STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

Power Sector Transformation

Initial Considerations on Utility Compensation

August 15, 2017

Introduction

This document presents initial considerations on the role of the electric utility and the way that it earns compensation.

Reform to the utility compensation framework and the broader business ecosystem in which the utility operates – the utility business model – should be based on a clear vision for the future role of the electric utility. In Rhode Island, electric utilities will need to develop significant capabilities over the coming years and decades to help all Rhode Islanders manage a transition to a cleaner, less centralized, more information laden, and resilient energy system. Electric utilities will need to augment the significant capabilities they have developed over the last 100 years in designing and deploying infrastructure. The new capabilities required will include management of information, both from their distribution systems and their customers, and integration of information with infrastructure.

There are many potential commercial arrangements that may evolve in coming years to realize an information-based intelligent electrical infrastructure that enables a range of resources and engages customers and third-party service providers in new ways. Market and technology developments will need to continue to evolve to sort the commercial arrangements that will be most successful. For now, regulatory reform can address the capabilities the utilities will need to develop to engage customers and third parties. In particular, reform of the utility compensation framework should include:

First, today's utility compensation framework creates a bias for one-way, capital-intensive solutions to fix identified constraints in the distribution system. The traditional regulatory model for electric utilities, in which the electric utility earns a return based largely on the cumulative value of the prudent infrastructure it has deployed, yields a system in which a significant portion of deployed infrastructure is used for a small fraction of the year.

Second, the electric utility will, in the future, need to perform functions beyond its traditional role, in particular related to the collection and analysis of information from its own distribution system and from its customers. The electric system of the twenty-first century will depend on operation of data networks to allow the utility to gain visibility and control of the electric system. However, today's utility compensation framework does not fully encourage the utility to develop the organizational structures and capabilities needed to undertake many of the information-oriented functions that it will be called upon to perform. Many of the functions associated with operation of a data network are outside of the electric utility's traditional area of operations and include strategically important, but not capital intensive, software and service components.

Third, the electric system of the twenty-first century will be asked to deploy a range of new technology systems that pose a significant risk of technology obsolescence for the current business model in which capital expenditures are usually recovered based on a simple prudency test.

Fourth, as the Public Utilities Commission has noted in its review of the 2017 Energy Efficiency Annual Plan, development of isolated incentive mechanisms in Rhode Island may create a future risk of overlapping and unconnected performance incentive mechanisms.

To address these problems, this document proposes three reforms to the utility compensation framework in Rhode Island. These include:

- A muti-year rate plan
- A suite of performance incentive mechanisms
- A description of potential innovative partnership models for the utility

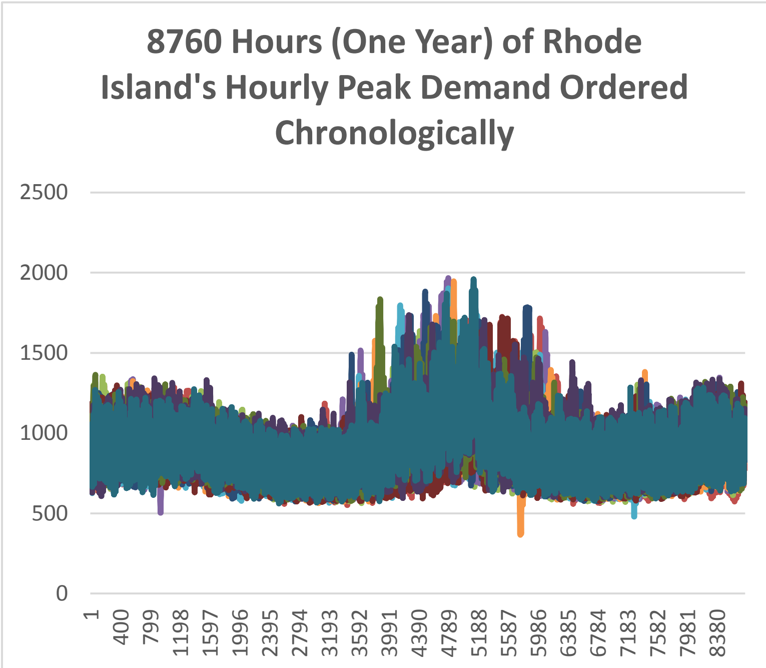
Context: The Current Utility Business Model

