nationalgrid

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VIA ELECTRONIC MAIL

Rhode Island Power Sector Transformation Initiative
c/o Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources
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RE: Rhode Island Power Sector Transformation Initiative
Notice of Inquiry into Distribution System Planning and
Request for Stakeholder Comment dated June 2, 2017
National Grid's Responses to Questions Related to Electric Distribution System

Dear Members:

On behalf of National Grid,[1] I enclose the Company's responses to the stakeholder questions outlined in the Division of Public Utilities and Carriers and the Office of Energy Resources Inquiry into Distribution System Planning and Request for Stakeholder Comment dated June 2, 2017.

The Company looks forward to future discussions on these important inquiries. If you have any questions, please contact Kayte O'Neill at 781-907-1790, Tim Roughan at 781-907-1628, or me at 781-907-2153.

Very truly yours,

Celia B. O'Brien

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Enclosure

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

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Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources
Power Sector Transformation

Notice of Inquiry into the Distribution System Planning and Request for Stakeholder Comment

Responses of National Grid to June 2, 2017 stakeholder questions

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SECTION 1. WHAT SHOULD BE THE KEY ELEMENTS OF DSP?

One important step to establish the future direction of DSP is to identify the necessary elements of DSP. The potential elements of DSP for a twenty-first century utility may include:

- *Forecasting*, where energy demands are projected on the system to determine future peak requirements.
- *Power flow analysis*, to test whether the existing system can accommodate forecasted demands and maintain voltages within established standards.
- *Condition assessments*, to determine the health of system components and develop replacement strategies before failure.
- *Solution identification*, where options are selected to address identified needs – the solution could be an operational change by the utility operator (e.g., reconfiguring a feeder), a traditional utility infrastructure project (e.g., a new feeder), a "non-wires" alternative (e.g., customer investments in energy efficiency, renewables, or storage), or a combination of any of the above.
- *Hosting capacity analysis*, to determine the maximum amount of distributed energy resources (DER) that a substation feeder can support without additional upgrades.

The electric utility performs many, but not all, of these elements of DSP today. As technology improves and learning occurs over time, the electric utility will be able to improve features of each DSP element to better achieve the objective of supporting an optimized deployment of resources on the system that provide maximum net benefit to customers, the system, and society.

Questions for stakeholders on DSP elements

1) How important are each of the DSP elements described here to the future electric utility? Are there additional elements not described here that should be included as a strategic focus of the electric utility? What does success look like for each element?

All of the functions discussed above are important to the future electric utility's ability to provide an efficient, safe, and reliable electricity delivery system. Comments on the individual functions follow.

- *Forecasting:* As has been discussed at various technical sessions throughout the SIRI process, and in discussions throughout the Docket 4600 process, the Company takes into account forecasted DERs (i.e., energy efficiency and expected amounts of distributed generation from the renewable energy growth program as well as net metering projects) in its short- and long-term load forecasts. Due to these measures, load growth is quite low, and is projected to remain low for many years. Accordingly, locations on the distribution system where DERs could provide value can be difficult to locate. As DER penetration increases, locational and statewide forecasts will need to become increasingly granular. A statewide forecast of peak hour net demand will not be sufficient for future distribution planning with high penetrations of DER. While some types of DER (energy storage) can be expected to reduce the overall peak hour loading, many other types (solar, wind) will not affect peak loading as the peak continues to move later in the day (during the recent hot weather, 6/11 to 6/14, ISO system peaks have been at hour ending 5 p.m.). The impact of DER on distribution system operations must be understood across a wider temporal spectrum, particularly solar DG which may impact the distribution system at light load periods more so than at peak load periods. Therefore, load and DER forecasting for distribution needs to become more granular in both temporal and geographic fashions. It will also be important to understand the contributions of DER to the overall net load so that the econometric and weather variables can be applied appropriately in forecasting.

