February 19, 2016

VIA E-MAIL: cynthia.wilsonfrias@puc.ri.gov

Cynthia Wilson-Frias, Deputy Chief of Legal Services
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Request for Comments on a Docket to Investigate the Changing Distribution System
National Grid Comments

Dear Ms. Wilson-Frias:

National Grid[1] is pleased to submit the following comments and recommendations to the Public Utilities Commission (PUC) Staff in response to your Memorandum dated February 5, 2016 (Memorandum) requesting comments and recommendations from interested parties regarding the scope of the docket to investigate the changing distribution system.

Background and Introduction

At its January 19, 2016 Open Meeting, the PUC announced its intent to open a docket on or about February 25, 2016 to investigate/review the changing distribution system. On February 5, 2016, you issued a Memorandum seeking input from stakeholders regarding the scope of the docket within certain parameters. Specifically, in your Memorandum, you asked the parties to address the following overarching question in their written comments: **What attributes are possible to measure on the electric system and why should they be measured?** You also asked the parties to address the following three subparts to this overarching question:

1. What are the costs and benefits that can be applied across all programs, identifying each and whether each is aligned with state policy?

2. At what level should these costs and benefits be quantified—where physically on the system and where in cost-allocation and rates?

3. How can we best measure these costs and benefits at these levels–what level of visibility is required on the system and how is that visibility accomplished?

The Company has organized its comments and recommendations around these four questions.

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

As a starting point for its comments and recommendations set forth in this letter, the Company has identified the following guiding principles and goals, which it has gleaned from your Memorandum, and offers some observations regarding normalization and Least Cost Procurement:

Principles to Guide the Parties Through the Stakeholder Process

- Ensure rates charged to customers continue to be just and reasonable across all programs and components of the bill;
- Ensure all programs are consistent with Rhode Island's Least Cost Procurement Standard;[2] and
- Ensure all rates are consistent with traditional Bonbright principles and new principles set forth in the Renewable Energy Growth Program statute.[3]

PUC Goals to Accomplish in This Docket

- Normalize Least Cost Procurement over all programs;
- Develop a unifying test for reasonableness across all programs: a single set of measurements by which all future programs funded through rates can be examined for reasonableness;
- Determine whether the differences between program incentives are reasonable;
- Determine whether the decision to implement a utility activity through one program or another is reasonable;
- Improve understanding of whether spending in one program efficiently and appropriately offsets spending in another program; and
- Ensure program spending and rates are set so that state policy goals are achieved at the lowest cost.

The Company recommends that the PUC articulate clear goals to accomplish in this docket and principles to guide the parties through the stakeholder process and generally supports the goals and principles outlined above in the context of the discussion presented below. In addition, the Company offers the following additional objectives for PUC consideration:

- Ensure that the normalization envisioned is flexible so that it can accommodate future opportunities;
- Given the evolving nature of the future electric distribution system, consider incremental steps that could be taken to help inform that future;
- Least cost should take into account administrative processes, which have an associated cost, and efficiencies; and
- The electric distribution company must have the ability to recover any prudently incurred costs subject to PUC review.

[2] See R.I. Gen. Laws § 39-1-27.7.
[3] See R.I. Gen. Laws § 39-26.6-24(b).

Observations Regarding Normalization and Least Cost Procurement

The Company offers some observations regarding the PUC's goal to normalize the systems, which fall under the Least Cost Procurement umbrella. First, it is not clear what the PUC intends to mean by "normalization". For purposes of the comments and recommendations contained herein, the Company has interpreted this goal to mean that programs should be consistent to the extent possible under the statutory framework of Least Cost Procurement. This is the Company's interpretation for the purpose of these comments. However, the Company recognizes that our interpretation may not be identical to PUC's intent. It is important to note that Rhode Island General Laws § 39-1-27.7 states that Least Cost Procurement,

> shall comprise [system reliability, energy efficiency and conservation procurement, and supply procurement pursuant to §39-1-27.8] as complementary but distinct activities that have as a common purpose meeting electrical and natural gas energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent and environmentally responsible.