The current utility business model in Rhode Island is based on a compensation framework of cost-of-service ratemaking with a one-year forward test year and revenue decoupling. This framework creates several financial incentives that tend to encourage deployment of capital intensive solutions, as opposed to distributed energy resources, and may inhibit development of a long-term technology strategy. The problematic aspects of the current business model include:

1. *Rate case frequency*. The ability to submit a rate case whenever the utility chooses can erode the utility's incentive to improve performance and contain costs. Utilities have little incentive to reduce or optimize operating costs or capital costs, if they can recover all costs with frequent rate cases. DERs are one way that utilities can reduce operating and capital costs, thus frequent rate cases might diminish a utility's incentive to implement DERs.
2. *Incentive to build rate base*. Utilities have an incentive to increase their rate base, because this will lead to a higher allowed return on equity. Utilities can increase rate base by making capital investments in conventional distribution technologies. This creates a disincentive to promoting DERs, which typically do not require capital investments and can postpone or avoid capital investments that do build rate base.
3. *Reluctance to invest in innovative technologies*. Utilities are reluctant to invest in new, untried, or innovative technologies, because of risks associated with post-investment prudence reviews. This might hinder a utility's incentive to invest in certain DERs or technologies that support them, such as advanced metering infrastructure, data collection and management systems, and communication systems.

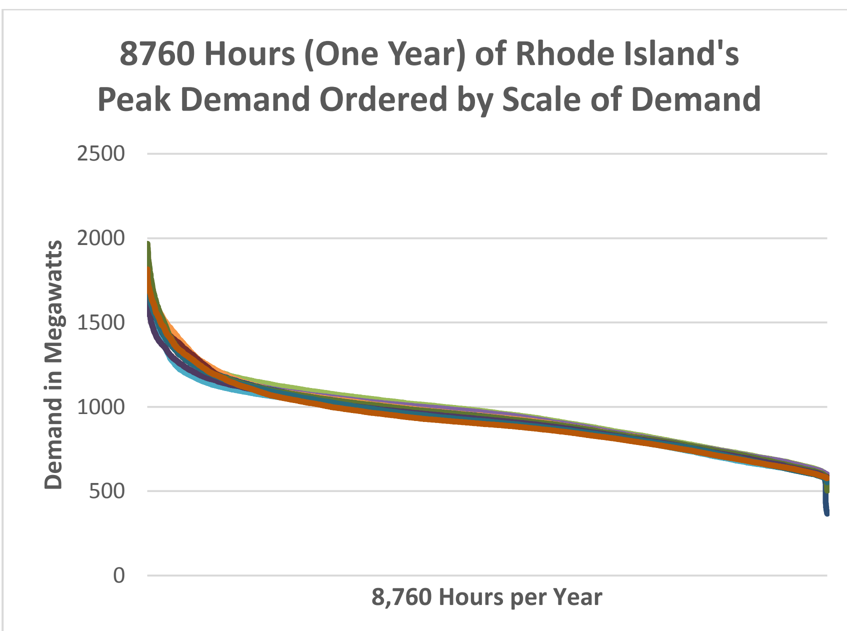
One consequence of the existing incentive paradigm is an electric grid built to meet peak demand. Chart 1 presents the peak hourly demand for the last ten years for Rhode Island displayed as a single chronological year. The chart highlights the seasonal summer peak and also the few hours which drive overall system peak for which the electrical grid must build capacity.

Chart 1



The same data appears in Chart 2 organized by the number of hours in which each peak is reached. The left side of the chart shows that a very few number of hours drive the system's capacity requirement.

Chart 2.