- *Power flow analysis:* National Grid recommends framing the discussion more broadly to focus on System Assessment, which includes power flow analysis. Power flow analysis tests whether the existing system can accommodate forecasted demands under normal and contingency (the ability for one feeder or substation transformer to pick up loads in the event neighboring feeders or transformers are out of service for any reason) configurations as well as reviews of system voltage performance, protection system coordination, reliability, reactive compensation, and fault current levels. Enhancements are necessary in the data, tools, and methods used for performing power flow analysis. Today's tools and approaches are deterministic and generally perform a power flow assessment on a single, static, scenario (such as peak-hour loading). In the future, the performance of the system must be evaluated under many scenarios and tools to efficiently perform assessments. Additional tools to streamline these complex computations and perform the necessary analytics of much larger volumes of data will be needed. The Company, along with the rest of the international utility industry, still awaits easy to use modeling tools from software vendors that properly represent the significant dynamic nature of high saturation of DERs on the electric distribution system. The tools are being developed, but much work needs to be done to provide an efficient review in a timely manner and to provide needed updates at whatever frequency is desired or required.

- *Solution identification:* In addition to the description above, solution identification also requires detailed operating and economic modeling tools to evaluate the Benefit/Cost analysis of alternatives along with the evaluation of expected performance of solution alternatives. The challenge is the use of the Docket 4600 cost benefit matrix, as distribution investments historically solved a distribution need through analysis of typical utility options at lowest cost with the required list of attributes such as replacement of older unreliable equipment, significant worker and public safety improvements, measurable operational and therefore reliability benefits, etc.

- *Hosting Capacity Analysis:* An analysis of this kind can be difficult to undertake as there are not simply loading considerations for proposed DG, but also the required coordination of protection strategies that need constant updating with every new DG system installed. In addition, the analysis quickly becomes out-of-date as the aggressive state DG policy goals result in many DG applications coming in on a monthly basis. With that said, a process to develop some level of hosting capacity could be put together as long as all parties are aware of the inherent limitations of the information.

Regarding additional elements for strategic focus, Distribution System Planning must be adapted to provide direction and operational clarity on the strategic implementation of beneficial functionality as suggested by the parallel Grid Connectivity work stream to provide a clear road map to allow for full grid modernization in RI. Such functionality includes volt/var optimization, distribution automation, and sensor deployment (including Advanced Metering Infrastructure) and their enabling communication systems. In addition, metrics around progress for more user transparency into the DSP process should be developed at a pace appropriate to the Company's ability to develop this new process while making sure critical day to day distribution planning activities are conducted. These technologies would further advance the three state objectives described in the Introduction to this Notice of Inquiry.

Success is achieved for each element when they serve to support an evolution of the DSP that enhances system safety and reliability while supporting the provision of new opportunities to customers.

2) Utility investment in grid modernization capabilities will provide increasing visibility into the system, allowing a more sophisticated and granular approach to DSP. What should the future state of planning look like as visibility improves? What should the transition look like between current DSP and the future state of DSP?

Under a future state of DSP, where the strategic concepts described in 1) above are implemented, system assessment would be enabled to analyze, predict, and provide for significantly more transparency in an evolving two-way distribution system. This level of transparency will allow for more market-based solutions as well as individual customer actions to provide potentially lower-cost solutions in the future. With minimal load growth predicted, the level of customer involvement will take time to develop. The future state of DSP will require more knowledge transfer to get the market and customers to understand the critical importance of how they can participate in the multiple facets of solving system needs, which looks at much more than simply peak loading.

National Grid believes that DSP transition should be continual and appropriately phased with incremental enhancements prioritized with extensive stakeholder engagement.

SECTION 2. HOW SHOULD DSP OFFER TRANSPARENCY WHERE APPROPRIATE TO RELEVANT UTILITY, MARKET, AND POLICY ACTORS?

