May 19, 2017

Macky McCleary	Carol J. Grant
Administrator	Commissioner
Division of Public Utilities and Carriers	Office of Energy Resources
89 Jefferson Boulevard	One Capitol Hill
Warwick, RI 02888	Providence, RI 02908

Re: Notice of Inquiry into the Electric Utility Business Model and Request for Stakeholder Comment

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' May 1st Notice of Inquiry into the Electric Utility Business Model and Request for Stakeholder Comment.

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,

Peter Rothstein, *President*
NECEC

Janet Gail Besser, *Executive Vice President*
NECEC

Lisa Frantzis, *Senior Vice President*
Advanced Energy Economy

Cc: Hannah Polikov, AEE
Ryan Katofsky, AEE
Jamie Dickerson, NECEC

Notice of Inquiry into Rhode Island's Electric Utility Business Model and Request for Stakeholder Comment

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 undertaking the Power Sector Transformation initiative. We greatly appreciate the opportunity to respond to this *Notice of Inquiry into Rhode Island's Electric Utility Business Model and Request for Stakeholder Comment, issued May 1, 2017.* This is a timely effort as commissions around the country are actively taking steps to address the substantial changes that are taking place within the electric industry. Technology, customer expectations, fundamental economics and state policies are changing quickly, placing pressure on the existing utility business model. NECEC and AEE Institute appreciate the opportunity to participate in and support this effort.

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 electric utility business model in Rhode Island in response to the May 1 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 and "utility-of-the-future" 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 business model reforms. In these comments, we have based our responses to the questions posed in the May 1 Notice 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.

1) What functions should the electric utility perform?

The structure and function of the future electric utility and the role of third parties is a foundational question that must be addressed before delving into the utility business model and how it should be compensated for the services it provides. Our vision of a future electric utility is as an integrator and market enabler, where the utility operates the grid as both a physical platform and market platform. The utility would own and invest in the platform infrastructure and operate this platform to integrate and coordinate assets and services owned and provided by third parties and customers. The utility's primary focus should be around managing the increasingly complex grid and not just in operating the connected grid edge technologies. As we move towards a platform system, it is important to keep in mind that the utility will need to manage the entire system and coordinate across all functions on the platform in order to ensure that it functions properly.

We believe the scope of what the utility can own and the services it can provide should be defined in detail so that parties understand what elements of the system are regulated utility assets and functions and what elements are provided via the competitive market. Specifically, we believe that the regulated utility should be limited to owning assets and providing services that are truly monopoly functions. We also believe that services that can be provided by distributed energy resources (DERs)[1] could and should generally be procured as a service through a market-based approach. However, until a time that market-based approaches for energy efficiency are proven at scale, it is important to continue the incentive based mandated energy efficiency structure to ensure that Rhode Island continues to achieve load reductions to support its energy and climate policies. We have provided a full breakdown below of which functions we believe should be provided by the utility and which should be provided by third parties (based on the potential functions laid out in the NOI).

Reliability services, such as pole and line maintenance, circuit reconfiguration, undergrounding, power factor correction, distribution system engineering and voltage variation optimization should be the responsibility of the utility. In addition, reliability services, such as grid hardening and reducing and mitigating power outages, should be a top priority for the utility. As such, the utility should prioritize reliable power for critical service areas including prisons, emergency services, and hospitals to ensure that adequate power will be available in emergency situations. However, the utility should still be required to follow a procurement process for these and other services from DER providers if they can fill the reliability need in a more cost-effective[2] manner than traditional solutions.

[1] We define DER broadly to include distributed generation of all types (including solar, wind, combined heat and power, fuel cells, and other technologies), energy efficiency, demand

[2] We define "cost effective" broadly in that it be based on a comprehensive benefit-cost analysis that takes into account the state's overall policy objectives.

Connectivity services including operation of the communications backbone to support distribution line automation and to enable potential advanced metering functionality and the growing internet of things is a new function that could be provided by the utility but also could be provided by third parties.

Network integration services, such as scheduling, multi-directional power flow and management services should be the responsibility of the utility. However, utilities and third parties may both provide certain network integration services such as distribution system planning and data analysis for load, voltage, and hosting capacity. Value-added services such as storage-based power "loan" services and electric vehicle charging services should generally be left to third parties.