In recognition of the potential for distributed energy resources to provide less capital intensive grid solutions, Rhode Island has implemented a series of performance incentive mechanisms (PIMs) focused on particular performance areas. Table 1 presents the PIMs that currently apply to National Grid. Many of these incentives are defined in statute.

Table1. Existing Performance Incentive Mechanisms

Metric	Purpose	Formula	Target	Incentive
Service Quality				
SAIDI	Indicate reliability in terms of duration of outages	System average interruption duration index	yes	penalty
SAIFI	Indicate reliability in terms of frequency of outages	System average interruption frequency index	yes	penalty
Customer Satisfaction	Indicate satisfaction regarding many services	Based on customer survey	yes	penalty
Call-In Center	Indicate response time	20 second call response	yes	penalty
Renewables and Distributed Energy Resources				
Electric EE	Promote efficiency use of electric EE funds	5% of program budget, depending upon energy and capacity savings	yes	yes
Gas EE	Promote efficiency use of gas EE funds	5% of program budget, depending upon gas savings	yes	yes
SRP	Promote efficient outcome of NWA initiative	5%-9% of program budget, depending upon energy & capacity savings	yes	yes
Long-Term Contracts	Promote long-term renewable contracts	2.75% of actual payment made through PPA	no	yes
DG Standard Contracts	Promote standard contracts for renewables	2.75% of actual payment made through PPA	no	yes
RE Growth: DG Facilities	Promote DG	1.75% of the annual value of all incentives issued to DG.	yes	yes
RE Growth: SolarWise	Promote SolarWise	1.75% of the annual value of all incentives issued through SolarWise	yes	yes

Table 2 presents a preliminary analysis of the scale and scope of these existing performance incentives. The incentives, which are designed to accrue to shareholders, incent the utility to undertake activities that are beneficial for ratepayers. Although these incentives are designed as a percentage of the cost, the most comparable measure is to value the incentive as a share of the utility's return on investment. For this comparison, 100 basis points is 1% return on investment). Table 2 indicates that current incentives total roughly 44 basis points, out of a total of the over 900 basis points that represent the utility's authorized rate of return.

Table 2. Comparison of Existing Incentive Mechanisms for 2017

Program	Program Costs (2017$)	Shareholder Incentives				
		(2017$)	(% of cost)	(basis points)	(% of net income)	(% of net bens)
EE - Electricity	88,511,000	4,425,550	5.00%	24	4.5%	3.6%
EE - Gas	27,751,000	1,387,550	5.00%	8	1.4%	5.4%
SRP	400,300	20,015	5.00%	0	0.0%	-31.8%
Long-Term Contracts	72,275,022	1,987,563	2.75%	11	2.0%	---
DG Standard Contracts	7,063,354	194,242	2.75%	1	0.2%	---
RE Growth DG Facilities	1,821,337	31,873	1.75%	0	0.0%	---
RE Growth SolarWise	---	---	1.75%	---	---	---
Total	197,822,013	8,046,794	4.07%	44	8.1%	

In response to the context of the current utility business model – a cost of service regulatory framework with some additional performance incentive mechanisms, existing regulatory tools provide significant potential to reform the incentive structure of the distribution utility.

Multi-Year Rate Plans

Multi-year rate plans (MRPs) are a ratemaking construct designed to strengthen utility financial incentives to operate efficiently, make sound investments in capital and non-capital expenditures, and ultimately pass reduced costs on to customers. Two of the key elements that distinguish MRPs from traditional cost-of-service ratemaking are

(a) a rate case moratorium that prevents the utility from having frequent rate cases; and

(b) an attrition relief mechanism (ARM) that allows for utility rates (or revenues) to increase between rate cases.[1]

There are many important elements of an MRPs, and the choice of how each element is designed will have a large impact on the success and the efficacy of the MRP. The key elements to consider for the purpose of creating a straw proposal are outlined below.