Least Cost Procurement applies to electricity and natural gas distribution. By focusing its investigation on electric distribution, it appears that the PUC seeks to simplify the complex goal of normalization, recognizing that in doing so it is at the expense of some synergies and opportunities for least cost within Rhode Island's energy system.[4] If the PUC seeks to focus solely on electric system actions, the PUC may wish to consider a full range of benefits and costs associated with delivery of natural gas as well as the delivery of electricity, other fuels, and/or non-energy attributes. The Company also recommends that care be taken to avoid outcomes that would impede the ability for synergies to continue where they are already providing value to customers, such as the ability to offer joint electric and gas programs through the existing Least Cost Procurement framework. Other actions that are not directly related to the delivery of energy provided by the Company should be excluded from the regulated delivery company requirements. However, the PUC must first decide what is meant by normalization through discussions with stakeholders, including the Company.

As a threshold matter, the Company notes the challenge of attempting to normalize certain aspects of the electric distribution system under the Least Cost Procurement umbrella. In particular, there is a separate statutory requirement with a defined process and limits for the Company's electric and gas infrastructure, safety and reliability (ISR) plans, which are filed with the PUC annually following consultation with the Division of Public Utilities and Carriers and represent the Company's work plan for the upcoming fiscal year. The ISR plans have been successful in facilitating the Company's investment in utility infrastructure, safety, and reliability, which is one of the enumerated purposes set forth in Rhode Island's revenue decoupling statute.[5] This statute is separate and distinct from the Least Cost Procurement statute.

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[4] For example, blending across fuels such as in energy efficiency and SolarWise can potentially provide electric and gas use management in specific areas where it makes sense (i.e. wifi enabled thermostats).
[5] See R.I. Gen. Laws § 39-1-27.1(a)(7).

Least Cost Procurement in Rhode Island is a resource acquisition strategy for the procurement of energy at least cost, whereas the revenue decoupling law in Rhode Island seeks to remove the disincentive for the electric distribution company to make certain investments both in least cost resources, but also separately in utility infrastructure for safe and reliable service. Projects (both discretionary and non-discretionary) within the context of the ISR plans have matured well past conceptual stages, and often times are already active because these projects generally span several years prior to completion. By the time of the ISR filing, all considerations of distributed resources would have been analyzed and evaluated through the planning process resulting in an ISR Plan that requests spending only for specific distribution investments. In order to achieve the statutory objectives of the ISR plans, the Company's position is that the ISR plans should be excluded from the normalization process, and should not be considered as part of a unifying test for reasonableness and/or program offsets as these plans have already taken into account all commercially available customer side alternatives recognized through the distribution planning process.

There may be opportunities for normalization within the Company's distribution planning processes and guidelines. For example, the distribution planning process does currently account for distributed energy resources (DER - distributed generation, storage, localized energy efficiency, temporal load management, etc.). To achieve greater normalization, distribution planning processes and/or guidelines could be modified in the future once DER alternatives have been proven to provide needed, timely capacity reductions, and thus could be considered under the same framework. Such a process would facilitate the review of new, less mature technologies, such as grid self-healing technologies, distribution automation, advanced metering infrastructure, and advanced communications, allowing for the evolution of the distribution system over time, which in turn feeds into future annual ISR plans. This distinction between the ISR plans and distribution planning is reflected in the final Systems Integration Rhode Island Vision Document.[6]

The statutory framework for Least Cost Procurement also encompasses supply procurement as a complementary, but distinct activity. The Company recognizes the role that supply plays in the concept of least cost, both in terms of energy costs to end use consumers, as well as the explicit statutory requirement that the procurement of energy efficiency be less expensive than the acquisition of additional supply. There may be potential synergies to explore in terms of monetizing DER outputs, to offset costs to all other customers. The Company recommends that the PUC provide further guidance as to how broadly it wishes to explore this element of Least Cost Procurement.

Finally, the Company notes that the Standards for Energy Efficiency and System Reliability (Standards) currently focus on energy efficiency programs and technologies, as well as non-wires alternatives, but not on other customer-side resources such as distributed generation or demand response. The Standards update process, which is anticipated for the beginning of

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[6] See Systems Integration Rhode Island Vision Document, January 2016 (http://www.energy.ri.gov/siri).

