September 8, 2017

Macky McCleary
Administrator
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

Carol J. Grant
Commissioner
Office of Energy Resources
One Capitol Hill
Providence, RI 02908

Re: Initial Considerations on Utility Compensation; Advanced Grid Capabilities and Questions for Stakeholders

Dear Administrator McCleary and Commissioner Grant:

Enclosed, please find comments from the Northeast Clean Energy Council (NECEC) and Advanced Energy Economy Institute (AEE Institute) in response to your agencies' August 15 Initial Considerations on Utility Compensation and the August 20 Advanced Grid Capabilities and Questions for Stakeholders.

Our organizations are available as a resource to you as efforts within the Power Sector Transformation Initiative continue to develop and progress. Please let us know if we can be of any assistance.

Sincerely,

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NECEC

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Initial Considerations on Utility Compensation; Advanced Grid Capabilities and Questions for Stakeholders

Introduction

The Northeast Clean Energy Council (NECEC) and Advanced Energy Economy Institute (AEE Institute) commend the Rhode Island Division of Public Utilities and Carriers (DPUC), the Office of Energy Resources (OER), and the Public Utilities Commission (PUC or Commission) for their work within the Power Sector Transformation Initiative. We greatly appreciate the opportunity to respond to the *Initial Considerations on Utility Compensation* and the *Advanced Grid Capabilities and Questions for Stakeholders* issued and to participate in support of your agencies' ongoing efforts.

NECEC is a clean energy business, policy and innovation organization. Our mission is to create a world-class clean energy hub in the Northeast delivering global impact with economic, energy and environmental solutions. NECEC is the only organization in the Northeast that covers all of the clean energy market segments, representing the business perspectives of investors and clean energy companies across every stage of development. Our members span the broad spectrum of the clean energy industry, including energy efficiency, demand response, wind, solar, combined heat and power, energy storage, fuel cells, and advanced and "smart" technologies. Many of our members are doing business and investing in Rhode Island, and many more are interested in doing so in the future.

AEE Institute is a charitable and educational organization whose mission is to raise awareness of the public benefits and opportunities of advanced energy. AEE Institute is affiliated with Advanced Energy Economy (AEE), a national business association representing leaders in the advanced energy industry. AEE supports a broad portfolio of technologies, products and services that enhances U.S. competiveness and economic growth through an efficient, high-performing energy system that is clean, secure and affordable.

NECEC and AEE Institute submit these comments on the proposals for distribution system planning improvements in Rhode Island in response to the August 15 Notice. In these comments, NECEC and AEE Institute will be referenced collectively as "the advanced energy community," "we," and "our."

NECEC and AEE Institute have substantial experience participating in grid modernization proceedings across the country. As organizations with stakeholders that provide a range of technologies and services, we balance a wide variety of interests and address issues with a technology-neutral perspective. Every state has different goals, legal requirements, and market conditions, and so therefore takes a different approach to grid modernization and potential distribution system planning reforms. In these comments, we have based our responses to the questions posed in the August 15 and August 20 Notices on NECEC's extensive experience in regulatory, policymaking, and legislative processes in Rhode Island, as well as the experience of both of our organizations in other states, while keeping in mind the unique characteristics of Rhode Island.

Initial Proposals on Utility Compensation

In your August 15 notice, three overarching areas were highlighted for discussion related to improved mechanisms for utility compensation. Changing how utilities are compensated and recover their costs to serve customers is critical to helping transition Rhode Island to the "cleaner, less centralized, more information laden, and resilient energy system" of the twenty first century.[1] These changes will affect or influence both utility distribution and business planning: that is, how utilities plan the distribution system and the role that they play within the larger electricity and energy ecosystem.

The agencies identified three areas for comment:

1. Consideration of a new ratemaking construct involving **Multi-Year Rate Plans (MRPs)** designed to strengthen utility incentives to operate efficiently and make sound investments.
2. Evaluation of potential **Performance Incentive Mechanisms (PIMs)** that would both minimize the potential for reduced levels of service to customers within the context of increased budgetary pressures while encouraging achievement of specific desired objectives.
3. Review of **Potential Partnership Models and Capabilities for the Transition to an Information-Based Utility**

In the following sections, NECEC and AEEI address the specific questions posed by agencies in each of these three areas.

MULTI-YEAR RATE PLANS

The utility world has evolved in recent years, presenting new challenges and opportunities, for which the current ratemaking construct is no longer well suited. The current practice of providing cost recovery through frequent rate cases no longer serves the utility or its customers well, diminishing incentives to adopt a longer-term, more efficient, and holistic system view, among other things. Furthermore, the existing cost-of-service, rate-based approach leads to a supply-side infrastructure-oriented bias, rather than an integrated supply-demand "transactive energy" approach that will be more economically efficient for society. Finally, the current approach to utility compensation discourages innovation, both at the technology and business model level.