- *Rate case moratorium*. How long should the rate case moratorium last? A relatively long moratorium will provide greater incentive for the utility to reduce costs and improve efficiencies. However, a relatively long moratorium creates greater risks for customers and the utility, as well as greater risks that the utility path with deviate from regulatory goals and directions

- *Attrition relief mechanism*. This is a key element of any MRP, as it will dictate the amount of revenues that a utility will be able to recover between rate cases. There are three types of ARMs:
  - Index-based, which allows for growth in revenues based on a pre-determined index. A frequently used index is inflation minus productivity (RPI-X). A simpler index is the revenue-per-customer approach, where utility revenues are allowed to increase at the same rate as the number of customers.

[1] For a very useful description and discussion of MRPs, see Lowry et. al., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Grid Modernization Laboratory Consortium, July 2017.

  - Forecast-based, which allows for growth in revenues to track a forecast of future utility expenditures. Ideally, the forecast would be based on sound distribution system planning practices, and would be informed by and supported by meaningful stakeholder input.
  - Hybrid of index- and forecast-based. Both approaches can be used for the same MRP. For example, revenues for non-capital expenditures can be adjusted with an index-based approach, while revenues for capital expenditures can be adjusted with a forecast-based approach.

- *Cost trackers*. Some costs that require different regulatory treatment can be recovered outside of the ARM. A cost tracker allows the utility to recover these costs contemporaneously on a dollar-for-dollar basis. Examples of such costs in Rhode Island include the cost of the energy efficiency programs and the renewable energy growth programs.

- *Earnings sharing mechanism*. These can be used to moderate any effects of utility over-earning or under-earning as a result of the MRP. They typically involve (a) a deadband around the allowed ROE where no sharing occurs, and (b) some profit/loss sharing between customers and the utility outside this deadband.

- *PIMs to prevent degradation of services*. PIMs are frequently applied to ensure that utility performance (e.g., reliability, customer service) does not degrade as a result of productivity pressure created by the MRP.

- *PIMs to achieve specific goals and shift utility incentives*. PIMs can also be applied to (a) identify areas of performance of interest to regulators; (b) monitor those areas of performance with metrics; (c) set clear targets for those areas of performance; and (d) provide financial incentive for those areas of performance. One example of an existing PIM is the energy efficiency shareholder incentive mechanism in place in RI.

- *Adjust allowed ROE considering potential revenues from PIMs*. In order to reduce the existing incentive to increase rate base, a utility's allowed ROE could be reduced commensurately with the utility's ability to increase revenues from PIMs, particularly PIMs to achieve specific regulatory goals.

Performance Incentive Mechanisms

Performance Incentive Mechanisms are intended to achieve two objectives: (a) to prevent the degradation of customer services, in light of the increased pressure on the utility to reduce costs; and (b) to encourage the utility to achieve specific objectives in specific performance areas.

Most PIMs in place in the US today only provide financial incentives for a small number of performance areas, and therefore have a small impact on the utility's overall financial performance. In order to have a meaningful impact on a utility's incentive to build rate base, it may be necessary to establish significant, coordinated financial incentives in both the MRP and the PIMs. If the financial rewards available from PIMs are large enough, they can replace the revenues that would otherwise be provided to the utility from its return on rate base. Reducing the allowed return on equity can therefore reduce a utility's incentive to increase its rate base. If the Company were to exceed its PIM targets, then it would see relatively higher profits, and *vice versa*.

The first step in defining broad metrics, targets and incentives is to identify and articulate regulatory policy goals. Based on stakeholder discussion in Docket 4600 following goals are relevant for Rhode Island:

