HANDY LAW LLC

Memorandum
From: Seth Handy
To: Danny Musher
Date: August 2017
Regarding: Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources Power Sector Transformation Supplemental Q&A and Comments on Distribution System Planning

I respond on behalf of Handy Law. We are not representing New Energy RI with regard to these proceedings at this time.

Supplemental Questions for stakeholders on Distribution System Planning

1. **Questions & Comments on RI Data Portal System**
   - What key information, data, or tools would stakeholders like to see on a RI System Data Portal? *In our view, the most important goal of the portal is to be transparent about system conditions so that regulators, stakeholders and the market can help manage the system to facilitate the new energy economy that is anticipated in these proceedings. The utility's black box planning has not maintained or enhanced the system condition in ways that facilitate and perpetuate the distributed energy economy we've envisioned. Hopefully, with better access to information and better stakeholders and regulators can help guide better system investment decisions. Any information that facilitates that kind of understanding and process will be especially valuable. Also need information regarding threats to system security and strategies to address them.*
   - The Power Sector Transformation team current vision is a modular portal that could be developed in an iterative fashion over time. What initial content or features should be prioritized for a portal? *See reply above.*
   - *Added comment: The utility should not oversee or administer the Data Portal System unless and until incentives are properly reframed per the Utility Business Model process.*
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2. **Questions & Comments on Data Access & Governance**

   - In its Supplemental DSIP Filing in New York, National Grid provides a list of datasets in publicly-available filings. Should any additional datasets be provided initially by the utility? *We don't have time to review and comment on this.*
   - How should a dataset be determined to be "value-added" and subject to payment by a user to access the data. Is this determined by the utility? By regulators? Other? *We do not agree that the utility should be allowed to charge for access to this data. Transparency of information is an essential*

element of ensuring that it is fulfilling its fundamental obligations & it's fundamentally not possible to gauge an incentive that both properly motivates the company and is fair to customers. It's one thing to allow utilities to earn income, or a rate of return, from the successful provision of grid services from non-utility owned DERs but quite another to charge customers for access to information they must have to understand and plan their system.

- Aggregation standards can be used to preserve customer privacy. Aggregated data is data that has been summed or combined across a group of multiple accounts in order to preserve individual customer privacy. In New York, the utilities proposed a 15/15 privacy standard for aggregated data, which would require data to be drawn from a minimum of 15 accounts and limits the load of any single account to 15% of the total load for the dataset. What is appropriate for Rhode Island? *These stated privacy interests are overstated and obstructive in this context. Obstructing access to information only undermines our capacity for control, analysis and system improvement. Any concerns from sharing such data – such as customer privacy, security, data quality, and qualified access – can be mitigated through data sharing practices already common in other industries. In fact, stakeholder engagement and access to planning data is already a central tenet in electric transmission planning across the country. The challenges of ushering a new industry norm of data transparency are far outweighed by the potential that broader data access can drive in increased stakeholder engagement and industry competition. A standard set of comprehensive data should be shared about each grid need and planned investment so that stakeholders can proactively propose and develop innovative solutions to those needs. This proactive data access broadens the set of innovative solutions made available to utilities and guards against an insular approach to deploying grid investments. While data on specific utility-identified grid needs is critical to assessing innovative solutions in place of traditional investments, underlying grid data should also be made available to foster broader engagement in grid design and operations. Access to underlying grid data allows third parties to improve grid design and operation by proactively identifying and developing solutions to meet grid needs, even before they are identified by utilities. Data that is made available on grid needs and planned investments is rarely provided in an accessible format. Often, information is provided in the form of photocopied images of spreadsheet tables within utility GRC filings, hardly a format the enables streamlined analysis. This data communication approach requires stakeholders to manually recreate entire data sets into electronic version in order to carry out any meaningful analysis, a time-intensive and needless exercise. Other potential stakeholders never attempt to engage due to the barrier of data access.*
- *Added comment: The utility should not oversee or administer Data Access and governance unless and until incentives are properly reframed per the Utility Business Model process.*

3. Questions & Comments on Heat Map

- What are the uses and objectives for hosting capacity analyses that are most important to Rhode Island stakeholders (e.g., indicative information for

feeder capacity for DER, fast- track interconnection approvals, annual distribution system studies)? *RI needs to start viewing its system comprehensively to determine how and where distributed energy resources can best be implemented to benefit customers, the system and society. To us, this is not principally about the specifics of existing system capacity (where DER can diffuse constraints or access capacity) as much as envisioning tomorrows grid and planning to accommodate that vision. We absolutely need heat and capacity maps to determine where we stand now, but that's only a starting point & we need to deploy those maps to design and implement the system we want to have/be. The emergence of new analytical software tools is helping to make portfolio-scale energy assessments easier and more cost effective, both for cities and for other large portfolio owners. RMI examined the use of these software tools to support the portfolio- assessment process and concluded that these new analytical software tools are helping to make portfolio-scale energy assessments easier, although the process does present challenges as well.*