NECEC and AEEI see the value in designing a longer-term, multi-year rate plan (MRP) approach that encourages and compensates the utility to take a broader view as to how to provide delivery of cost-effective electricity service to Rhode Island's citizens. This will necessarily involve addressing the inefficiencies of sizing infrastructure for peak demand, and focusing on a goal of achieving improved capital efficiency. The agencies identify two key elements that distinguish MRPs from traditional ratemaking: a rate case moratorium that prevents utilities from having frequent rate case proceedings, and an attrition relief mechanism (ARM) that allow rates or revenues to increase between rate cases. In addition, the agencies raised seven potential elements and considerations included in an MRP, each of which will be addressed below:

[1] RIPUC Power Transformation: Initial Considerations on Utility Compensation, August 15, 2017.

***MRP terms (bearing in mind that longer periods strengthen incentives to improve efficiencies but also entail greater risk as there is less room for mid-course corrections)*:**

We believe that a three-year MRP is a reasonable length of time at this moment, for several reasons. First, three years appropriately balances incentives and risks as Rhode Island transitions from the current ratemaking framework to a new one. It is long enough to enable the utility to adjust planning and expenditures in response to incentives but not so long that it puts the utility or customers at risk. Second, technology and business models are evolving rapidly such that a longer period might not allow for adjustments in response to changing circumstances and costs. For example, lithium ion battery costs have fallen by almost 50% just since 2014,[2] while solar costs are expected to continue declining by four to five percent annually in coming years.[3] A longer timeframe could result in a delay in taking these changes into account, whereas annual rate plans provide a disincentive to adopt a broader and longer-term framework, the objective of Rhode Island's Power Sector Transformation Initiative.

It will be important to evaluate each successive MRP within the context of an articulated long-term strategy to develop the utility of the 21st Century, so that while these technologies and business models will continue to evolve, the utility can be expected to apply a consistent decision-making framework and consistent goals.

***Attrition relief mechanism (ARM)*:**

Agencies outline three potential approaches to ARMs, which set the amounts that National Grid would be able to recover between rate cases:

1) Index-based – fixed to a pre-set index (such as inflation minus productivity, or revenue per customer account);
2) Forecast-based – tied to forecasted future expenditures, informed by stakeholder input;
3) A hybrid of both (index for non-capital and forecast for capital expenditures)

NECEC and AEEI suggest that Rhode Island consider building on current regulatory mechanisms that include forecasts and decoupling, and seek additional stakeholder input on how they might be refined. At this point in time, moving to an index may not provide the transparency regarding drivers of costs and revenues that would be desirable. Over time, some kind of hybrid approach may be appropriate.

Cost trackers:

In the August 15 document, the agencies observe that costs for some programs – such as energy efficiency and Renewable Energy Growth programs – entail a different regulatory treatment, and can be recovered through cost trackers.

While the utilization of cost trackers allows the utility to recover these costs contemporaneously on a dollar-for-dollar basis, they do not get at the ultimate goal for which these dollars are being expended: namely, the promotion of energy efficiency, addition of more renewable resources, or overall capital efficiency. While we believe it is important to compensate the utilities for prudently

[2] https://thinkprogress.org/chart-of-the-month-driven-by-tesla-battery-prices-cut-in-half-since-2014-718752a30a42/
[3] https://www.greentechmedia.com/articles/read/solar-costs-are-hitting-jaw-dropping-lows-in-every-region-of-the-world

incurred expenditures, at least in the short run while the MRP is in the process of development and refinement, ultimately the compensatory mechanism (potentially in the form of specific true-up PIMs during the MRP) should focus on the *efficacy and actual results* achieved through these expenditures.

To determine the appropriate levels of compensation in the longer-run, it is critical for the agencies to work with stakeholders and National Grid to ensure that incentives (in this case, to ensure continued investment in energy efficiency and renewable energy) are set at the right levels to achieve the desired outcomes. For the near-term, NECEC and AEEI believe that an appropriate approach to cost trackers for cost recovery of expenses for efficiency and Renewable Energy Growth programs could continue to involve repayment of expenditures and current incentive levels. A transition to an incentive to be collected based upon the actual performance relative to specific PIMs prescribed in advance could be developed by the end of the first MRP (i.e., in three years). (See below for discussion of collection of information on metrics and development of PIMs based on these metrics.)

