Innovari, Inc.
Comments on
NARUC Manual On Distributed Energy Resources Compensation

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The NARUC Staff Subcommittee on Rate Design Manual ("Manual") provides a great primer for regulatory considerations when looking at rate design and distributed energy resources ("DER" sometimes also referred to as "edge of grid resources"). Our comments are intended to support the great work that has been done and add additional considerations to the dialog from our historical experiences working in utilities and on regulatory staffs and our current experience working as a third party in partnership with utilities to integrate distributed energy resources.

We are also attaching a White Paper, Creating A Regulatory Framework For Demand-Side Investment In The Distribution Grid Equivalent To Capital Investment in Generation, by Suedeen Kelly and Porter Wiseman ("Whitepaper") for your consideration. The Whitepaper provides important insight into how the existing regulatory compact can be leveraged to support DER and the utility’s ability to effectively incorporate these resources into the grid. The Whitepaper includes two key points: First, an overview of how DER resources fit in the current model as a utility capital investment. Second, it introduces an elegant concept of paying utilities for kilowatt-hours dispatched, a method which can eliminate the disincentives of both decoupling and traditional ratemaking based on kilowatt-hours sold.

Introduction

At Innovari, we don’t just dream of a better future; we’re building one. We’re improving how the world uses energy by helping to optimize the entire energy value chain. While we are a third party, our broad and diverse history in the industry as well as our Company’s commitment to the public good provided by the grid, allows us to understand that utilities, regulators and customers need a vehicle that will enable mutually beneficial collaboration. Innovari, and its team, has been working for the last decade to create a vehicle that enables this collaboration. A vehicle that will allow the customer, the regulator and the utility to each meet their desired objective working together in partnership.

The electricity enterprise is a very complex system of systems. These systems are not only complex from a technical and engineering perspective, they are also very complex from a business and regulatory perspective. To add even more complexity, this system of systems isn’t even constrained to just the electric system. The electric system is also interconnected with other energy systems. As the polar vortex storm proved, the effect of weather on the gas consumption of individuals could dramatically impact the availability of gas for electric generation and thus the reliable supply of electricity. Even our industry’s best “experts” (technical, regulatory or other) are frequently surprised when something has been studied and studied and then is changed causing an unanticipated result. These recent events and realizations have created several new efforts around our nation to improve the resiliency of our networks with new technologies to help protect against unplanned events or natural disasters.

Most important in this discussion is that no two utility systems are exactly the same. Most utilities have over a hundred years of rate making history and infrastructure investment that has been laced with social policy throughout that entire history. This diversity makes it impossible to draw broad distinctions or create a single uniform policy. As the Manual emphasizes, each state’s regulators must closely
examine the situation for each utility in their jurisdiction through the eyes of the current regulatory structure.

Even the most logical, well-intentioned people may come to odds with each other because they find they are discussing the same problem but from different perspectives. The regulatory process must engage with the complex systems of systems and a variety (and growing number) of stakeholders. Unfortunately, the complexity and the stakeholder process make it is quite easy for an ill-intentioned person or group with single purpose special interest to create dysfunction and contention.

We believe the grid provides an essential public service and the utility has been, and will continue to be, the steward of that public good. Recent history has shown special interest groups success in driving structures or concepts as a means to justify a business model that works for them, not for the greater good of all connected to the grid. With more and more DERs coming to the grid, it has never been more important for regulators and utilities to work closely together to solve these problems for the benefit of all stakeholders. The Manual, and the discussion it sparks, will be an important part of helping bring these issues to light and create more productive and effective conversations.

Electricity is like no other “product” in the history of mankind. Once you have it, it is no longer a luxury, but a necessity. We have seen real world examples of this dynamic through our work with developing nations around the world. The reality is that electricity isn’t a standard product. It is fundamental to our economy and sometimes to our survival. Reliability, resiliency and affordability are crucial. The essential nature of the product and its place as a natural monopoly, which continues for the distribution grid across all jurisdictions, gave rise to the regulatory construct we have today. While this construct has served our nation well and has been adopted literally across the entire world, it does add complexity to the adoption of new technology and the participation of third parties that should not be easily dismissed. But “throwing the baby out with the bathwater,” either by rejecting the role of new technology, or by ignoring the unique regulated responsibility of the utility, does not seem a prudent or wise approach to solving these issues. Instead, through collaboration and conversation, we can seek solutions that allow all stakeholders a positive outcome.

We applaud the effort that has been put forward in the Manual and the clarity it provides to these key issues in our industry today. We hope these comments will provide further examples and insights that might be helpful in considering the path forward for each in utility in each state of our country.