- What are the granularity, frequency, and accuracy requirements for each use and appropriate industry method? *No comment.*
- How should the utility ensure consistent integration of heat map implementation across all DER and infrastructure planning processes? *By implementing the cost benefit analysis and other recommendations from Docket 4600 across all existing planning processes and designing new processes or redesigning existing processes to achieve the goals we've set*.
- How often can/should heat and hosting capacity maps be updated now and in the future? *They should be updated on a real time basis as information is received and integrated.*
- *Added comment: The utility should not oversee or administer the Heat Map System unless and until incentives are properly reframed per the Utility Business Model process.*

4. Questions & Comments on Forecasts

- Would making forecasting assumptions and methodologies available through ISR/SRP filings meet the needs of stakeholders to provide meaningful input into forecasting while balancing the Company's internal needs to meet their timelines and general obligations for distribution planning? *One problem with historic forecasting is that it's been exclusively focused on load and hasn't addressed constraints and opportunities associated with distributed energy solutions. We have serious concerns about whether the cited, existing planning processes, as currently administered, are adequate to address our needs for future system planning. See, for example, our recently drafted letter expressing the substance of such concerns to the EERMC and this filing/proceeding regarding the ISR -* *http://www.ripuc.org/eventsactions/docket/4539-WED-Coventry-Objections_2-10-15.pdf; http://www.ripuc.org/eventsactions/docket/4539-NGrid-Ord22174_10-21-15.pdf* (pp. 25-26). *We should not feel bound by existing legislative treatment or administrative structures in a vigilant pursuit of the modernized grid we need. While we hope that a reformed utility business model will help better align interests in sound long term system planning, it may very well not be enough.*

- *Added comment: The utility should not oversee or administer forecasts unless and until incentives are properly reframed per the Utility Business Model process.*

5. **Questions & Comments on Alignment of DSP, Capital Project, and Non-Wires Alternatives (NWA) Planning**

- How can DSP fully integrate partial NWA opportunities in a way that allows DER providers to provide incremental value to the system where opportunities exist? *As stated in previous comments, it's absolutely essential that our planning must be done comprehensively for our entire system and not in a compromised effort to implement incremental solutions. Cost effectiveness will come with scaled thinking, not with tinkering around the edges. We need to employ the stakeholder consensus recommendations from docket 4600 to fully evaluate the needs and opportunities facing our entire distribution system. We cannot plan for the future until we figure out how to fully value DERs. Historically, the electricity system has not fully valued DERs in distribution system planning and investment, despite potential benefits of DERs to the grid. While some utilities have employed DERs to modify peak loads and reduce wholesale peak costs, DERs can provide other services that may not been fully accounted for. In fairness, utility companies may not have fully leveraged DERs in part because the regulatory framework guiding utilities' business model did not explicitly orient the utility to recognize that value. Now that is changing. Utilities should employ open and transparent planning processes that consider the risks, probabilities, benefits, impacts and applications of multiple energy resources under various scenarios. Planning processes should include a full commitment by utilities to implement cost-effective energy efficiency and renewable energy. Resource planning should involve greater stakeholder involvement on a wider regional level and consider the full spectrum of energy efficiency and distributed energy resources. Clear policy frameworks allow all parties to better understand the goals and regulatory objectives that will influence or constrain the planning process. Finally, utilities should update planning processes to reflect current and future values of CO2, energy efficiency, distributed energy resources, equipment and permitting.*
- How and when should DER providers and/or other stakeholders be engaged through the distribution planning process? *As stated above, stakeholders need to have full access to information and be given the capacity to participate in all system planning processes. Challenges to this simple concept abound, whether it's the complexity and commitment of resources needed to be fully informed and effective in these proceedings (an effort and resources that the utility charges to its customers) or biases in federal/regional incentives that raise external threats to balanced thinking/planning and plan implementation (e.g., cost socialization of transmission investments but not grid improvements to facilitate DER). RI needs to devise a means of ensuring all stakeholders have full opportunity to be involved in these proceedings and to help shape them for our collective, future benefit. Ensuring that all stakeholders can participate in the identification of needs and design and implementation of solutions to ensure that process is not framed by any specific interest other than maximizing value to the system, the customer and society. Removing any conflict of interest that causes incumbent utilities to prefer building new infrastructure to conservation, efficiency, or local power from competitors or even utility customers. Proactive system planning is the key. As the SIRI report states:*

