HANDY LAW LLC

Memorandum
From: Seth Handy
To: Jonathan Schragg
Date: October 19, 2017
Regarding: RIDPUC & OER Power Sector Transformation Section Comments on 10.13.17 Drafts

Thanks again for convening this process, allowing our participation/contribution and all the good work done on it to date.

Utility Business Model

- We ought to be sure we've evaluated whether this proposed restructuring has been evaluated in light of the goals of the important stakeholder/consultant process that led to the development of the State Energy Plan. One goal of the plan is to enhance energy security by diversifying our supply of electricity. On Page 38, the Plan summarizes that goal as follows:

> Energy 2035 defines fuel diversity as a risk management strategy that seeks to mitigate the potentially harmful effects of disproportionate reliance on certain fuels by expanding the portfolio of demand and supply sources used to provide energy services. Fuel diversity is measured here in terms of percentage market share of the dominant fuel source in each sector. For the electric sector, this percentage is measured in terms of in-state generation plus electricity imports, with the sources attributed to imports prorated by each source's share in the overall regional mix. . . Although many indicators of energy security are difficult to quantify, fuel diversity is a reasonable proxy for other security measures of adequacy, safety, reliability, and resiliency. Fuel diversity can help achieve the Plan's security goals via the following mechanisms:
>
> - Increased system redundancies
> - Increased consumer choices
> - Reduced impacts of price volatility
> - Decreased potential harm of supply disruptions
> - Increased potential for synergistic energy resources

Are those energy security goals adequately reflected in the proposed, new incentive structure? As set out in our earlier comments, in California, AB 327 requires IOUs to file DRPs that include scenario-based planning as well as integration analyses. Scenario-based planning accounts for different DER adoption scenarios, as well as other factors that might impact the need for DERs, such as retirement of large power plants. The CA IOUs are required to define the criteria for determining what constitutes an optimal location for DER deployment, and then identify values for the deployment via online mapping tools. The IOUs are also required to conduct integration analyses to measure the threshold integration of DERs, based on assumptions related to DER impacts on electric system reliability and safety. Demand response (DR) can help solve local reliability challenges in the distribution grid. ISOs have been using DR to meet peak demand and help integrate renewable energy. "Risk-aware" regulators in market states are rediscovering DR as a tool to diversify and strengthen utilities' energy resources. The grid of the future, with thousands of dispersed generators and microgrids, will be more resilient and less subject to failure. Isolating from the grid to provide service in the event of widespread outages can be a considerable benefit for customers. We must ensure that NGrid is properly incentivized to help get us to a more secure energy future.

- We need to look at existing statutory framework the way we look at our current distribution system – not in terms of how can we make what exists work but what do we need to design and improve to support the energy future we're planning for?

- Net metering has not received enough attention in the utility business model piece of this puzzle. It is one of the most powerful mechanisms upon which to transform the power sector. It is driving many of the biggest energy projects in Rhode Island right now (proposed and in development). Locational incentives are just one of many important values that could be better served through RI's net metering policy.

  At the meeting held on October 23, Tim Roughan commented that NGrid does not support remote net metering because it costs customers more than the Renewable Energy Growth Program. <u>First</u>, that comment seeks to undermine the stakeholder and consultant work in Docket 4600 (in which NGrid was a stakeholder and part of the consensus). It exposes the detrimental presumptions National Grid makes about value for customers, the distribution system and society. The simple truth is that the business as usual thinking they've been leading us through over too many years now (without adequate regulatory direction and oversight), has left us with the extraordinarily high energy costs that are (at least) one reason we need to "Transform the Power Sector." We ought to be very concerned about bias in NGrid's continued administration of electricity policies and programs and direct/implement controls and incentives that will change outlook and behavior. Implementation of Docket 4600 will help us better understand and act on real value, if the utility is not allowed to undermine it. <u>Second</u>, net metering is going to drive future benefit because it's the only program that is not administered by NGrid in a way that fundamentally constrains transformative capacity. <u>Third</u>, The REG program was based on a logical cost plus rate of return approach to ensure projects got sufficient price commitments to be financed while maximizing "cost effectiveness" – but, its engineers clearly did not fully consider the possibility that such private investments could actually return higher value for customers, the power system and society. While gradualism is important for statutory programs (to ensure stability in expectations), there has been no better stakeholder group than RI has engaged lately and if the results of that process dictate that we may need to rethink how we value and compensate DER, then we should do what we must to ensure those recommendations are acted on and the REG program is structured to drive the best value for RI. Despite NGrid's under-informed presumptions about cost and value, net metering is a critically important tool for transforming the power sector and should be molded and incentivized to drive the value we seek for customers, the grid and society.