**Technology Change and Implications**

It is important that there is a clear recognition of key technology changes in this conversation. We have become very focused on pursuing objectives or initiatives that were started more than 30 years ago. For instance, the concept of Time of Use (“TOU”) tariffs emerged because the utility had no economical means by which to control and/or manage demand as an effective part of their resource mix. The idea behind TOU prices was that if we could engage customers and have them make better decisions at key times, we could improve how our grid operates. While significant changes in price signals may drive behavior that benefits the grid, subjecting a customer to an open market price that can range from 6 cents/kWh to more than 100 cents/kWh is politically and practically problematic. What if, for example, they have lifesaving equipment at their home that requires electricity?
Since the TOU construct emerged, low cost, secure, high speed, ubiquitous communication networks have emerged that can manage buildings and effectively enable DER’s at the edge of the grid. These technological changes are transforming the demand side into a legitimate and reliable resource for grid operators to see and manage in real time without subjecting customers to TOU volatility. Utilities can partner with their customers through “set-it-and-forget technology capabilities” that allow them to automatically reduce (or even increase) demand without impacting their customers’ comfort or business operations. This can be a clear example of how cooperation could revolutionize the industry. The ability to automatically and dynamically control demand can provide the opportunity to balance both central station and distributed intermittent resources such as solar and wind. The last 10 years have completely changed the possibilities and regulatory constructs need to be revisited with these new technologies in mind.

The Manual mentions the “hidden costs” in several sections. When TOU rates were discussed and introduced, no one imagined that utility costs for new Computer Information Systems would soar into the hundreds of millions of dollars. Nor did they envision a future where lawsuits would be filed to stop deployments of communicating meters. Yet once we were set on this path, there seemed to be no stopping the momentum. The telecommunication’s industry is often drawn on as a parallel to how the industry should respond to technological change. We would argue that many of comparisons are not accurate reflections between the two industries, there are some important lessons to be learned from telecommunications (and other industries).

The telecom industry when first unbundled originally pursued choice, choice and even more choice. They created more structures and pricing schemes and packages than anyone could have ever imagined. And suddenly consumers were receiving 50 page bills that were incredibly complex and very detailed but inevitably had charges that were incorrect, misstated or simply wrong. The complexity of the billing systems created high error rates, customer dissatisfaction and a high cost of IT systems and daily administration. Virtually every telecommunication provider has returned to very simple bundled pricing with none of the granularity or confusion. Learning from telecom’s failure, why would our industry seek dramatic complexity over simpler solutions? Why do we feel the need to re-learn this lesson? In this particular parallel, it seems that the telecom industry had the same peak issues, the same utilization issues, the same technology disruption issues and the same regulatory frameworks that were being modified to accommodate all of this. Could it be that special interest and big computer firms desire to sell new and complex systems to manage this and thus feel the need to support these concepts?

When we apply these lessons to the electricity industry, we need to consider that question and ensure that we are not simply riding a train that has gained some much forward momentum that we can’t stop it long enough to see that the tracks we are riding on were built so long ago they don’t actually go to the destination we now desire? The goal is not differentiation of prices, it is not visibility into every minute of every kWh consumed. The goal is a more effective utilization of our system assets, and thus lower cost, through the elimination of the peak 5% or 10% of the system hours. If there is now technological solutions that can do this automatically in partnership with our customers, why not recognize that and make use of the technology without disruption to customers or unnecessary regulatory constructs?

As is noted in the section on Transactive Energy (“TE”), for some things to work, it will require significant additional investment. TE requires AMI and communications technologies that do not currently exist and also specific policies to work. TE and TOU are good examples to highlight the potential “hidden costs” of decisions as we move forward. Much of the Manual seems to incorrectly assume that the metering technology and the billing technology exists to allow for these possible DER structures such as
TOU and TE to be measured and appropriately billed. The reality is quite the opposite. Enabling such a complex system is incredibly expensive for the utility and would increase costs for all customers. These excursions into large complex pricing structures to support TE and TOU are often short lived as customers do not want, and cannot bear, the complexity and risk that is inherent within these structures. We have the opportunity to leapfrog over the mistakes made by other industries and should make the most of that opportunity.

Perhaps a refresher on Occam’s razor would be in order – **The simplest answer is most often correct.**

The current role of the utility to operate the resources on its system, including communications enabled DER, is already in place. While technology is changing, we are not facing a technological disruption that would require us to eliminate the current regulatory construct. The wireless transmission of full power requirements to our homes or the invention of the portable Mr. Fusion machine from the *Back to the Future* movie are disruptions that would fundamentally deconstruct our entire industry. While DER’s are rapidly improving and fundamentally change the nature of our system from a one-way grid to a two-way grid, it is change that can be positive to the overall reliability and efficacy of our grid and that can fit in current constructs as it shown by the Akin Gump Whitepaper. It should not be viewed as a threat but as an opportunity. These technologies should be embraced to provide higher utilization of our existing networks while exploring the many other possible improvements we can make by working with customers and communities and distributing some portion of our resources in partnership with them.