Discuss with electric distribution planning staff at National Grid ways to address a gap in stakeholder engagement. Start by confirming the set of interested stakeholders (e.g. OER, the EERMC, and the DG Board), then identify or create opportunities outside of PUC dockets for these stakeholders to engage with the utility on distribution investments pertaining to load growth. Concurrently, determine if and how distribution planning/SRP can be coordinated with net metering to offer enhanced incentives above what is currently available to promote the development of DG where it is most needed, if determined to be cost-effective. Work with National Grid distribution planning to determine how and to what extent forecasted DG from REG, net metering, and any other applicable renewable energy promotion processes can be incorporated into distribution planning. Also consider how this can be done for other forms of DER and for strategic electrification in the longer term. Ensure that any resulting information from above is coordinated with Grid's current "long-range capacity plan" and future distribution planning where appropriate. Gain an understanding of how the long-range capacity plan and ISR could be used to merge traditional "poles and wires" approaches with new technologies in a multi-year, strategic approach. Explore the role that robust measurement and verification processes have in distribution planning to enable planners to better understand the costs and benefits of capital investments and technology deployment, ultimately as a basis for informing future decision-making. Work with National Grid to better understand the overlap between "asset condition" and "load relief" projects as identified in distribution planning and proposed in the ISR. Understanding the dynamic between asset condition and load relief projects is necessary information for the future update of the Standards to potentially open up more projects to NWA eligibility.

- *Added comment: The utility should not oversee or administer any of these planning processes unless and until incentives are properly reframed per the Utility Business Model process.*

6. Additional Comments on the Draft Plan

- *We must ensure that we are not limiting our perspective on potential system enhancing value just because the current capacity of the system is not able to support the implementation of enhancements that will ultimately maximize that value.*
- *We'll need to use microgrids and broad, community-wide planning to make the most of our opportunity for DER and beneficial electrification of our thermal energy supply. Thinking small does not achieve either the scale or the level of economic benefit we seek.*
- *To achieve the goals of least cost, least risk and maximum customer benefit, regulators must require utilities to synchronize their implementation of advanced grid technologies with the growing DER market. Utilities perform this planning function today, but not usually in the public arena and not closely coordinated with other actors providing services on an upgraded distribution grid. This planning exercise is now loaded with new responsibilities for the grid operator. Further, if the utility also has a stake as a competitor with DER services, it is essential that an independent authority such as the state regulator oversees the planning. Consider the telecom sector following the passage of federal legislation in 1996. Incumbent carriers were required to unbundle their grid (the public switched network) and provide access to new players with new products, often competing with the grid owners. Regulators ensured that new competitors got*

access to the network on the same terms as the incumbents. Regulation of all players moved significantly away from the traditional cost-of–service model.

- *We must do the work to ensure that regional and federal policies are aligned with our interests in amore diverse and distributed energy system. Utilities have every incentive to operate existing and new capital assets for as long as possible. When the payments for construction are fully depreciated, the low operating costs of existing infrastructure makes utilities reluctant to shut down power plants or power lines when they can still earn revenue in operation, even when they are no longer in the public interest. One of the central governing rules of interstate transmission – FERC Order 1000 – was supposed to create a meaningful evaluation of non- transmission alternatives to new power lines. But the rule only requires that a utility consider alternatives proposed in the process, it does not obligate them to offer alternatives. In other words, to have a meaningful debate of alternatives requires a dedicated third party – a state agency, commercial or industrial customer, or nonprofit – to show up to contend with a utility's transmission line proposal on its own dime. Participation by third parties is remarkably onerous. For an outside entity to offer a transmission alternative, they have to request access to data about grid operations that many utilities shield as "trade secrets," be able to competently model the grid impact of a non-transmission alternative without access to the same proprietary software package or trained engineering staff used by the incumbent utility, and then cast the alternative in the technical and legal language expected at a regulatory proceeding. Alternatives to transmission projects face another hurdle: compensation. While FERC has established rules for sharing the cost of transmission lines along the route they extend, non- transmission projects have no such cost allocation process. Not only is it difficult for non-transmission options to share costs, but utilities frequently receive federal incentives for high voltage transmission lines that cross state boundaries. The overseer of these bonus payments – the Federal Energy Regulatory Commission – has doled them out to 4 of every 5 requesting utilities, resulting in an average return on equity of 13%. Finally, the federal overseers of transmission projects don't consider any non-grid benefits that would weight a decision toward a transmission alternative for serving grid needs. For example, while Vermont state regulators consider a wide range of benefits in their cost-benefit calculation of energy efficiency improvements (shown in the following chart), only a small slice of the benefits (in blue) would be considered by federal transmission planners, even though energy efficiency can meet the same needs for reliability and grid capacity.*