Transaction management services, such as aggregation, clearing and settlement among parties, integration of DERs with ISO-NE markets, and metering customers could be provided by the utility but should all be open to third parties. While you do need a core transaction settler, you can have multiple aggregators and integrators of DER with ISO-NE markets.

Customer engagement services[3] should be provided by the utility and by third parties. Specifically, the utility should continue to provide, as part of a standard offer service, customer service, billing, dynamic rate programs and education about energy options including DERs. Energy services such as home energy optimization, appliance automation, intelligent load management, and backup energy services including energy storage, energy efficiency program delivery, and customer support should be left to the competitive market, either by utilizing companies acting as contracted agents of the utility (i.e., energy efficiency program delivery and appliance automation) or via unregulated third parties (i.e., home energy optimization and backup energy services). However, there may be instances where a market failure prevents or inhibits the competitive market from adequately serving a segment of the market (e.g., low income) or where market development is needed (e.g., new or emerging technologies). In those instances, the utility can play a role temporarily until such a time that better energy policy

[3] We believe that many of these resources, such as energy efficiency, should be thought of more broadly than just customer engagement services as they can provide significant other value to the grid.

can be enacted to resolve the failure and foster a fully animated, competitive market develops. In those instances, the role of the utility should be focused on helping create that competitive market, and there should be a review process overseen by the PUC to determine at what point regulated utility participation is no longer needed.

Are there additional functions not described here that should be included as a strategic focus of the electric utility?

As the grid becomes more dynamic and complex and as utilities invest in new “smart grid” technologies and capabilities and data becomes more available, it will become a growing challenge to protect hardware, software, and data from bad actors looking to do harm. Vulnerabilities could further expand to the transportation sector, where networked electric vehicles could potentially be integrated into the grid. The digitization of the electric grid will make cyber-security and cyber-resilience a critical responsibility and focus of the utility of the future.

In this changing environment, electric utilities of the future will have an important role to play in unlocking innovation. As NECEC described in its August 2014 report, *Leading the Next Era of Electricity Innovation: The Grid Modernization Challenge and Opportunity in the Northeast*,

> *[D]istribution utilities across the Northeast must continually adapt to new technologies and changing energy needs, becoming active partners with the region’s advanced energy companies and innovative system integrators of new technologies. Regulators should support these innovation efforts by allowing utilities to establish budgets for demonstration, testing, and integration and share accelerated learning about the performance, cost, and capabilities of these new technologies. These innovation activities would be consistent with the modern utility’s role as an active system operator and integrator of distributed and advanced energy technologies and would ensure that the Northeast’s utilities will*

> *be positioned to take advantage of cutting edge technologies and capabilities.*[4]

The subject of utilities' risk appetite and how utilities look at innovation under their current business model was discussed at the April 24, 2017, Utility Business Model Technical Session. Under the current regulatory framework, utilities are not given support or incentives to test and deploy new ideas and innovative technologies. To transform the power sector, however, the utility of the future will have to take on this role, implementing demonstration projects to test new technologies, business concepts and strategies. To support this new role, regulators should approve budgets for cost recovery of well-defined pilots or demonstrations that have the potential to improve the operation and efficiency of the grid to the benefit of customers.

Utilities are increasingly being tasked - sometimes directly, sometimes indirectly - with helping states meet their environmental targets such as GHG emission reductions. As such, the utility should be responsible to the state to align to such efforts and take policies and goals into account in their planning and forecasting processes.

Finally, utilities will have a role to play in enabling access to data available now and the massive amounts of granular data that will become available through enhanced connectivity services. It will be the utilities' role to ensure timely and convenient access to both customer and system data to stimulate innovation and enable third parties and customers to devise solutions to meet the needs of the future electricity system. This role may include establishing data access standards, customer authorization procedures and/or potential data exchanges. We support using the US Department of Energy's Green Button program in furtherance of this objective.[5]

To the extent certain activities now being performed by the utility may be performed by other market actors, what type of oversight should be in place to protect customer interests?

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[4] *Leading the Next Era of Electricity Innovation: The Grid Modernization Challenge and Opportunity in the Northeast*, August 2014, p.2.