***Earnings sharing mechanism*:**

Earnings sharing mechanisms (ESM) can moderate the effects of utility over- or under-earning resulting from the use of a MRP. Such an approach often involves a specified deadband around the return on equity where no action is taken, and a profit or loss-sharing arrangement between utility and customers if beyond the specified band. NECEC and AEEI suggest that a reasonable deadband (e.g., plus or minus 150 basis points around the allowed ROE) would be appropriate to address the potential to over- or under-earn during the period of the initial MRP. We recommend adopting an approach so that customers are rewarded with a larger share of the upside over the deadband, and have to pay less for any downside. Again, we recommend an approach involving multiple stakeholders and National Grid to establish appropriate incentive levels.

***Performance Incentive Mechanisms (PIMs) to prevent degradation of services*:**

PIMs are essential to ensure that certain performance metrics (e.g., customer service and reliability) do not degrade as a result of productivity pressure created by the MRP. NECEC and AEEI agree that the metrics articulated in Table 1 regarding **Service Quality** are reasonable and recommend that these stay the same on a going forward basis. With regard to **Renewables and Distributed Resources**, it is appropriate to evaluate the metrics listed with respect to the overall value and benefits created for the system and customers. An efficiency measure may have dramatically different values to the system depending on what it is, when it consumes energy, and where it is located on the network.[4] The absolute values (in terms of revenues for the utility) for electric energy efficiency and System Reliability Procurement (SRP) (with the explicit goal of promoting efficient outcomes of NWA) should be re-evaluated to remove any disincentives to consider NWAs compared with traditional utility investments as a result of the revenues that can be earned by each.

Given the existence of numerous cost-effective technologies, and the declining costs of many others, we believe the key focus should not be on the absolute percentage amount of the

[4] For example, while both are beneficial, a given capacity value of LED office lighting retrofits in an office may have a greater system value than an equivalent amount of LED street lighting. Concerning value, the most frequently cited example is Consolidated Edison's Brooklyn Queens Demand Management project, where $200 million of planned investments in NWAs will forestall the need to invest in estimated $1.2 billion in a new substation, feeders, and switching stations.

expenditures, but on the long-term value to the system and customers, i.e., do they lead to overall capital efficiency for the utility and savings for the customer. Likewise, the promotion of long-term renewable contracts, distributed generation assets, and SolarWise should be based upon their context (in particular, location on the grid) and the value provided to the system.

Stipulated minimum percentages have been helpful in kick-starting nascent industries and a network of vendors. The existence of an existing vendor ecosystem, coupled with the articulated goal of building a grid of the future, suggests that a more sophisticated approach to goals-setting should be developed for the (near) future, linking the PIMs in Table 1 with the DER metrics, purposes and formulas laid out in Tables 4 and 5.

***PIMs to achieve specific goals and shift utility incentives*:**

PIMs should be established to identify and set discernible targets, develop performance metrics, monitor activity in areas of specific policy interest to regulators (such as the energy efficiency shareholder incentive mechanism extant in Rhode Island), and lead to financial consequences for the utility. One of the most important roles of the utility going forward will be the ability to integrate all technology regardless of ownership. Utilities therefore should receive incentives to manage all assets well. This includes planning, asset management, and operations. The utility, for example, must be as good at integrating DER owned by a customer or a third party as it is with its own assets.

***Adjust allowed ROE considering potential revenues from PIMs*:**

As PIMs are implemented to ensure high levels of service to customers and achieve specific goals and regulatory objectives, the agencies suggest that the allowed ROE can be adjusted commensurately.

Agencies observes that the value of the existing PIMs for 2017 are equivalent to roughly 44 basis points, out of a total of over 900 basis points constituting the utility's authorized rate of return.[5] NECEC and AEEI support the goal of the Power Sector Transformation Initiative to achieve a more efficient and reliable network that engages third parties and actively fosters the adoption and utilization of superior technologies and business models that is in the best interest of Rhode Island. It also specifically involves achieving or surpassing the metrics and purposes identified in Tables 4 and 5 as elements to be incorporated into PIMs. Therefore, the revenue from PIMs should represent a significantly larger percentage of the utility's overall compensation over time. This amount could be increased to roughly 200 to 300 basis points, subject to a total earnings cap. The process of setting this compensation should involve an open and inclusive process when determining targets and shifting incentive levels to ensure that targets are objective, reasonable and fair. However, we also believe that if there is an earnings upside, there should also be some symmetry with respect to the downside. If targets are not achieved, there should be a reduction in compensation.