- Please consider adding an incentive for an innovative partner model that implements thermal energy solutions on a scaled/shared basis? Arlington County, Virginia, and St. Paul, Minnesota, are both recognized as champion cities in the U.S. for their district-energy cooling and/or heating systems. A recent United Nations Environment Program (UNEP) district energy report notes that one of the most cost-effective means for reducing greenhouse gas emissions and primary energy demand is a modern district-energy system, especially one that incorporates combined heat and power (CHP, or co-generation). The analysis finds that modernizing district-energy systems can reduce heating and cooling primary-energy consumption by up to 50%. Since many systems are developed and/or operated by private-sector companies for communities, this opportunity also represents a unique public/private partnership. Co-benefits include cost savings from avoided and/or deferred investment in power- generation infrastructure, peak-load reduction, local investment and tax revenue, and local employment.
- As noted before, we still need to develop and implement a specific mechanism that neutralizes the fact that, as former utility executive Karl Rabago has said, "utilities simply do not think things they do not own or control can be resources." We cannot reasonably expect the utility to implement such change of its own volition. For example, under Solar City's proposed "Infrastructure-as-a-Service Model," after evaluating all feasible technical solutions for a particular grid need, including alternative grid solutions derived from DER portfolios, distribution system planners are empowered to select and deploy third-party assets that address the specified need if more cost-effective for ratepayers than conventional solutions. Importantly, Infrastructure-as-a-Service creates the opportunity for utilities to operate and collect streams of service income, or a rate of return, based on the successful deployment of competitively sourced third-party solutions. This service income provides fair compensation for effective administration of third-party contracts that enable alternative resources to deliver grid services, and helps mitigate the structural bias towards utility-owned infrastructure that currently exists under distribution "cost plus" regulation. Neutralizing the utility disincentive to utilizing DERs is critical but not sufficient to drive transformation in distribution planning. New incentives may be ignored in practice without corresponding changes to long-established and familiar utility processes that have sourced only self-supplied

solutions to date. The adoption of a Distribution Loading Order would borrow an existing concept from bulk system procurement policy in California, which prioritizes the utilization of flexible DER portfolios over traditional utility infrastructure, when such portfolios are cost-effective and able to meet grid needs. In concert with a mechanism like Infrastructure-as-a-Service, a Distribution Loading Order provides the procedural framework for evaluating distribution solutions in order to ensure grid planning is consistent with longer term policy objectives that support environmental, reliability, and customer choice goals. Importantly, a Distribution Loading Order would ensure that DER solutions are properly incorporated into grid planning. However, utilities would always maintain the authority to select and deploy a suitable portfolio of solutions, including conventional solutions when more appropriate, to ensure reliability. For these conventional investments, utilities would continue to earn an authorized rate of return. [see Solar City, "A Pathway to the Distributed Grid"]

Regulatory models combining a revenue cap and PIMs deserve greater consideration as jurisdictions determine how to align utility incentives with the outcomes society seeks. Under a revenue cap, a utility is rewarded when it is able to identify less costly approaches to meet grid needs. In past applications of revenue caps, cost savings took the form of more efficient implementation of conventional solutions. In contrast, a revenue cap model today would incentivize utilities to parse through the wide variety of new grid solutions that have been proposed, and implement those that benefit customers. For jurisdictions seeking to develop a more competitive market for energy services, a revenue cap also motivates utilities to procure third-party resources where they create more value under the cap. [America's Power Plan, "Moving Toward Value in Utility Compensation" p. 2]

- This sentence on page 3 has a typo in it: "This occurs because the primary financial means through which the utility can grow its business and enhance earnings for shareholders is to invest in capital projects. This bias provides an incentive [SHOULD BE A DISINCENTIVE] to seek more efficient solutions that do not depend on utility infrastructure investment."

<u>Distribution System Planning</u>

- This draft has come a very long way from the 8.15 draft and we're very grateful for its many improvements.
- The explanation of context and history of the ISR and SRP processes and evaluation of NWAs is extremely helpful.
- Combining the ISR and SRP planning processes is wise.
- Transparency and stakeholder engagement is essential, as stated. We remain concerned about the capacity of stakeholders to dedicate the resources to fully engage in any such important planning processes, of which there appear to be many. Historically, we've seen little stakeholder engagement, especially relative to the resources dedicated by the utility. The SIRI report recommends:

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.

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. It seems more and more important to have one board for oversight of all energy policy/programs with the comprehensive perspective, financial wherewithal and technical capacity to understand the big/entire picture and track all of this to ensure proper implementation. We’d propose strong consideration of merging the EERMC and DG Boards and ensuring they are equipped with the knowledge and expertise necessary to help oversee and implement state policy and track such planning processes.

- While heat and capacity mapping of the existing system are critically important (and should be accelerated), it’s important to remain focus on the long-term goals and the system we need to serve those goals (where we want to be), rather than feeling constrained by the system as it is. How does our grid need to be improved to accommodate the load and supply profile (conservation, demand response, consumption & generation) we need/want/expect to see in the future? This is the same kind of analysis that should apply to existing statutes – not, how can we make it work in the context of what’s there but what laws/policies do we need to create our designed energy future.
- The proposed improvements to the forecasting process are important and much appreciated.
- The idea that third party providers will have access to enough information to propose lower cost alternatives to customers in constrained areas is excellent and indicative of the way in which competitive markets can drive down costs if/when given easy/equal access to baseline information.
- A comprehensive approach to the implementation of locational incentives is great. This effort should be communicated to the siting stakeholder process going on right now with OER/DEM, as it’s a critically important piece of locating future DER in RI.
- The last bullet on net metering is very important. Net metering has not received enough attention in the utility business model piece of this puzzle and is one of the most powerful mechanisms upon which to transform the power sector. It is driving many of the biggest energy projects in Rhode Island right now (proposed and in development). Locational incentives are just one of many important values that could be better served through RI’s net metering policy. Hopefully, the implementation of Docket 4600 will help us better understand and act on that.

Beneficial Electrification

- The draft has not changed, so our comments haven't either. Most importantly: 1) According to our State Energy Plan, it is not possible to "Transform the Power Sector" without aggressively addressing thermal energy; 2) as addressed in the plan, all this electrification will have significant security, cost and environmental ramifications if it is not matched by doubling down on the diversification of our supply of electricity through distributed energy resources (DER); and 3) regional planning at ISO NE must properly account for local DER in their assessment of regional capacity, to ensure that we do not pay to meet our energy needs twice.