[5] Customer authorization to receive competitive energy supply should also constitute authorization for the utility to provide granular usage data to the customer's retail supplier of choice.

While we understand the need for regulators to protect consumers who engage with private companies/third parties providing energy products and services, great care should be taken with respect to protecting consumer interests while still fostering a growing competitive market. While it is important to set rules and definitions for those that “play” on the grid, third parties should not necessarily be considered a “utility” and thus subject to all rules governing utility businesses. Private companies/third parties are already subject to a wide array of federal, state, and local regulations and conditions and duplicating these existing protections would be inefficient, not cost-effective and would potentially stifle the market. Additionally, it is important to note that these companies are likely to have ongoing relationships with both the utility and customers and so they already have a strong business incentive to treat customers well, be transparent, and have good customer service.

Contracted agents of the utility should not be subject to additional oversight from the Commission, as their relationship with the utility already subjects them to compliance with rules that govern the conduct of utilities.

In situations where third parties offer services to the utility, the Commission should focus on oversight of the utility’s execution of the contract and contract term, and not regulation over the third parties themselves. The contract with the utility should set the terms for delivery of those products or services and be enforceable generally under contract law. However, the PUC and DPUC should ensure that customer protections, such as data security, privacy, and marketing practices, are included in contracts between third parties and the utility as needed based on standards set by the Commission.

Adding unnecessary Commission oversight of other market actors also risks placing an unsustainable administrative burden on Commission staff, which would have the effect of slowing down the growth of the market. In considering this issue, the Commission should only exercise oversight on non-utility actors where a well-defined need has been identified, and for which regulatory oversight is an appropriate solution.

Finally, third parties that interact directly with ISO-NE should not be subject to additional requirements or Commission oversight. Companies that participate in wholesale markets must already adhere to a large number of tariffs, manuals, and rules and incur stiff penalties for non-compliance. Adding on to what are already substantial requirements risks duplicating these requirements and increasing compliance costs without providing additional benefits.

Many of the functions described here require the utility to manage complex technology systems. What kind of regulatory approach could address the risk of technology obsolescence?

The electricity system is complex and in recent years technology has been rapidly changing and improving. The risk of technology obsolescence has therefore increased greatly and will continue to be an issue. This will make distribution system planning more important than ever. Utilities must think long term in their planning and consider optionality when making investment decisions (i.e., making investments that allow for flexibility as circumstances change and that do not box them in to specific investments or technologies in the future). For example, a utility using optionality investing may make a non-wires alternative (NWA) investment that defers a traditional infrastructure investment for ten years. In this situation, the utility makes a business decision concluding that the NWA and the flexibility it provides are worth more than the expensive traditional investment that carries the risk of technology obsolescence or of becoming stranded in the future. In ten years the utility will still have the option to make the traditional infrastructure investment, but they will also have the option to make another NWA investment, or they may have a new technology solution, which does not exist today.

Another approach is moving towards a system where the utility procures more services in lieu of owning most assets themselves. This would move any potential technology obsolescence risk to the third party service provider rather than to the utility. For example, procuring software as a service (SAAS) that is developed and hosted by a vendor in the cloud rather than investing in traditional on-site hardware and software allows the technology to be more easily and more cost-effectively updated and gives flexibility to switch to another vendor and product as utility needs change. A move away from capital investment and toward more procurement of services has important implications for the utility business model, which we discuss in more detail below in our answers to Question 2. The Commission should consider setting clear guidance and incentives for utilities to invest in SAAS. For example, the New York Public Service Commission included language in its Track 2 Reforming the Energy Vision Order that clearly states its support for utilities to earn a rate of return on SAAS investments.

In addition, the Commission should investigate updating depreciation schedules for new kinds of utility investments, especially rapidly changing technologies such as communications hardware and software. Traditional utility investments generally have long depreciation schedules that can exceed thirty years. The pace of innovation today is making some of these investments obsolete before they have been fully depreciated, which could mean future customers will be paying for past investments that are no longer useful or that have been replaced. Setting new depreciation schedules for rapidly changing technologies could address utility reluctance to invest in these new technologies needed to modernize the grid. For example, utilities that have already invested in automated meter reading (AMR) meters, may be concerned about the regulatory treatment of these assets if they are abandoned before the end of their useful lives, and replaced by advanced metering infrastructure (AMI) or advanced metering functionality (AMF).[6] How to address this potential "stranded cost" should be considered and guidance given to the utility.