PERFORMANCE INCENTIVE MECHANISMS

PIMs are established to prevent degradation of service as the utility faces budgetary pressure, and encourage the utility to achieve certain objectives. PIMs shift the focus of the utility from static cost minimization to enhancement of value as utilities are given incentives to improve

[5] NECEC and AEEI note that while PIMs may be valued in terms of their effect on ROE, they should not be structured as adders to ROE, as this will lead to increased incentives for utility capital investment.

performance, which leads to an increased return on investment. PIMs also greatly enhance transparency and accountability on the part of the utility, which directly addresses regulatory concerns regarding the prudency and value of capital investment and non-capital expenditures. The challenge in setting PIMs is to make them significant enough to influence behavior and to properly and effectively calibrate their value or the revenue they generate with value of return on equity from the utility's ratebase.

The specific goals to be achieved (based on Docket 4600) are:

- Cost reductions in energy, capacity, transmission, and distribution, as well as compliance with environmental regulations. These goals can generally be achieved by reducing consumption during high-cost hours, shifting costs from high-cost to low-cost hours, and minimizing overall consumption. Adoption of clean distributed energy resources (DERs) can also help.
- Promotion of clean DERs such as solar and storage.
- Promotion of customer engagement
- Promotion of innovation and new technology adoption
- Promotion of power sector transformation by doing the above with the help of third parties

To that end, NECEC and AEEI agree with the agencies proposal to develop new PIMs for:

- System efficiency
- DERs
- Network support services

The potential metrics below are suggested as a place to start. We note that metrics are not the same as PIMs but rather data and information that are needed to develop PIMs. The metrics listed are numerous and overlap in terms of what they are designed to measure. Tying compensation directly to each of these metrics would be inappropriate. Rather, these metrics help measure utility activities and progress along the way towards an end goal – specifically aimed at reduction of peak demand and achieving overall system efficiencies. Those are the specific goals on which incentives for performance should be based.

Some, but not all, of these metrics can be incorporated into specific PIMs upon which compensation is based. We suggest collecting the suggested data in the tables for at least a year and then revisiting them to develop appropriate incentives with financial consequences. To the extent this information is available, we suggest going back another two to three years to establish a baseline for performance.

NECEC and AEEI further note that the metrics are also intended to provide important signals to third parties as to where best to target their activities and investments, so that they are offering the solutions that also help to meet the overarching objectives. NECEC and AEEI discussed the importance of customer and system data and information access in our September 1, 2017 comments on Distribution Planning.

Table 4. System Efficiency Metrics

Metric	Purpose	Formula
Transmission peak demand	Indicate the extent to which peak demand affects	Rhode Island's monthly contribution to the ISO

	transmission costs	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 distribution sales during peak hours to distribution sales in all hours, by customer sector
Customer load factor	Indicate customer demand relative to energy	Ratio of retail sales during peak hours to retail sales in all hours
Time-varying rates	Indicate penetration of time-varying rates	Percent of customers on time-varying rates, by customer sector
CO2 intensity	Indicate intensity of CO2 emissions from customers	CO2 emissions per customer, by sector

It should also be noted that customer and distribution load factors are simply one way of measuring changes occurring on the grid. The long-term goal should not be to increase load factors, but rather to reduce system peaks.

***System efficiency metrics provided in Table 4*:**

NECEC and AEEI are in general agreement that the metrics related to system efficiencies will be useful, particularly as information to third parties and customers to help them devise solutions to problems on the system, as the goal is to track trends related to overall efficiencies as well as identify and track specific opportunities for improvements at the infrastructural level. However, we have the following specific comments on the proposed metrics:

Distribution peak demand: It would be helpful to clarify whether the ‘sectors’ mentioned here refer to residential, commercial, and industrial or by geography.

Substation peak demand: The capacity utilization numbers for targeted substations are useful, as would be the location of all targeted substations. For those at peak capacity, replacement costs and estimated replacement dates would be useful.

DG-friendly substations: The language is confusing in this metric. Perhaps “Ratio of substations that can accept DG without upgrades relative to total number of substations.” That metric by itself does not provide much value, since it does not highlight where the opportunities and constraints exist on the system. It will be critical to know the locations of those substations, with the available capacity at peak demand on each, in order to determine how much DG can be added to the system without upgrades.

Distribution load factor: Most helpful would be the aggregated load curve (or at a minimum monthly distribution load factors) for each of the monthly peaks. This is not a metric itself, but a very useful tool for evaluating efficiencies in the distribution system.

Customer load factor: This metric is useful by customer sector, especially if also provided on a monthly basis, but the provision of monthly aggregated load curves would add value.

Time varying rates: This should also include not just percent of absolute number of customers, but also percent of overall energy load as well as by capacity. Those numbers will help to target sectors and achieve the actual goals to be achieved: reduction of on-peak load as well as capacity affecting system peak, as well as reduced requirements for transmission and distribution assets. Ultimately, metrics should focus on goals achieved. For example, if Critical Peak Pricing is part of the TVR approach, there should be a PIM associated with peak reduction during Critical Peak Pricing events.