2017, may be a potential venue in which to support the normalization process, and to develop a framework for specific technologies that would fall under Least Cost Procurement.

National Grid Comments and Recommendations

1. What Attributes Do We Currently Measure and Why Do We Measure These Attributes?

Currently, the Company measures a number of attributes associated with the electric distribution system. Please see Attachment 1 for a list of attributes currently measured on the electrical distribution system, as well as others that are capable of being measured. For energy efficiency programs, the Company measures electric energy savings, demand reduction, and natural gas energy savings. Attributes are measured to give an indication of the Company's efforts towards meeting state policy or regulatory goals, system performance, and allowed approved performance incentives. Recording metrics on available measured variables can be done. This effort could be done with the intention of creating greater understanding regarding actions behind the metric. However, there are costs associated with the recording of metrics and selection of variables to measure and report. Therefore, this should be done carefully, focusing on those metrics that contribute to improved customer efficiency in use of the system (such as those measurements performed for the energy efficiency programs) and improved service to customers. New metrics should be reviewed over time to ensure they are appropriate to use for any purpose other than informational. The focus should be on delivered results to customers in terms of safe, reliable service and new metrics should be considered carefully regarding their impact on existing metrics and customer service.

In addition, there are other attributes that cannot be measured currently but still provide some level of value to the electrical distribution system. Examples include resiliency from widespread outage events (i.e., Hurricane Sandy), safety, fuel diversity, customer acceptance of new technologies, greenhouse gas emissions reduction, and the value of the deployment of new utility driven technologies on the system, such as those listed above. The Company notes that some of these attributes not currently measured are identified in state policy and regulation, and encourage the PUC to consider areas where those policies overlap with Least Cost Procurement, and ensure that they are met cost effectively, to the extent possible.

Therefore, it will be challenging to see how these measurements would be incorporated into "… a single set of measurements … by which all future programs funded through rates can be examined for reasonableness …" The Company recommends that PUC, in the context of this docket, consider how all of the attributes (both measureable and non-measureable) fit into the overall distribution system, and examine both operational (present day) uses and infrastructure expansion planning (future) uses before trying to apply a single set of performance metrics across multiple programs. The use of a common matrix showing all programs and then attempting to align their respective costs and benefits amongst each other could be a good start for this effort. As mentioned above, it will be likely that some issues will not be directly comparable so should remain separate under modified programs.

2. What Are the Costs and Benefits That Can Be Applied Across All Programs and How Each Is Aligned With State Policy?

A sample detailed presentation of the costs and benefits associated with several system attributes is provided as Attachment 2, and may be helpful in illustrating where and how costs and benefits can be normalized and applied across all programs, and where there are gaps in the estimation of costs and benefits that may be worthy of further investigation. The Company questions whether full normalization of all costs and benefits across all programs is attainable because, for example, the full range of costs and benefits that a distribution planner considers is not, and is likely never to be the same, as what energy efficiency planners consider. Alternatively, there are individual programs that encompass several attributes – such as non-wires alternatives implementation, which spans both distribution planning attributes and DER and includes energy efficiency and demand response measures – but the benefits of those different processes are currently not fully aligned. Therefore, if full normalization of all costs and benefits is not attainable, a comprehensive system to look at disparate attributes thoroughly (i.e., how much, precise location, and specific time for each attribute) across a range of programs is critical.

In addition, there may be certain state programs related to energy, such as tax incentives or other forms of investment support, which complement the utility's programs but may not directly impact the costs to the electrical distribution system and, therefore, should not be included in rates under Least Cost Procurement. The Company recommends that the PUC examine and distinguish between state programs, the costs for which are appropriate to include in rates because advancement of those goals directly impacts the cost of operating the electric delivery system, and those that do not and, therefore, should not be included in electric rates

3. At What Level Should Costs and Benefits Be Quantified—Where Physically on the System and Where in Cost-Allocation and Rates?

