Raquel J. Webster
Senior Counsel

March 1, 2018

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4783 - Proposed FY 2019 Electric Infrastructure, Safety, Reliability Plan
<u>Responses to PUC Data Requests – Set 4</u>

Dear Ms. Massaro:

On behalf of National Grid,[1] I have enclosed ten (10) copies of the Company's responses to the fourth set of data requests issued by the Rhode Island Public Utilities Commission in the above-referenced docket.

Thank you for your attention to this transmittal. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4783 Service List
Greg Booth, Division
Leo Wold, Esq.
Al Contente, Division

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

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PUC 4-1

Request:

In Docket No. 4780, page 137-145, the Company lays out a storage proposal wherein it proposes partnering with several potential entities, all located in Providence, Rhode Island, to host physical energy storage systems and integrate those projects with educational offerings by the entities. The Company states the project will provide "direct benefits to partner organizations in the form of energy and cost savings." (p.137).

(a) Has the Company reviewed this proposal in conjunction with the Providence Area Studies to determine whether the storage proposal would provide any benefit to the local distribution system? If not, why not?
(b) Has the Company incorporated the storage proposal into its distribution system planning analysis? If not, why not?

Response:

(a) The Providence Study did analyze the use of energy storage in north and west Providence to address feeder contingency issues. This analysis is attached as Attachment PUC-4-1. At $450k and $600k per MWh, the Company determined that the proposal was economically inferior to the wires solution. As referenced in the Providence Area Study, there are opportunities for system benefits, but those benefits need to be weighed against the potential use cases available from partnering organizations in those areas as the locations and partners are identified.

(b) Energy storage is a technology considered with the NWA analysis conducted as part of distribution system planning, as evidenced by the energy storage proposal in Tiverton, Rhode Island in the 2018 System Reliability Procurement filing. However, the Energy Storage proposal included in the Power Sector Transformation has not yet identified a location or partner facility.

Prepared by or under the supervision of: Ryan Constable

Appendix: Evaluation of Energy Storage Solution

Energy storage was evaluated as a potential solution for the loss of the 13F4 or 13F5 feeders, specifically for the loss of the getaway cable for an assumed duration of 12 hours.

Assumptions

To evaluate an energy storage solution, 2015 peak-day load curves on the two feeders were extended to an estimated 2030 load, peaking at 11.8 and 9.6MVA for the 13F4 and 13F5, respectively. It was assumed that load could be picked up from other feeders in the case of an outage, specifically 9.5MVA of load on 13F4 and 5.6MVA of load on 13F5. This would leave a peak unmet load of 2.3 and 3.9MVA respectively. These load curves and switching assumptions were used to derive battery specifications that would avoid unserved load for approximately 12 hours in the case of the loss of getaway cables for 13F4 or 13F5.

Resulting storage systems

The analysis identified a solution in the form of two separate battery storage systems, one at Geneva to serve 13F4 and one at Marieville to serve 13F5. The performance of these systems is shown in Figures 1 and 2, assuming a 3MW/15MWh system at Geneva, and a 6MW/36MWh system at Marieville.

