NRECA
America's Electric Cooperatives

To: Quadrennial Energy Review Team
Energy Policy and Systems Analysis Office
Department of Energy

From: National Rural Electric Cooperative Association

Date: July 1, 2016

Re: NRECA Comments on Phase II of the QER

The National Rural Electric Cooperative Association (NRECA) and its 900 member cooperatives around the country appreciate the opportunity to participate in the second phase of this Quadrennial Energy Review (QER). Since the January 2014 issuance of the Presidential Memorandum that launched the QER,[1] NRECA and its members have actively engaged in the QER process by submitting comments on various issues and, where possible, participating during the nationwide public forums and stakeholder sessions in order to ensure that the co-op perspective is brought forward.

In formulating its comments, NRECA has opted to create a cohesive document that both reflects the comprehensive purview of this phase of the QER and also formalizes and congregates NRECA's views and recommendations on the current state and trends in the electric utility industry and some of the unique challenges that cooperatives face in ensuring reliable, affordable, safe, and sustainable power in an increasingly uncertain future. To aid in navigating the document with respect to the Framing Questions DOE posed in its February 4, 2016 Stakeholder Briefing Memo,[2] please see the below recommendations gleaned from the comments and the associated Framing Questions to which they are responding. For convenience in cross-referencing the

[1] https://www.whitehouse.gov/the-press-office/2014/01/09/presidential-memorandum-establishing-quadrennial-energy-review

[2] http://energy.gov/sites/prod/files/2016/02/f29/Second%20Installment%20Briefing%20Memorandum_0.pdf

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recommendations with DOE's Stakeholder Briefing Memo, the recommendations below have been re-ordered to fit the order of the Framing Questions, and reference the section of NRECA's comments where a more thorough discussion may be found.

<u>**Recommendations**</u>

Generation Portfolio, Reliability, Supply Chains, and Equity

1. Reliability and affordability must remain priorities under any scenario. [Section 1]
2. More time is needed to construct and put into service the necessary additional infrastructure to support the transformation of generation portfolios. [Section 1]
3. DOE's efforts to streamline and simplify needed infrastructure planning and development are appreciated and should continue. [Section 1]
4. DOE should revisit the conclusions in its 2015 report on "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector." [Section 1]

Distributed Energy Resources (DER): Demand Response, Distributed Generation, and Distributed Energy Storage

1. One-size-fits-all approaches to regulatory and market regimes should not be encouraged. [Section 3]
2. Policies should be designed to allow utilities to optimize the portfolio on behalf of their consumers. [Section 3]

Grid Operations and Planning

1. More time is needed to construct and put into service the necessary additional infrastructure to support the transformation of generation portfolios. [Section 1]
2. DOE's efforts to streamline and simplify needed infrastructure planning and development are appreciated and should continue. [Section 1]
3. DOE should revisit the conclusions in its 2015 report on "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector." [Section 1]
4. Long-Term Planning Must Be Incentivized in the Interests of Reliability. [Section 2]

Electricity Consumption and Energy Efficiency by Sector (Residential, Commercial, Industrial, Transportation) Status, Trends, and Barriers

1. DOE and EPA must correct the "source" energy factor used in energy efficiency policies. [Section 7]
2. "Incremental emissions factors" should be used instead of "marginal emissions factors" to account for new energy loads' impacts on energy efficiency programs. [Section 7]
3. "Emissions efficiency" should be considered instead of "energy efficiency" in energy policies designed to reduce emissions. [Section 7]

Electricity Markets

1. Co-ops should continue to have the right to act as the intermediary between retail consumers and the wholesale markets. [Section 2]
2. Bilateral markets exist, and those markets serve a valuable purpose should be supported. [Section 2]
3. Long-Term Planning Must Be Incentivized in the Interests of Reliability. [Section 2]
4. One-size-fits-all approaches to regulatory and market regimes should not be encouraged. [Section 3]

Electricity Valuation

1. Valuation methods should be technology-neutral. [Section 5]
2. Valuation methods should recognize the valuable contribution of existing hydro and nuclear resources to grid stability and reliability. [Section 5]
3. Valuation methods should not be tailored to support one form of risk assessment and management over another. [Section 5]
4. Resources should not be credited with societal benefits that are not related to regulatory compliance, through valuation models or any other mechanisms. [Section 5]