As clean energy technologies become more widespread and affordable, growing numbers of consumers choose to invest in their own on-site energy reduction, management, production, or even storage. In doing so, these customers may impose incremental costs or help reduce costs on the electric grid. The nature of the impact varies based on technology type and location of the investment. For example, if enough customers implement energy efficiency projects on a given feeder, the cumulative impact could defer the projected need for a system capacity expansion project. A similar benefit could be achieved through customer adoption of rooftop solar, depending on the orientation of the systems and the type of capacity need. On the other hand, deployment of solar in a different location might require circuit upgrades if the existing distribution system cannot accommodate the new generation. Access to data – system data and customer data – could help customers become resources towards meeting grid needs and maximizing the net benefits of customer investments in clean energy technologies. For example, clean energy companies *might be able to use information on the location and characteristics of grid needs to target offerings to customers located in beneficial areas. The ability to retrieve customer data – with the proper privacy and security protections in place – could allow clean energy companies to tailor offerings to customers or for customers themselves to take action on their energy use.*

Questions for stakeholders on DSP transparency

1) Who are the users of system and customer data? What data do users need to guide investment decisions, support business models, or guide policy/program activities? What are the specific use cases for each dataset? What is the desired format of each dataset? What is the frequency with which datasets should be updated?

DER providers, developers, and aggregators, some advocacy groups, and regulators are all potential users of system and/or customer data. It may be unlikely that individual customers (except for very large and sophisticated consumers) will want or will exert the necessary effort to obtain the data, or that they would sufficiently analyze the volume of data necessary to become a resource towards meeting the grid needs. Instead, customers may be focused on controlling or reducing their own energy requirements. For these purposes, even though a basic level of usage data is currently available to all customers, a needed investment in advanced metering functionality for all customers would provide significantly more granularity of usage and operational information needed for enhanced market participation.

Data needs for each stakeholder are likely to vary. Each stakeholder should identify their data needs and use-cases as specifically as possible. Once these are gathered, a State-directed effort could consolidate these requests. In collaboration with the Company, this effort could determine which data should be provided, the appropriate timeframe for providing the data, and the appropriate format.

Managing data for the needs of external parties will require additional resources at the utility as requests of this sort are typically managed on demand and in discrete volumes to address identified issues. Providing all data, on a constant basis, to be used for undefined purposes (use cases) could be costly and time consuming for the utility. Therefore, as discussed above, the Company recommends that the state initiate a formal process to determine guidelines for data provision. It is important to note that currently, most data management for distribution planning is a manual effort. Investments in data management are likely to be necessary to support efficient provision of data.

2) What are the key data access safety and security considerations? How should customer privacy be protected? How will the utility's requirement to protect the grid and maintain sensitive information be balanced with the need for more visibility?

The most important safety and security considerations include customer privacy, critical energy infrastructure information (CEII), and cyber security. As distribution feeders are typically only capable of serving 8-15 MWs of load, significant point loads and usage characteristics that represent large customers can compromise proprietary business processes. Any information about the time of, and amount of usage, can readily disclose when customers at are home or at their business, potentially exposing them to opportunistic individuals and enterprises who can take advantage of the unoccupied building. The Company prides itself on the level of customer privacy already in place to which it would continue to adhere to make future levels of information as protected as required by applicable laws, including without limitation the Rhode Island Identity Theft Protection Act of 2015 (R.I. Gen. Laws Chapter 11-49.3) and/or Company policies and procedures.

With respect to customer privacy, as has been suggested in filings in NY, the utilities have proposed a 15x15 standard. No data can be shared publically where the data involves less than 15 customers AND where no one customer represents more than 15% of the load. Other options include registration processes, user vetting, and non-disclosure agreements.

The balance between information security and additional visibility are likely to be best achieved through clear standards with regulatory oversight, and significant penalties for violating these standards. This could include a registration process that pulls data users under the jurisdiction of the regulator. In New York, these questions are currently being addressed through proceeding on Uniform Business Practices considering the issue of who would fall under regulatory jurisdiction.

SECTION 3. WHAT SHOULD THE DSP PROCESS LOOK LIKE?

Currently, the electric utility performs DSP in house. Stakeholders may see certain outputs of DSP in PUC docket proceedings, namely the Infrastructure, Safety and Reliability dockets and the System Reliability Procurement dockets. However, there is no regular docket proceeding or filing associated with DSP activities specifically.

Questions for Stakeholders on DSP process

1) What DSP information – such as information associated with the DSP elements identified earlier in this document – should be made available to users, including the market, regulators, and policymakers?