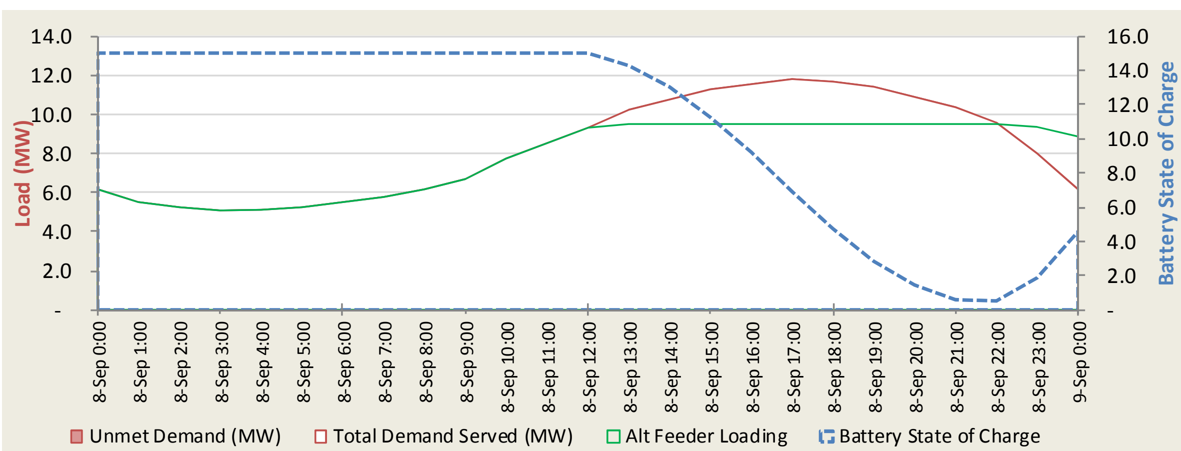

Figure 1: Feeder 13F4, Unmet Demand and State of Charge with 3MW/15MWh battery, 2030 peak day load

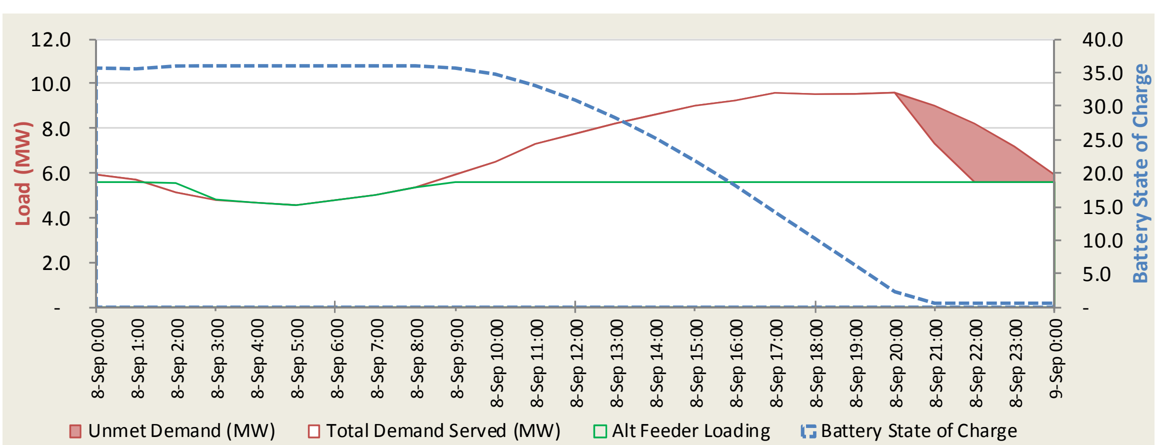

Figure 2: Feeder 13F5, Unmet Demand and State of Charge with 6MW/36MWh battery, 2030 peak day load

As the figures show, the proposed 6MW/36MWh system for 13F5 does not avoid lost load altogether. Rather, both suggested systems achieve approximately 12 hours of relief during peak hours to allow time for getaway cable repair. The main difference between the graphs arises from the severity of the conditions on feeder 13F5, where load requirements even under proposed switching actions would be significantly higher than load requirements on feeder 13F4. In both cases, achieving this level of relief would require that the batteries be held in full state of charge (SOC) during peak months, and at a relatively high SOC during shoulder periods.

Estimated costs and revenues

The cost of the two battery systems were then estimated using a figure of $600,000/MWh for the smaller Geneva system, and $450,000/MWh for the larger Marieville system. In addition, the O&M expenses were estimated at $5,000/MWh/year for the two systems. Both the capital cost and O&M estimates were derived from current industry pricing, as gathered by the Group Technology team at National Grid.