Innovation and Technology

1. Funding available for technology transfer should be increased considerably from current levels to have measurable impact and progress, and also to enable projects that assist consumers in understanding the implications of technologies – both positive and negative. [Section 4]

2. Technology transfer efforts at DOE and other federal agencies should focus on enabling a framework to support all technology transfers and explicitly leave the decision to adopt a certain technology to the local communities rather than mandates and regulations. [Section 4]
3. An R&D and technology transfer strategic plan should be created that contains well-defined and transparent success metrics. [Section 4]
4. DOE and other federal agencies should provide funding for programs to focus on the development of relationships and partnerships with utilities and private sector entities as part of a structured plan, as well as provide funding for specific technology transfer projects that are in the national interest. [Section 4]
5. Technology transfer should be treated as an ongoing activity, with improvement in metrics continually measured from a baseline, instead of projects or initiatives with specific start and stop dates. [Section 4]

Jurisdiction and Regulations

1. The federal-state jurisdictional situation demands clarification. [Section 2]
2. Co-ops should continue to have the right to act as the intermediary between retail consumers and the wholesale markets. [Section 2]
3. One-size-fits-all approaches to regulatory and market regimes should not be encouraged. [Section 3]
4. Policies should be designed to allow utilities to optimize the portfolio on behalf of their consumers. [Section 3]

Environment

1. Reliability and affordability must remain priorities under any scenario. [Section 1]

Resilience

1. DOE and the National Labs should pursue the creation of resiliency resources other than metrics. [Section 6]
2. We encourage DOE to be a research partner with industry in focusing on practical, near-term applications. [Section 6]

Physical and Cyber Security

1. We encourage DOE to be a research partner with industry in focusing on practical, near-term applications. [Section 6]

Employment and Workforce Development

1. DOE should continue programs like the Utility Industry Workforce Initiative and GEARED. [Section 8]
2. DOE should continue to provide grants that encourage the development of curriculum needed by utilities. [Section 8]
3. DOE should focus on improving the image of energy jobs at the high school and college level. [Section 8]
4. DOE should explore opportunities in convening a higher education consortium to explore ways in addressing workforce shortages in the energy industry. [Section 8]

Accompanying the comments and recommendations, NRECA is submitting a few supporting documents. NRECA has already submitted its report "The 51st State: A Cooperative Path to a Sustainable Future", which describes the Consumer-Centric Utility Business Model in greater detail. NRECA is also submitting the following as appendices to its comments:

- "Capacity Markets: A Path Back to Resource Adequacy" – an article by NRECA's Jay Morrison from the May 16, 2016 issue of the Energy Law Journal.
- "Environmentally Beneficial Electrification: Electricity as the End-Use Option" – an article by NRECA's Keith Dennis from the November 2015 issue of the Electricity Journal.
- Three case studies on the approach of three cooperatives – Bandera Electric Cooperative, St. Croix Electric Cooperative, and Washington Electric Cooperative – to rate design.
- A survey from Power System Engineering, Inc. on Electric Cooperative Fixed Cost Recovery.

NRECA looks forward to continued engagement and participation with DOE in this QER effort.

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Introduction

The National Rural Electric Cooperative Association (NRECA) is the national service organization dedicated to representing the more than 900 consumer-owned, consumer-governed, not-for-profit cooperative electric utilities and the consumers they serve. Our member cooperatives were formed to provide reliable electric service to their member-owners at the lowest reasonable cost in a safe and responsible manner. More than simply a service, electrification transformed nearly every aspect of the lives of millions of rural Americans, literally uplifting them from darkness by bringing quality of life and innumerable health benefits, eliminating household drudgery, and vastly increasing productivity and economic well-being.