The Company directs the PUC to Attachment 2 for an illustration of the different measurement systems currently in place. Integration and normalization of Least Cost Procurement will require a system of metrics. Today, the Company believes that some of these can be reliably monetized, some measured but not monetized (for example, reliability), and some not even measured (resiliency). It would be helpful for the PUC to provide guidance as to how much certainty is required, and what is the value of investing in technology today that may or may not pay off in the future, within the objective of Least Cost Procurement. For example, there may be locational value to the deployment of certain technologies or generation; however, the Company does not currently have the data to assess the locational value. To effectively and efficiently deploy capital on our distribution system, we may need to invest in new equipment as well as the necessary back office systems to distill out the effective actionable output from the raw data collected. Once equipment and systems have been deployed, analyzing the data could assist in determining locational values, if any. The Company suggests that demonstration projects are one way in which to determine what, if any, value can be realized from investments in new technology.

Regarding cost allocation, the distribution system is a capacity oriented system, yet costs are collected volumetrically. It would be helpful to understand which elements of Least Cost Procurement are volumetric oriented and which are capacity oriented. As the Company deploys increasing amounts of energy efficiency and distributed generation, appropriate cost recovery and allocation is necessary. The Company notes that, in Attachment 2, most of the benefit and cost categories across the various programs are associated with the addition of capacity to meet peak loads or reduction of peak loads as opposed to volumetric consumption. In this light, it would be valuable and instructive to look at current level of volumetric and demand components in the electric bill to determine if this is the right mix for billing going forward.

One of the PUC's stated goals is to "ensure that all rates are consistent with traditional Bonbright principles and the new principles set forth in the Renewable Energy Growth Program." The Bonbright principles provide the tools for how to allocate costs once incurred and are aimed at five key criteria: (1) economic efficiency; (2) equity; (3) revenue stability; (4) bill stability; and (5) customer satisfaction. Rate structures, which are revenue neutral, set the appropriate price signal, are simple and "avoid rate shock" to customers, and do not unintentionally subsidizing another consumer, meet the Bonbright criteria. The Renewable Energy Growth Program allows the PUC to take into account several factors when setting rates, which are consistent with Bonbright as well as other factors aimed at the advancement of the state's policy goals for facilitating distributed energy resources.[7] Reviewing all customers' needs and uses of the electric distribution system should allow the PUC to determine proper allocation of the costs that are required to construct and operate the system.

4. How Can We Best Measure These Costs and Benefits At These levels–What Level of Visibility Is Required on the System and How Is that Visibility Accomplished?

There are different ways to interpret "visibility" on the system. From the utility's perspective, there are several tools that would be needed to support visibility and be able to more accurately measure real-world success in the deployment of investments, technologies and resources on the electric distribution system. In addition, new resources would be required to incent customers to change their behavior under a "least cost" paradigm. The Company submits that a more robust stakeholder process and a specific discussion around this topic would be necessary before being able to fully respond to this question. With regard to performance incentive mechanisms, the Company recommends that visibility considerations apply to make sure that desired outcomes are clear, measurable, and effectively understood and within the utility's control or ability to influence.

5. Customer Bill Impacts

One of the goals of this docket should be to ensure program spending and rates are set so that state policy goals can be achieved at the lowest cost. The Company observes that state

[7] See R.I. Gen. Laws § 39-26.6-24(b).

policy objectives may vary from year-to-year. Thus, the PUC should consider how these objectives will factor into the amount that the state's consumers are willing to expend to achieve state policy goals. Additionally, it is unclear how customers will value some of the attributes discussed herein. The state may find itself in a situation where customer bills will be higher (and there will be no savings) to pay for societal benefits that provide a different stream of value to customers. Therefore, educating and incentivizing customers to "do the right thing at the lowest possible cost" is also an important consideration.

The Company looks forward to future discussions with the PUC, Staff, and other stakeholders regarding this important docket.