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 & cumulative
		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 & cumulative
		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 & cumulative
		Percent customers with EVs enrolled in DR programs

***DER Metrics provided in Table 5*:**

NECEC and AEEI make the following recommendations regarding DER metrics:

Energy efficiency: The formula should also include a program cost per capacity ($/MW). Likewise, information should be provided by customer sector (residential, commercial, and industrial). And metrics should tie to long-term benefits.

Demand response: The formula should be broken down by sector (residential, commercial, and industrial) as well as program costs per participant.

Distributed generation**:** The formula should be broken down by sector (residential, commercial, and industrial).

Storage**:** the formula should be broken down by sector (residential, commercial, and industrial).

Electric vehicles**:** New technologies and business models may facilitate widespread EV DR programs within the foreseeable future, and there are some interesting trial projects and studies working to further evaluate this potential.[6] We believe therefore that the metric should remain in place to gather important information as the current objective is to track changes and progress. Financial consequences can be determined at a later date.

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

[6] DR has been developed in a Pacific Gas & Electric BMW 100 kW pilot by delaying charging that otherwise would have occurred, coupled with second life batteries. On average only 20 kW of capacity came from delayed charging, with remainder from the batteries. http://www.pgecurrents.com/2017/06/08/pge-bmw-pilot-successfully-demonstrates-electric-vehicles-as-an-effective-grid-resource/. Nissan and Italian energy company Enel have recently launched a program in the UK to install 100 vehicle to grid units that permit EV owners to sell electricity back to the grid.

		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
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

Network Support Services metrics provided in Table 6:

In general, taking into account the fact that these investments may be substantial, metrics that help to set priorities in terms of sequencing of activities and investments will be helpful.[7] The following suggestions are made with this context in mind.

Advanced metering capabilities: As noted in Hawaii Electric's newly released Grid Modernization Plan, advanced meter functionality has progressed rapidly in just the past several years, so that new meters now have the ability to include 'integrated grid sensing, computing, and open standards communications…The result is better information for customers to control energy bills and select services, improved reliability and service quality, and greater access for DER adoption."[8] It will therefore be critical to ensure that the investments made in advanced meter infrastructure are capable of hosting future applications and a broad level of capabilities. In short, they must be 'future-proofed' to the extent possible.

[7] For example, in Hawaii Electric Company's newly submitted Grid Modernization Plan (August 29, 2017), the utility deliberately sets out a plan to prioritize implementation based on value: "With so much new technology arriving, the idea is to focus on near-term improvements that provide the most immediate system and customer benefit but don't crowd out future breakthroughs." https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf.

[8] https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/final_august_2017_grid_modernization_strategy.pdf. The utility notes that internal computing platforms now enable multiple applications that can be downloaded, with possibilities for applications to provide interaction between the advanced meter and intelligent switches, "with the advanced meter providing actionable data to the intelligent switch to coordinate feeder switching with changing loads after an outage." HECo notes that new meters are interoperable with all telecommunications platforms, and also expects peer-to-peer networks to be available shortly as well.

Percentage of capacity served should be an additional metric. It would also be helpful to know where the Advanced Metering Functionality (AMF) is on the distribution system. It will be important to prioritize deployment by economic value, so that the information provided includes not just the volume of energy served, but location on the utility heat map.

We are supportive of full scale advanced metering deployment if the broad long-term benefits exceed costs. This should be considered and determined as part of the initiative to transform the power grid.

Interconnection support: Metrics should also be tied to location and National Grid's heat and hosting capacity maps, so that a better picture of constraints to the entire system can be derived.

Customer access to customer information: Additional metrics should include: percentage of customers able to access real-time (or near real-time data). The suggested metrics (and this one) should be broken down further not just by sector, but by total % of load and capacity in each sector that have these capabilities (e.g., % of total MWh load, and % of capacity in the industrial sector, commercial sector, and residential sectors, that has access to usage data), provided in formats of hourly, fifteen minute, five minute, with a detailed level of latency – delay in provision between when the information was generated at the meter and provided to the customer.

Third party access to customer information: Additional metrics should include: percentage of customers able to provide real-time (or near real-time data) to third parties and percent of customers who have authorized third parties to access real-time data. These metrics should be broken down further not just by sector, but by total % of load and capacity in each sector that have these capabilities (e.g. 50% of total MWh load in the industrial sector has provided third parties with access to usage data), provided in formats of hourly, fifteen minute, five minute, with a detailed level of latency. The same level of information should be provided for those customers who have actually authorized provision of this information, since the number of customers served will not affect system efficiencies as greatly as the actual impact on energy consumption and capacity requirements. The goal need not be 100% access right away, though there may be increasing value and opportunities for new products and services the more information is available.