Batteries are unique in that they can also generate revenue from wholesale market activities during hours when not held in full state of charge. While it is unclear whether National Grid operating companies can directly participate in – and monetize -- such activities, revenues can be approximately estimated. ISO-NE frequency regulation revenues were estimated assuming 80% availability around the year, and $20/MWh clearing prices. The resulting revenues were $400,000/yr for the Geneva 13F4 system, and $840,000/yr for the Marieville 13F5 system. Neither system assumed revenues from ISO-NE forward capacity markets, since responding to an ISO-NE capacity call would conflict with holding the batteries in full SOC.

Feeder	Battery Location	Power rating (MW)	Duration (hours)	Energy rating (MWh)	Assumed cost ($/MWh installed)	Est. capital cost	Estimated O&M costs	Estimated Annual Revenues (ISO-NE markets)
13F4	Geneva	3	5	15	$600,000	$9.0M	$75k/yr	$400K/yr
13F5	Marieville	6	6	36	$450,000	$16.2M	$180k/yr	$840K/yr
						$25.2M	**$255/yr**	**$1.3M/yr**

The expected life for these systems would be approximately 12 years, with regular augmentation of battery capacity beginning in year 5, to mitigate the effects of degradation that occurs both through use (cycle fade) and time (calendar fade). These augmentation costs are included in the O&M estimates.

Summary

In sum, the estimated capital cost of the energy storage solution is estimated at $25.2M dollars. O&M costs would be approximately $255K per year, and revenues would be approximately $1.3M per year. Assuming full monetization of wholesale market activities (frequency regulation), net annual cash flow would be positive – approximately $1M per year. If full monetization of these wholesale market activities were not available, net annual cash flow would be negative, in the form of ~$255K per year in O&M costs.

PUC 4-2

Request:

Regarding the VVO/AMI capital costs, does the Company plan to collect the undepreciated costs associated with the existing meters that are removed? At what point will the undepreciated asset balance be expensed? Where is that reflected in the pilot cost?

Response:

Yes, the Company expects to recover the costs of undepreciated meters that are replaced by AMI meters. In the normal course of operations, some Company assets are retired before the end of their depreciable lives while other assets are retired after the end of their depreciable lives. Almost no assets are retired exactly at the end of their depreciable lives. Any net under- or over-recovered plant balances that occur due to this phenomenon are considered in the course of periodic depreciation studies, usually as part of a base rate case, and depreciation rates are adjusted to recover such amounts. Although the potential premature retirement of some meters as a result of providing customers with the benefits of AMI technology may not be in the normal course of operations, the Company would expect to eventually recover the net undepreciated meter costs through an adjustment to future depreciation rates.

There are no undepreciated meter costs reflected in the costs of the AMI pilot.

Prepared by or under the supervision of: Jacquelyn Bean, James Perkinson, and William Richer

PUC 4-3

Request:

Referencing PUC-2-17(b)-(c), please confirm that all of the Capex costs are related to the AMI/VVO pilot. If not, which ones will be incurred anyway in FY 2019, and for which project(s)?

Response:

The Company's estimated CAPEX costs are all related to the AMI/VVO pilot.

PUC 4-4

Request:

Is the Company proposing to include all Capex costs related solely to the pilot (as set forth in PUC-4-3) in rate base?

Response:

The Company filed a distribution base rate case on November 27, 2017 (Docket No. 4770), with new rates to become effective September 1, 2018. Also effective September 1, 2018, the Fiscal Year (FY) 2019 Electric Infrastructure, Safety and Reliability (ISR) Plan rates will be set to zero, and all ISR capital assets will become part of distribution rate base and be recovered from customers through base rates.

Rate base in Docket No. 4770 includes actual electric net plant in-service as of the end of the June 30, 2017 test year, plus an estimate of post-test year electric plant additions through the end of the rate year (the twelve months ended August 31, 2019) at the PUC-approved FY 2018 Electric ISR Plan levels, and an estimate of non-ISR additions through the end of the rate year. The ISR-based estimate of plant additions built into rate base in the rate case will ultimately be reconciled to actual FY 2019 ISR plant in service, including actual AMI pilot costs and the revenue requirement on any over or under recovery will be returned to, or recovered from, customers as part of the normal ISR reconciliation process.