion in the winter of 2013/2014, and $1.6 billion in the winter of 2014/2015, all compared to the winter of 2011/2012. This indicates a total electric energy market cost premium, primarily driven by the natural gas pipeline capacity constraints affecting the region, of approximately $7 billion over these three winters.

Such wholesale energy market cost increases or premiums are not seen immediately by all retail customers since most are not under retail rates set to immediately recover wholesale spot market prices. Most electric distribution companies (EDCs) in New England procure power supply on behalf of their customers through Full Requirement Service (FRS) contracts prior to the rate period. Similar to Standard Offer Service procurement, many EDCs procure power supply in a laddered and layered manner at various times prior to the beginning of a rate period, while others procure 100% of the power supply at a single point in time prior to a rate period. Likewise, many customers obtaining supply from competitive suppliers enter into forward, fixed price

contracts for set periods of time. The retail rate payments are based on such contracts and, therefore, are not the always immediately reflective of the wholesale energy market settlement costs. Thus, the price premium New England retail customers paid in aggregate as a result of gas pipeline constraints may be higher or lower for each winter than the applicable wholesale energy market's premium. However, over the long run, wholesale market cost premiums resulting from natural gas pipeline constraints, if unresolved, will be fully reflected in the costs of supply, and thus fully paid in aggregate by New England retail customers.

Please also refer the Direct Testimony of Ann E. Leary, pages 7 and 8, providing information on illustrative bill impacts which reflect the levelized net benefits projected by Black & Veatch for the ANE Project.