2) How should the utility be compensated for each of the functions it performs?

Utilities should be increasingly compensated based on their performance or the outcomes they achieve rather than the inputs or investments they make to achieve them. While cost of service regulation may continue to set a baseline for rates to be charged to customers, its traditional application sends the inefficient and possibly incorrect signals to utilities regarding the types of investment needed to advance power sector transformation. Cost of service regulation is based on the costs utilities incur to provide service and its historic application has provided recovery of and return on capital

[6] AMF is a broader term than AMI that leaves the door open for a wider range of technologies and solutions to provide the same or similar capabilities that AMI offers.

investments, providing an incentive to increase their rate base and, in turn, their profits. However, this business model is increasingly incompatible with new technologies and delivering value to customers. Under the current cost-of-service model, if the utility leverages an asset owned by a customer or a third party to support the grid rather than invest in its own solution, the utility will shrink its capital expenditures, its main source of profit. To align utility incentives and maximize the use of existing utility infrastructure, utilities should be allowed to earn the same return on procured services as on capital investments, a concept more simply defined as *infrastructure as a service*. Traditionally, utilities earn a return on equity on their capital expenditures (e.g., traditional T&D investments), whereas operating expenditures (e.g., software services, contracted DER solutions) are simply passed through to customers. Utilities are therefore incentivized to drive up their capital investments and drive down their operating expenditures between rate cases, which can distort utility investment decisions. New regulatory approaches that take a holistic view of capital expenditures (Capex) and operating expenditures (Opex) should be explored to address this distortion, which may inhibit utilities from choosing.

As the grid modernizes and DER penetration increases, other types of investments will be necessary, and new utility services will emerge. Aligning utility financial incentives with the needs of the changing grid and public policy goals requires changes to the way the utility makes money. Performance incentives and regulatory policies that reward the utility for desired outcomes as opposed to inputs are approaches that promote this alignment. If structured properly, performance incentives (which are discussed in more detail in the next section) will motivate utilities to achieve desired outcomes such as peak demand reduction, DER adoption, access to data, and customer engagement. Performance incentives that better align utility shareholder interests with desired policy outcomes and the interests of customers have the potential to provide the utility with the motivation to deliver cost reductions and improve service quality. Forward looking, outcomes-based regulation is a natural extension that works well with the existing cost-of-service model and can be implemented relatively quickly to begin to move the utility in the direction of becoming a more innovative, customer-focused company.[7]

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[7] Please see discussion in NECEC's paper, *Leading the Next Era of Electricity Innovation: The Grid Modernization Challenge and Opportunity in the Northeast*, August 2014, pp.12-14.

3) What is the appropriate role of performance based regulation in utility compensation and what metrics should drive utility compensation?

Multi-Year Rate Plans

We strongly support the concept of moving towards long-term (three to five year), forward looking rate plans, as they provide stability for utilities, cut down on the cost of administrative oversight and process, and can play an important part in providing utilities with the right incentives to meet state policy objectives. Having a predetermined fixed rate case period provides a financial incentive for the utility to increase operational efficiency and reduce costs because they prevent the utility from filing a new rate case to recover their costs if they are not operating efficiently, therefore benefitting all customers. In addition, because multi-year plans replace annual or ad hoc rate cases, less time will be spent in the hearing room, with more time spent enhancing the system and serving customers.

Performance Incentive Mechanisms

As mentioned earlier, we strongly support implementing both broad and targeted performance incentive mechanisms (PIMs) that tie designated financial rewards and penalties to specific performance metrics. PIMs shift the focus of the utility from static cost minimization to enhancement of value as utilities are given incentives to improve performance that leads to an increased return on investment. Metrics 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.

Rhode Island is well suited to utilize an enterprise-wide performance based regulatory framework based on past experience and as stated in the May 1 Notice.