- Reduce electricity costs and bills. There are several types of costs to reduce.
    - Reduce energy costs. This can be achieved by (a) reducing RI demand during ISO-NE energy market high-cost hours, (b) shifting demand from ISO-NE energy market high-cost to low-cost hours, and (c) reducing consumption in general.
    - Reduce generation capacity costs. This can be achieved by reducing RI demand during ISO-NE capacity market monthly peaks.
    - Reducing transmission capacity costs. This can be achieved by (a) reducing RI demand during ISO Transmission monthly peak hours, and (b) reducing electricity consumption in general.
    - Reduce distribution capacity costs. This can be achieved by (a) reducing peak demands on those circuits that are stressed or likely to be stressed, (b) locating DG on circuits that are not stressed or likely to be stressed, and (c) reducing electricity consumption in general.
    - Reduce the cost of compliance with environmental regulations. This can be achieved by promoting DERs, especially those that reduce energy consumption or increase clean distributed generation.
- Promote clean, distributed energy resources (DERs). This can be achieved by promoting energy efficiency resources, demand response, distributed generation, storage technologies, electric vehicles, and more.
- Promote customer engagement. This can be achieved by promoting DERs in general, but also through customer education and marketing, provision of customer data, and promotion of third-party vendors.
- Promote innovation and adoption of new technologies. This can be achieved through customer engagement, promotion of third-party vendors, provision of customer data.
- Promote power sector transformation. This can be achieved by promoting DERs, customer engagement, new technologies, and third-party engagement.

Based on the goals outlined above, Rhode Island should create new PIMs for the following performance areas:

- system efficiency
- distributed energy resources; and
- network support services

Metrics alone (without targets or financial incentives) are an effective low-cost, low-risk way to guide utility performance by indicating priority performance areas. They can also be used to monitor performance over time and indicate whether certain performance areas warrant targets and financial incentives in future versions of a performance based framework.

Tables 4-6 provide a list of the metrics that may be appropriate for Rhode Island, divided up by system performance, distributed energy resources, and network support services. Some of these metrics are based on information that National Grid already collects for other purposes. Other metrics will require the collection of new data; data that is needed anyway for distribution system planning or promoting power sector transformation.

Table 4. System Efficiency Metrics

Metric	Purpose	Formula
Transmission peak demand	Indicate the extent to which peak demand affects transmission costs	Rhode Island's monthly contribution to the ISO coincident peak
Distribution peak demand	Indicate the magnitude of distribution peak demand	Monthly peak distribution demand, by sectors
Substation peak demand	Indicate the extent to which specific substations are stressed	Percent of capacity utilized on targeted substations, during distribution monthly peaks
DG-friendly substations	Indicate the portion of substations that are capable of readily installing DG facilities	Ratio of substations that can accept DG without upgrades to all substations
Distribution load factor	Indicate the portion of distribution sales that occur in peak hours	Ratio of retail sales during peak hours to retail sales in all hours
Customer load factor	Indicate customer demand relative to energy	Ratio of distribution sales during peak hours to distribution sales in all hours, by customer sector
Time-varying rates	Indicate penetration of time-varying rates	Percent of customers on time-varying rates, by customer sector
CO_2 intensity	Indicate intensity of CO2 emissions from customers	CO_2 emissions per customer, by sector

Table 5. Distributed Energy Resource Metrics

Metric	Purpose	Formula
Energy efficiency	Indicate participation, savings, and cost effectiveness of EE programs	Percent of customers served, annual & cumulative
		Energy savings, annual and lifecycle
		Capacity savings, annual and lifecycle
		Program costs per energy saved ($/MWh)
Demand response	Indicate participation, savings, and cost effectiveness of DR programs	Percent of customers served, annual
		Capacity savings, annual and cumulative
		Program costs per capacity saved ($/kW)
Distributed generation	Indicate penetration and type of DG installations	Percent of customers with DG, annual & cum.
		DG installed capacity
		DG capacity by type (PV, CHP, small wind, etc.)
Electricity storage	Indicate penetration of storage technologies, and ability to help mitigate peaks	Percent of customers with storage, annual & cum.
		Storage installed capacity
		Percent of customers with storage technologies enrolled in demand response programs
Electric vehicles	Indicate penetration of EVs, and ability to help mitigate peaks	Percent of customers with EVs, annual & cum
		Percent customers with EVs enrolled in DR programs