**Who Owns DER?**

As the Whitepaper discusses, the current regulatory construct allows Utilities to own DER’s. However, much of the Manual seems to assume that DER would be owned only by third parties. While there will likely always be third party owned DER connected to utility systems, significant benefits can come from utility ownership of DER. These benefits include: stability and regulatory oversight of investment in DER, opportunity for utility investment in an era of limited load growth, increased likelihood that the resources will be planned and located where they will be most beneficial to the grid, ability for the utility to control and dispatch the resource for the benefit of the distribution grid, transmission grid or bulk power system as needed, and a growing partnership between utilities and their customers (especially commercial and industrial customers that can reduce demand and house significant generation or storage resources). It should not come as a surprise that if a utility planning group has the opportunity to place 100MW’s of DERs, that these resources would be placed in areas to relieve grid congestion, defer system upgrades or potentially be placed to provide improved reliability or grid balancing of other DERs put in place by private developers. The future should hold the opportunity for all stakeholders to own DERs, including the utility.

First principles should not be lost in rush to embrace new actors that possibly endanger the ability of distribution companies in the future to provide appropriate reliability at the lowest cost to customers. Replacing that essential role of distribution utilities model with un-needed complexity only adds cost and makes reliability more questionable at a time when we can instead make reliability improvements.

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1 Under the FERC Uniform System of Accounts (USoA), equipment “on the customer’s side of a meter” is classified as a distribution plant under Account 371, and it may be included in rate base if “the utility incurs such cost and when the utility retains title to and assumes full responsibility for maintenance and replacement of such property.” If the regulations of a given jurisdiction require that the utility lease these assets to the customer, or if that is the customer’s preference, the control devices can be accounted for under Account 372, which covers “Leased property on customer’s premises.”
DER’s that are intimately tied to supplying improved reliability and/or lower cost should be the province of the distribution companies within the regulated structures as it benefits all customers connected to the grid. All of these discussions should be founded on the basis of this is a business case exercise not a technology inclusion exercise.

Embracing these principles, we believe that the utilities should change a fundamental aspect of their planning process, the Integrated Resource Plan. Traditionally the Integrated Resource Plan was a top down vehicle that viewed planning from a system-wide perspective, but only from a scale resource approach. As utilities seek to leverage the benefits of DER, we would suggest that a bottom-up approach is more beneficial. With its intimate knowledge of the distribution grid (down to a feeder level), customer desires and overall resource requirements, the utility can play a key role in designing, operating and even owning key DER resources in a manner which benefits all stakeholders. Recent community solar programs are a great example of this success.

The future is clearly on a path of DER enablement. However, it also becoming very clear where these DER’s are being implemented. Solar and the 15% of consumers with back-up generation are generally the upper income bracket of our country. This has had the unintended consequence of a significant cost shift to those that cannot afford to implement these solar resources. Regardless, the reality is that DERs are likely to continue on this path where affluent customers can afford them and others cannot. However, it is very refreshing to see well-structured community solar programs emerge that allow all customers of any income class to participate, while being placed and planned in cooperation with all stakeholders. This is a perfect example of the power of the partnership between customer, regulator, utility and the communities they live in and serve. It is also a very clear example of why utilities should not be excluded from being a key participant in the ownership of DERs.

Define the Product

Beyond defining DER, a regulator must examine the result provided by the resource. Whether in markets or in regulated rate setting, any investment in DER products by the utility or by third parties should be compensated, or charged, based on the benefits, or costs, that it provides to the system as a whole, and not just to individual customers. In order for DER resources to provide systemic benefits, there must be secure communications to make it an integrated grid asset rather than an isolated (or interfering) resource. Some elements to be considered are dispatchability of the resource: can the utility or system operator dispatch the resource? Reliability of the resource: can the dispatch signal be confirmed in real time avoiding delayed and costly settlement and will the resource always show up? Locational value of the resource: is the resource located in an area where it can displace an otherwise necessary capital investment? Security of the resource: is the resource conforming to cybersecurity standards in its enablement to the grid? Not all DER’s are created equal and regulatory treatment of these assets should discern the various value streams based on the capabilities and placement of the resource. Technology will certainly drive improvements across the board for DER’s so it will be important to continuously assess the value streams so that DER’s may be properly classified into the proper product sets. For example, manual measure demand response that is activated by a call bank and individuals running around a facility to turn things off and then is settled 30-60 days later should not be considered the same product as a technology enabled, real-time, two-way verifiable closed loop and granularly controlled DER. These product sets must be differentiated to ensure proper value and cost attributions.