> *Rhode Island has previously recognized that cost of service regulation is not always, in itself, adequate to achieve state energy objectives. For example, the*

2014 Renewable Energy Growth Program, the 2009 Long Term Contracting Standard for Renewable Energy, and the 2016 System Reliability and Least-Cost Procurement each establish topical, performance based incentives to correct perceived gaps in cost of service regulation. Reform of the utility business model can build upon the success of these existing performance incentive mechanisms.

As Rhode Island moves towards a broader performance-based framework, existing performance incentive programs, such as statutory incentive programs for renewable energy and energy efficiency, should be incorporated. This may mean that some existing incentives may go away and others may be incorporated into the broader performance-based framework.

We also provide the following recommendations for the structure of potential PIMs. PIMs should be large enough to have the desired effect on utility behavior, but they should also be capped to protect consumers. Furthermore, to counterbalance the counterproductive incentives in the current regulatory model, consideration should be given to weighting PIMs towards outcomes that will reduce capital expenditures. Finally, the Commission should generally consider symmetrical incentives (rewards and penalties) instead of asymmetrical incentives. The relative size of penalties and rewards could change over time as the level of incentive to require utility action changes (i.e., as the performance-based approach become business as usual, utilities will not need as much targeted incentive to act).

The Commission should award incentives as fixed sums at predefined performance levels rather than provide them as changes to a utility's allowed return on equity (ROE). There are several reasons for this recommendation. Primarily, rewarding a utility on the outputs it provides by adjusting ROE (an input incentive) mixes signals to the utility in a way that may not be helpful. Incentives tied to ROE are correlated with total capital spending, which creates an unintended link between capital investment and incentive level. For example, an incentive tied to good performance on a system efficiency metric would increase if a utility spends more to achieve it or if the utility spends more on an unrelated substation upgrade. However, customer benefits would not also increase. So good outcome metrics end up driving only part of the incentive amount. In general, if incentives are tied to the size of the utility's rate base, general increases in capital expenditures will increase the size of the reward even if no additional funds are spent to achieve the desired outcome or if no greater performance were achieved. And if the reverse happens, and a utility becomes more capital efficient and decreases its capital expenditures, it would be counterproductive to signal to a utility that its good performance on public policy goals is any less valuable in this scenario by automatically decreasing the rewards that are tied to ROE. As new regulatory structures attempt to maximize benefits and encourage efficiency with inputs, trying to encourage greater performance by setting up incentives as a function of inputs may send a utility a financial signal that runs counter to the goals of performance based regulation.

Conversely, if incentives are based on fixed dollar amounts, the Commission could use a utility's current ROE as a baseline for the initial award amounts and then in future years, adjust the size of pre-defined awards as needed based on metrics that are consistent with the utility's size, such as the number of customers served.

There are many potential PIMs from which to choose, however the advanced energy community believes regulators should focus on objectives where there is most need for improvement, where there are opportunities to pursue regulatory priorities, and where there is opportunity for change. Specifically, the advanced energy community believes performance metrics should serve as motivating instruments for the utilities to improve customer engagement, operational reliability and efficiency, environmental sustainability, and market innovation. The following is a list of sample metrics that we recommend implementing in the near term, because they are linked to value across multiple categories of performance. These could be implemented alongside traditional service quality and reliability metrics.

- Data access (e.g. timeline of data request responses, ability for customers and third parties to access data)
- Energy efficiency (e.g. kWh and therm reductions relative to baseline)
- System efficiency (e.g. peak load reduction)
- Third party resource deployment (e.g. MW of DER deployed)
- Interconnection and DER integration (e.g. speed of processing valid interconnection requests)

- Customer engagement (e.g. percentage of customers that have access to tools, information, and analysis that lead to desired customer actions)
- Emissions reduction

Conclusion

Rhode Island is in a unique position to transform the electric grid by controlling the long-term costs of the electric system, giving customers more energy choices, and by building a smarter and more flexible grid to reduce costs, improve reliability and resiliency, integrate more advanced energy generation, and reduce environmental impacts. In order to do so, the utility business model needs to evolve and regulatory frameworks must align the behavior and financial interests of the utility with public interest objectives and consumer benefits, and rewards utilities for achieving well-defined desired outcomes.

We appreciate the opportunity to provide the Commission these comments and we look forward to our continued involvement in this process.