At the broadest level, the Company should provide any information available that would not violate any applicable Rhode Island law, customer privacy rights, divulge CEII, or increase the risk of malfeasance beyond acceptable risk profiles to promote market activity than could provide cost effective opportunities. However, the regulatory framework must support stringent privacy considerations, strict adherence to all applicable Rhode Island laws or needed regulation, swift recourse for market actors who prey and/or take advantage of customers, as well as compensation for the elevated efforts for the Company's efforts to maintain the highest levels of customer privacy and choice. In the course of providing any customer data with specific written consent, the Company should be compensated at market rates, rather than simply recover costs, for the provision of "value-added" data that supports competitive market activities. This "value added" data" does need specific definition, and the Company supports a working group to aid in this definition, however as the holder of the data, any definition and/or process must minimize the potential cost risk of data sharing to the Company.

2) How often should this information be made available and in what format? Should this information be compiled in a new DSP docket proceeding (or filing within an existing docket)? How should any new DSP filings be coordinated with ISR and SRP? How should they be coordinated with any other applicable filings?

Whatever format is determined to be appropriate through the State-led process described above, it will likely take significant effort on the Company's part to mine, present, and protect the data in that format and address data gaps identified by that format. There is no need for a separate DSP 'docket' or proceeding, as the current SRP process already has DSP at its core. In addition, there is significant flexibility in the ISR process as a venue for any requested transparency of DSP. As previously stated, the frequency of information publication or refresh through both the SRP and ISR should follow a step-wise improvement or phased evolution towards the final desired state. Appropriate metrics on providing data could be developed once the overall process and specific data needs have been established.

The Company is receptive to whatever process regulators believe is the most effective approach for making information available considering time, cost, and resources. As stated in many proceedings, a DSP review needs to happen in advance of inclusion of its recommendations in either the ISR or SRP. For example, a FY19 DSP review would be done to advise FY20+ ISR or SRP filings through the planning needed for FY19 SRP and/or ISR projects.

3) Utility DSP must take into account both current and long term system impacts. Solutions require multiple years for design and implementation. How will the utility and stakeholders coordinate efforts to develop solutions, particularly those that are implemented by customers and not controlled by the utility, such that there is certainty of implementation before system operational issues arise? How will a "safety net" be implemented to ensure that the utility can implement solutions (traditional or NWA) if third party commitments fail, particularly when there are long lead times for implementation?

Operational coordination challenges of the type described are one of the fundamental reasons regulated electric utilities were formed. The coordination challenges are significant and raise the question if participants should be required to satisfy safety and reliability issues in a similar manner as the regulated utility. As the only party responsible for an efficient, safe, and reliable distribution system, the utility should coordinate efforts under the direction of the regulator or the regulator could take the responsibility for coordination. The "Heat Map" is one example of an approach that may mitigate the risk of inefficient coordination through utility control at the direction of the regulator. This approach potentially allows DER to take action prior to National Grid's application of its formal distribution planning criteria. The utility would observe external stakeholder response, implementation, and results. The results would be incorporated into the utilities normal system assessment. A second example could be engaging DER providers earlier in the planning process (potentially at "Needs Assessment" or "Technical Review" milestones) through RFP or RFI. This will require diligence on the Company's part to provide the time in the planning process to consider the DER opportunities and it will require significant effort from DER providers to engage well in advance of any potential financial opportunity.

In addition, the use of the “Heat Map” would support strategic electrification policies. In this way, the Company would determine the locations on the system that would likely not require significant or any upgrades to accommodate increased electric use for EV charging stations.

Regarding a “safety net”, third-party commitments should be held to the same standards as traditional utility investment. Third-party providers should guarantee performance. Lack of performance could result in third-party penalties, and the Company should not be penalized for undertaking new, innovative market solutions that are ultimately proven to not fully satisfy required criteria In addition, any “safety net” (risk mitigation) provided by the utility should be paid for by the third-party for failure to perform. As previously discussed, due to the very low load growth in the state, the “Heat Map” concept above will likely be more a flexible approach to third-party performance execution versus a targeted NWA due to the lack of deferral projects which are typically load growth only infrastructure improvements in the DSP process.