Time Horizon for Investment
There is significant discussion in the Manual around the appropriate time horizon for consideration of DER’s. Specifically, it says, “As the lifespan of most DER systems is generally 20 – 30 years . . .” and then further goes on to discuss that this is a short time horizon compared to the life of the distribution or transmission system. It should be clear that the context of these decisions should be with the understanding that we are creating and integrating assets that will be here for decades. Therefore, there should be little doubt that inventing short term constructs are likely to fail. However, as is also mentioned clearly, technology is changing rapidly and whatever decisions are reached have to be reached with the understanding that they will be revisited frequently to help ensure the desired goals are being met. This process should embrace technology and not be subject to historical constructs such as considering the meter as an artificial point of demarcation. The role of the distribution utility moving forward must include its ability to effectively partner with customers and the community and place resources, or aggregate resources, in the system where it provides the highest value.

Rate Design— Dispatched Capacity and Energy vs. Produced and Consumed

Utilities in the modern era of distributed energy resources do not just make, move and sell energy but must also integrate distributed intermittent resources and access demand side resources to balance the system in the most efficient and effective way possible. This complex era is not well served by rate design that depends on kilowatt-hours sold which simply encourages utilities to sell more electricity. Decoupling, the most common alternative, makes utilities indifferent to kWh sold, but also fails to properly encourage utilities to invest in flexible, resilient systems that can properly integrate DER. The Whitepaper discusses an elegant solution, whereby rates are based on kWh/dispatched that values the utility role as a system operator and eliminates the perverse incentives of alternatives.

Summary

This Manual provides a great opportunity for our industry and we applaud NARUC’s initiative, vision and effort. We hope that our industry will take this opportunity to step back from the details of programs, technology, and activities and remember the overall goal of reliable, cost effective electricity for all. With those goals firmly in mind, we encourage regulators to really examine current technology and remember that the grid serves us all. It is a public good and our responsibility to our country, our economy, our neighbors and our children is to protect the efficacy and viability of that grid. These issues will not be solved by pundits or politicians seeking quick headlines. This is a long-term discussion for very long lived assets. The historic partnership between the regulator and utility needs to be revived to adequately work through these complex issues. This partnership needs to be strengthened and maintained as we move together into the future.

Utilities are often hesitant to invest in innovative projects. This is often due to regulatory uncertainty or support for the utility to try these new things. While both regulators and utilities are excited about the possibility of technological advancement, they must balance any investment against increased costs, but that cannot come at the expense of doing nothing. Doing nothing allows only a singular approach from the rest of the interested stakeholders: Third party ownership and random placement of all DER assets. However, third party DER asset ownership does not always result in the least cost alternative or in system wide benefit. Regulators should be open to the additional value streams available through utility partnership with third party technology companies and encourage utilities to invest in the technologies that can integrate DER for the benefit of the grid and all customers. The concept of waiting for the next
best thing is no longer valid with the rapid pace of DER development. Utilities must be allowed to engage and move forward to adequately serve their customers with the resources and services these customers desire.

Utilities need to be proactive and embrace the edge of grid opportunities they have to partner with their customers and do things differently than they have done before. Regulators need to support outcomes that will drive the grid of the future that we all need and desire. Everyone needs to understand that there will be mistakes and lessons learned on this path to embrace the edge of the grid and be tolerant of these failures. These issues will only be resolved through conversation and cooperation, with the fundamental goal to protect and preserve this public good we call the grid. Arguments and lawsuits and long protracted cases do not help us move as rapidly as technology is moving. Conversation and cooperation produce positive outcomes. The inherent belief in our system to serve our people needs to be restored so we can move this industry forward with transparency and cooperation it needs today.

And while people like to make large, generic comparisons, the reality is that virtually every utility in every state is faced with a different set of historical circumstances and policy goals that encumber the assets of this public good. As the Manual talks about in detail, social programs, cross subsidies, stranded costs and a host of other specific circumstances invade every aspect of this conversation and make it impossible to have consistent national policy or frameworks to deal with all issues. So there is only one universal truth: regulators and utilities need to repair their relationships for the greater good of the customers and our grid and come together in partnership to define policy to protect our nation. Special interest groups are aptly named and singular in their focus. The job of the utility and regulator is always misunderstood and underappreciated and perhaps never more important in these next few years as these key issues are explored. The technological disruption of DERs is more fundamental to the very nature of how our grid works than any of the changes that have come before and will have far reaching effects, either positive or negative, based on how we approach and solve these issues together.

Thank you for the opportunity to comment. We support this ongoing dialog, and commend NARUC for its efforts. Please contact us if you have any questions or if we could provide additional insight or support.