Table 6. Network Support Services Metrics

Metric	Purpose	Formula
Advanced metering capabilities	Indicate penetration of advanced metering functionality	Percentage of customers with AMF, by sector
		Percentage of energy served through AMF, by sector
Interconnection support	Indicate performance of DG installation and DG study	Average days for customer interconnection
		Percent difference between study cost estimate and final cost to DG developer
Customer access to customer information	Indicate customers' ability to access their usage information	Percent of customers able to access daily usage data, by sector
		Percent of customers able to access hourly or sub-hourly usage data, by sector
Third-party access to customer information	Indicate third-parties' access to customer usage information	Percent of customers able to provide data to third-parties
		Percent of customers who have authorized third-parties to access data
Third-party access to distribution information	Indicate third-parties' access to distribution system info	Targets for providing heat maps and other relevant system data
Distribution System Planning	Indicate the ability of distribution planning to provide network support	Accuracy and accessibility of heat maps and data portal functionalities.
Customer Engagement	Indicate the relative success of the utility in creating mechanisms to connect customers with third party vendors and services.	Customer engagement survey, which measures survey scores from customers who make purchases on specific platforms that also promote third party vendors, or a transactional conversion rate that measures the frequency at which unique customer visits on specific platforms results in a purchase

Partnership Models and Capabilities for the Transition to an Information-Based Utility

There are at least four areas in which the electric utility may seek to leverage the performance incentive mechanisms described here and, in combination with existing capabilities, develop new initiatives to advance intelligent infrastructure. We outline in the broadest possible terms these areas and potential commercial arrangements to solicit stakeholder feedback and to allow market parties to innovate. Even beyond these individual areas for innovation partnership, utilities should be cognizant of how different technologies and partners connect with each other. The best partnerships will result in interoperable tools and platforms which empower each other.

1) Utilization of shared communications infrastructure:

A communications infrastructure is essential to many of the functionalities identified in the Grid Connectivity and Functionality work stream, including advanced meter infrastructure and time of use rates. To realize a shared communications network among various infrastructure providers we can envision three potential commercial arrangements:

- the use of public next generation connectivity for the electrical system in which the electric utility purchases a bulk amount of bandwidth and electricity ratepayers act as a kind of anchor tenant
- Ownership of a communications infrastructure by the electric utility with sales to other bulk infrastructure customers in which electric ratepayers fund the communications network and have costs reduced
- Participation by the utility in a special purpose vehicle with private vendors as a layer to support multiple infrastructure applications

2) Advanced Meters

National Grid has identified ownership of the meter as an important operational requirement for reliability. However, ownership and control are not barriers to allowing one or more third parties to operate the meter as a platform for data-based services. The license to operate such a platform could become a source of revenue for National Grid.

3) Electric vehicle charging stations

Electric vehicle charging stations represent an opportunity for the utility to earn revenue from a number of non-volumetric services, including:

- subscription fee services,
- installation services,
- charging station coverage maps stemming from distribution system services

4) Data Analytics

The distinction between “data” and “information” represents an important commercial opportunity for the utility and third parties to provide both public access to basic data and commercial access to information as the digested and improved product for market use. The emergent data and information portal could become a source of revenue for National Grid which could be used to offset other expenses for the benefit of ratepayers. Distributed energy resources developers would have access to some data without charge and might subscribe to have access to other information if they chose to find it of value.

<u>Questions for Discussion and Additional Stakeholder Comment</u>

1) Please provide any recommendations related to the components of the multiyear rate plan described on page 6 of this document.

2) Please provide any recommendation regarding the metrics outlined in Tables 4, 5 and 6 to ensure they are comprehensive and specific. In particular, please provide any recommendations related to development of the metric formulas.

3) If there is an area that would benefit from a metric not included here please provide any recommendations for it.

4) Among the three broad groups of metrics, System Efficiency, Distributed Energy Resources and Network Support Services, please provide recommendation of how much weight should be allocated to each broad category, perhaps in terms of percentage of a total performance incentive allocation budget.

5) Please provide any recommendations for how you think the metrics should be structured, or nested, within the broad categories.

6) Please provide any recommendations related to any of the Innovation Partner Models described on page 11 of this document.

Comments may be submitted at any time, however we request that we receive comments by email Friday by September 8th. All comments will be made public.