Respectfully submitted,

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ATTACHMENT 1

System Performance Attributes That Are Measurable*[1] (All from a distribution planning perspective):

1. Service Reliability – Measures how well we are delivering the vital service/commodity electricity is to our customers. Useful and/or required measurements exist at the transmission supply level all the way to the individual customer level. Important levels to note are – Customer, individual protective devices (branches), circuit (feeder), substation, and supply.
2. System Loading – Monitoring supports system operations in real time, the forecasting of future system loading variations, and subsequently the planning of infrastructure development. Useful and/or required measurements exist at the transmission supply level all the way to the individual customer level. Important levels to note are – Customer, individual protective devices (branches), circuit (feeder), substation, and supply. Important quantities – Watts, VAR's, Amps (individual phases and three phase)
3. Load vs. Capacity – Calculated. When system capacity to serve load or receive generation is being reached, system operations becomes more challenged (both normal and during contingency response) which can negatively impact service reliability. If capacity is exceeded, there is increased probability of equipment failure. Load vs. capacity should be able to be calculated for every element on the electric system.
4. Voltage Performance – Voltage must be maintained within a certain "acceptable" range for customer equipment (ex. computers, refrigerators, ovens, etc.) to operate properly. Useful and/or required measurements exist at the transmission supply level all the way to the individual customer level. Important levels to note are – Customer, individual protective devices (branches), circuit (feeder), substation, and supply.
5. Reactive Performance – This is more a measure of system efficiency. The management of reactive resources on the electric system impacts voltage, load vs. capacity, and losses. Its direct measurement is required only in locations where load vs. capacity can become a critical bottleneck and impact system reliability.

System Performance Attributes Capable of Being Evaluated[2]

1. Asset Condition – Important to consider from both a service reliability and operations safety perspective.
2. Operational Flexibility – Important to consider because it can greatly impact service reliability (outage durations).
3. Losses – Moderately important consideration that impacts system demand/utilization.
4. ArcFlash compliance/levels – New operations guidance from OSHA that needs to be taken into consideration in the scoping of infrastructure development projects.
5. Resiliency – Developing consideration that will impact future infrastructure development project scopes.

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[1] Although measurable, National Grid may or may not measure these quantities at these levels in the system today (or, in all areas of the system). Also, if measured today, quantities may not be available in real time.
[2] System performance issues identified with these measures are given essentially equal priority to those in the prior list when developing infrastructure development projects included in the ISR.

Draft framework for comparison of attribute-driven benefits and costs across programs and system levels.

			Program						
Attribute Measurement or Evaluation Level	**Benefit/Cost Category**	**System Attribute Benefit/Cost Driver**	**Energy Efficiency Program**	**System Reliability Procurement (SRP)**	**Infrastructure, Safety, & Reliability Plan (ISR)**	**Renewable Energy Growth Program (REGrowth)**	**Renewable Energy Standard (RES)**	**Net Metering**	**Other programs and policies, e.g. Standard Offer Supply Plan, Retail Choice, Ratemaking, Interconnection Standards, Environmental Regulation, Utility Financial Incentive**
Bulk System Level	Generation capacity costs (FCM)[1]	coincident peak demand							
	Energy supply costs (LMP)[2]	energy to serve load							
	Transmission capacity infrastructure costs	coincident peak demand							
	Ancillary services costs								
	Energy DRIPE[4]	energy to serve load							
	Capacity DRIPE[4]	coincident peak demand							
	Greenhouse gas emissions costs (Avoided RGGI price embedded in LMP)[3]	energy to serve load energy supply mix							
	Criteria air pollutant emissions costs (avoided compliance costs embedded in LMP)	energy to serve load energy supply mix							
	Non-energy costs/benefits (e.g. economic development)								
Distribution System Level	Distribution capacity costs	local peak demand asset age/condition							
	Distribution operation and maintenance costs	energy to serve load							
	Ancillary services costs								
	Distribution system reliabilty loss/gain	local peak demand asset age/condition energy to serve load							
	Distribution system resiliency loss/gain								
	Distribution system safety loss/gain								
	Program administrative costs	participation requirement incentive requirement							
	Non-energy costs/benefits (e.g. economic development)								
Customer Level	Program participant costs/benefits	behavior requirement technology requirement							
	Program non-participant/benefits								

[1] FCM refers to the ISO New England Forward Capacity Market (see, http://www.iso-ne.com/markets-operations/markets/forward-capacity-market).
[2] LMP refers to the locational marginal price of energy (see, http://www.iso-ne.com/participate/support/faq/lmp).
[3] RGGI refers to the Regional Greenhouse Gas Initiative (see, http://www.rggi.org/).
[4] DRIPE refers to "demand reduction induced price effects."