Third party access to distribution information**:** Suggested metrics should track accuracy and frequency of updates to heat maps and hosting capacity documentation.

Distribution system planning**:** These distribution planning metrics should track what customers and third parties are doing with the distribution system information (e.g. forecasts of distributed DG penetration). (Please also see the comments on data access in the Distribution Planning comments filed by NECEC and AEEI on September 1, 2017, and June 19, 2017.)

Customer engagement**:** Additional metrics should include costs per kWh and kW for the services and programs offered by specific vendors or through specific platforms, in order to fine tune targeting of future expenditures.

***Weight to be accorded to the groups of metrics in Tables 4-6*:**

NECEC and AEEI reiterate that the metrics in Tables 4-6 should be used to inform the development of PIMs as there are many of them and they overlap. Since the overall objective is to enable a more efficient modern grid, the critical elements to be tracked here are transactional metrics related to specific actions taken by customers and third parties.

Broadly speaking, Table 4 provides the macro metrics at the strategic level, e.g., costs, overall ratios, etc., that provide the indicators of both cost and efficiency. These strategic macro indicators are critical in that they provide an indication as to how well the overall strategy is succeeding. As such, it does not involve much by way of specific investments. Therefore, it does not appear to require a weighting, *per se*, as the elements of Tables 5 and 6 may.

Tables 5 and 6 provide information at the tactical level, i.e., the 'how" the larger goals are achieved, with 5 being oriented more towards specific technologies as well as energy and capacity reducing technologies. Metrics in Table 5 help indicate what is working and what is most cost-effective. Table 6 has to do with more programmatic and information-related approaches that facilitate implementation of technologies and programs outlined in Table 4. At the highest broad category levels, it is most critical to set the stage with the tools outlined in Table 6. If they are built correctly and avoided costs and economic value clearly shown, investments will follow.

The weighting towards information and platform support also strives to take into account the inevitability of technology obsolescence. For example, as discussed in NECEC's and AEEI's initial comments on utility business models, approaches that engage third parties and cloud-based software-as-a-service (SaaS) information distribution platforms, which can often be upgraded using the existing architecture, should be considered – basing solutions in the cloud, rather than on-premise, helps to mitigate against platform obsolescence. Equipment cannot similarly be upgraded and is thus more vulnerable to becoming updated in an environment characterized by rapid technological evolution combined with international competition and rapidly declining costs.

PARTNERSHIP MODELS AND CAPABILITIES FOR THE TRANSITION TO AN INFORMATION-BASED UTILITY

PIMs can encourage and reward the utility to advance intelligent infrastructure and facilitate innovation by market parties (and penalize them for not doing so). A specific goal here is for the utility to take advantage of markets to innovate and create beneficial partnerships. In this area, the agencies identify a number of specific technologies and approaches to be considered. NECEC and AEEI address these approaches in the comments related to communications infrastructure, advanced meters, electric vehicles and data analytics below.

1) Utilization of shared communications infrastructure: The grid of the future is largely dependent upon efficient and effective flow of information. At a minimum, three potential approaches to the communications infrastructure could be adopted:
    - The use of public next generation connectivity for the electrical system in which the electric utility purchases a bulk amount of bandwidth and 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

Broadly, decisions regarding which approach to take to deploying communications infrastructure should be guided by the objective of advancing power sector transformation in a manner that reduces costs and risks for customers and the utility. Capturing ancillary benefits (e.g., for the communications system) should also be taken into account.

2) Advanced meters: National Grid sees ownership of the meter as critical for maintaining reliability. However, third parties could operate the meter as a platform for data-based services, with licensing as a source of revenue to the utility. Irrespective of the ownership issue (which merits further in-depth discussion), as a growing number of distributed assets get integrated into the system, it becomes even more critical for National Grid to invest in analytics and software solutions that help them manage the distributed system.

NECEC and AEEI are agnostic about meter ownership as long as the data and information collected by advanced metering is made available to customers and third parties. As discussed earlier, we note that there may be attendant risk in owning the meter, particularly as the technology is advancing so rapidly that there is a non-zero risk of technological obsolescence. As noted previously above Hawaiian Electric Company's Grid Modernization plan specifically comments on the rapidly changing nature of advanced metering.[9] Outsourcing these services to a third party may be beneficial, since the technological risk then falls on independent investors, rather than potentially becoming a risk to ratepayers. Should the utility remain in the role of owner, to mitigate this risk, there should be a comprehensive review of benefits and costs, appropriate metrics to be tracked regarding AMF deployment, and incentives for the utility to meet these metrics (similar to PIMs suggested here) that include both grid and customer side benefits. Regulatory oversight of deployment and capabilities of AMF will be essential with utility ownership of metering.

3) Electric vehicle charging stations: EV charging stations could represent a revenue-earning opportunity for the utility for services including:
   - Subscription services
   - Installation services
   - Charging station coverage maps stemming from distribution services

As noted in our organizations' prior comments on Beneficial Electrification, both utilities and third parties have important roles to play in the development of electric vehicle charging infrastructure up to and including ownership under appropriate rules. Studies have shown that the lack of charging infrastructure under the current market paradigm is a significant deterrent to the expansion of EV deployment and all the well documented associated benefits for ratepayers, citizens more broadly, and the state as it pursues its policy objectives. Given the situation, investments (in a variety of forms) are needed in charging infrastructure from both utilities and private sector entities, and there is extensive opportunity for partnership between the two.

As a baseline level of partnership, since the utilities need to carefully plan for any major changes in the grid, both in terms of generation and distribution, regulators and any EVSE providers should work closely with the utility on deployment to maximize the benefits that PEVs

9 https://www.hawaiianelectric.com/Documents/about_us/investing_in_the_future/grid_modernization_strategy_draft.pdf

provide to the grid, and to ensure successful integration of the additional loads from PEV charging. This might include, but is not limited to, identifying preferred sites for EVSE to be located.

In the short-term, the utility may play a useful role by owning charging stations and related infrastructure in strategic locations that help to catalyze the industry. The utility role[10] should be targeted to the barriers that impede the development of a robust market, both generally and with respect to specific underserved segments of the market, and such involvement should end once a competitive market exists. Longer-term as the market evolves, we would expect third parties to begin making significant investments in charging infrastructure as the number of EVs increase and the industry matures. We note that there are multiple private sector entities that are developing experience in financing and building out these networks, and they are already providing EV charging stations. New business models continue to emerge and should be encouraged. Care should be taken to ensure that utility ownership at early stages does not create a barrier to the growth of independent charging companies. We further suggest that National Grid consider partnering with an existing actor or actors in this space.

4) Data analytics: there are opportunities for National Grid to earn revenue through an emergent data and information portal, whereby the utility and third parties provide access to usage data and information. An information portal could become a source of revenue to National Grid, which could be used to offset other expenses. Third party vendors could subscribe to information of value.

NECEC and AEEI discussed the concept of the portal at length in our prior comments (submitted September 1, 2017) concerning Distribution System Planning.

Advanced Grid Capabilities and Questions for Stakeholders

In your agencies' August 20 Inquiry, you invite stakeholders to respond to the following six questions.

1) **Utility proposals for advanced meter functionality and distribution automation should seek to achieve a defined list of capabilities. Please review the accompanying list of capabilities and provide any comment on the completeness of the chart, the accuracy of the definitions, and the relative importance of each goal and capability within each goal.**

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[10] In California, the utility commission recently ruled that the state's three major investor-owned utilities should be permitted to own electric vehicle supply equipment (EVSEs) on a case-by-case basis and directed them to submit plans for deploying EVSEs to accelerate the development of the EV market. In 2016, the three large IOUs received approval for direct ownership of EVSEs totaling $197 million in investment. Two of the proposals include direct ownership of EVSEs by utilities, while one calls for private ownership to be facilitated with utility incentives (in this case the utility will own all infrastructure except for the EV charging units themselves). In January 2017, all three large IOUs filed plans focused on medium and heavy-duty vehicles, calling for a total of $1.07 billion in investment. These rulings serve as examples of where market conditions support utility DER ownership where they address market failures (especially the fact that third-party EVSE ownership is generally not a viable model yet due in part to low numbers of EVs on the road) and meet a public interest objective to support the state's existing policy goal of deploying 1.5 million EVs by 2025.

NECEC's and AEEI's initial impression is that the chart is a good start though we note that we and our members did not have sufficient time for detailed review. We look forward to working with others to refine it.

2) **Advanced meter functionality can enable a wide range of system and customer benefits. Please provide any information you may have to help us evaluate the qualitative system and customer benefits from each capability.**

As we noted in our comments concerning the Distribution System Planning Improvements, a key function of advanced metering functionality is the ability to stream information from the customer site in real time. This consumption data, when paired with both tariffs and wholesale market opportunities, provides critical information that will help to unlock customers' price-responsive elasticities. It enables not only the ability to provide signals for and measure demand response, but also creates heretofore non-existent price responsive capabilities. This in turn should lead to a more efficient system as a whole.

Customer benefits are often what make AMF deployment cost effective. Baltimore Gas & Electric's peak time rebate (PTR) program, *Smart Energy Rewards*, made up 50% of the total benefits presented in its AMI business case, equivalent to $1.25 billion over the 15-year expected life of the AMI components. In total, customer benefits accounted for 70% of the total benefits.[11] Any AMF business case must include a commitment to achieving well-defined and quantifiable customer benefits, along with a detailed strategy for how customer benefits are to be achieved.

3) **Advanced meters, like any technology, carry risks of becoming obsolete. Please describe ownership and operating models for advanced meters that address the risk of obsolescence.**

As noted above in the Partnership Models and Capabilities section of this response and our earlier comments in this process, third party ownership of meters and/or communications infrastructure is one way to mitigate against technology obsolescence, if the owners are responsible for delivering specific outcomes at an agreed-upon price. Although it clearly must have access to pertinent information supplied by these devices, the utility does not necessarily need to own the meter. The information could be acquired from a third party through a SaaS model.

4) **Please describe any complementary measures necessary to ensure that the benefits of advanced meter applications are accessible to all customer classes, especially income eligible.**

A customer class may well benefit from the deployment of advanced meters even when one's own rate class is not affected by the deployment provided that: a) the meters deployed lead to increased overall system efficiencies, and that b) some of those efficiency benefits positively affect that given rate class. For example, over the first few years of Baltimore Gas and Electric's (BGE's) peak time rebate program, enabled by advanced metering, non-BGE customers in adjacent zones saved an additional $126 million due to the program, illustrating how benefits extend to the system at large, including non-participants. It may, in fact, not be cost-effective to deploy advanced metering infrastructure to income eligible rate classes, since – in many cases -

[11] Baltimore Gas & Electric Company, 2011, "Application for Authorization to Deploy Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Costs", Case Number 9208.

they neither consume much electricity in the context of the entire system nor are they likely to have the ability to respond to such mechanisms as time-of-use rates.[12]

In order to achieve the full grid-side benefits, AMI investment needs to also include investment in advanced distribution system management and software-based analytical capabilities that ensure the utility has the ability to manage the data from those meters and achieve overall system efficiencies that reduce costs across all customers. In order to achieve the full customer benefits of AMI, investment needs to include significant, personalized customer engagement before, during, and after AMI installations. This will increase awareness, adoption, and acceptance of AMI meters across different customer classes. Customer engagement should include an online data portal as discussed in question 5 (and earlier comments) as well as proactive messaging and outreach from the utility to customers to demonstrate the benefits of AMI and provide the tools necessary for customers to utilize AMI data to better manage their energy use.

5) **Advanced meters offer a platform on which the utility, or a third party, can provide software services, such as demand response or energy efficiency. Please provide any information to help design such a platform, including how accessible it should be to multiple providers.**

As noted in comments concerning the Distribution System Planning Improvements, we believe that this usage information – properly protected for privacy and cybersecurity – should be made available to consumers and multiple vendors.

It should involve minimal latencies (one minute or less), so that responses to market signals and tariffs can be timely and economically meaningful. In instances where AMF has failed to live up to its promise, failure can often be traced back to lack of data access and the lack of quantification of customer and societal benefits. Therefore, in order to achieve the full benefits of AMI, the data platform should leverage customer engagement and provide data presentment back to the customer. A customer-facing portal should have the ability to provide customers with their interval data, personalized insights about that data, and tools that empower the customer to take actions to better manage their energy use through energy efficiency and demand response. Third parties should be enabled and engaged in this effort. Utility regulators should request annual reporting, as one way to ensure that the value of the investment is maximized

6) **Development of a shared communications network among existing wireless network operators, the electric utility, and other infrastructure providers can significantly reduce capital costs for ratepayers. Please provide any considerations to inform formation of a shared communications network.**

Please see our comments regarding partnership models.

[12] There may be exceptions to this statement, such as income eligible customers with very high peak demand resulting from air conditioning load. However, unless programs such as demand management are automated, they are unlikely to yield significant system benefits.

Conclusion

NECEC and AEE Institute reaffirm our commitment to helping Rhode Island capitalize on its unique position to transform its electric grid to meet the needs of the advanced energy future. The initial considerations on utility compensation and questions on advanced grid capabilities put forth by your agencies take Rhode Island another step closer to the achievement of this ambitious undertaking. Moving forward with the elements and refinements discussed here will help ensure that the electric utility business model keeps pace with and adapts to the rapidly evolving power sector and the many energy, economic, and environmental benefits that it brings.

NECEC and AEE Institute appreciate the opportunity to provide your agencies with these comments, and we look forward to our continued involvement in this process.