Distribution cooperatives are the foundation of the electric cooperative network. They are the direct point of contact with the member-consumers in the delivery of electricity and other services. Sixty-five *Generation & Transmission cooperatives* (G&Ts), owned by the distribution cooperatives they serve, provide wholesale power to 668 of the 838 distribution cooperatives through their own generation or by purchasing power on behalf of the distribution members. Both distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

Today, our member cooperatives provide electricity to over 42 million people – or roughly 12% of the U.S. population – in 47 states, and they do so in an environment of ever-increasing regulatory mandates, geographical constraints, and demographic challenges. Rural electric cooperatives serve large, primarily residential, low-density geographic regions where the costs of infrastructure and of providing service are high and the revenues are low. Data from the U.S. Energy Information Administration (EIA) show that rural electric cooperatives serve an average of 7.4 consumers per mile of line and collect annual revenue of approximately $15,000 per mile of line annually. In contrast, investor-owned utilities (IOUs) serve an average of 34 customers per mile of line and have annual revenues of approximately $75,500 per mile of line. Electric cooperatives have a significantly higher proportion of residential consumers than municipal and investor-owned electric utilities.[3] Due to this geographically-determined disparity in distribution costs and revenues, the residential

[3] Information taken from U.S. Department of Energy, Energy Information Administration EIA Form 861.

electric rates of 63% of rural electric cooperative members are higher than those charged to the customers of nearby IOUs. These higher rates impede the economic recovery of rural communities.

The low population density of rural areas affects not only the cost of providing electricity, but also electricity demand, making rural Americans even more vulnerable to rising electricity costs. Together, these forces combine to establish rates that are higher compared to those charged to customers of nearby IOUs, forcing already-disadvantaged rural customers to pay an even higher percentage of their income on electricity. Because many rural residents do not have access to natural gas and must depend on electricity and expensive propane and heating oil for warmth during the cold winter months,[4] rural Americans lack practical, affordable alternatives they can turn to when their electric rates rise. Electricity is not a luxury. It is vital for business and is an essential element of modern residential life.

At the same time, electric cooperatives, and the electric utility industry in general, are faced with disruptive and potentially fundamental changes as a result of rapidly evolving technologies and policy initiatives. Fostered by federal and state mandates and incentives and fueled by decreasing system costs, solar photovoltaic generation is one such technology whose growth presents new realities with financial and strategic implications for how cooperatives do business. Many in the electric utility industry are wrestling with the question of how to respond to what may become either a promising opportunity for future growth or a financial risk.

Electric cooperatives are embracing the challenge and leading the way. Co-ops have achieved national recognition for their early and widespread deployment of smart grid technologies, energy efficiency, and local distributed generation such as community-based solar. A 2012 report by the Federal Energy Regulatory Commission (FERC) noted that of the three utility sectors, cooperatives showed the largest penetration of advanced metering infrastructure.[5] With nearly 240 MW of solar capacity online or on the drawing board across the country, cooperatives are also at the forefront of the burgeoning solar industry. By empowering their member-owners to decide for themselves and fulfill their wants and needs, the cooperative business model allows for innovative solutions to

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[4] "About 83% of households with propane heating are located in rural areas that are typically beyond the reach of the natural gas distribution infrastructure." http://www.eia.gov/todayinenergy/detail.cfm?id=4070

[5] http://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf

balancing competing policy priorities and local conditions while ensuring reliable, affordable, and sustainable electric power.

Cooperatives are not only good partners and trusted resources for their member-owners; cooperatives are also good partners with the Department of Energy (DOE), having collaborated on a number of innovative and groundbreaking projects. Twenty-three electric cooperatives participated in NRECA's $68 million Smart Grid Demonstration Project (SGDP), half of which was funded by a DOE grant under the American Recovery and Reinvestment Act of 2009. After a vigorous review, DOE ranked NRECA's grant proposal highest among all utilities' submissions for its breadth, vision, and research value reflecting a multitude of technology settings. Indeed, the SGDP represents a watershed moment for electric cooperatives. It is the largest technology demonstration project ever undertaken by NRECA's research arm, the Cooperative Research Network (CRN), involving 23 electric cooperatives which serve 750,000 consumers in twelve states. The SGDP examined various smart grid technologies for their technical effectiveness, suitability to the cooperative business model, and return on investment. More than 250,000 pieces of smart grid equipment have been installed as a direct result of the project, and pilot tests of a dozen business applications enabled by smart grid technology have been completed. Research results from the project have and will continue to aid electric cooperatives' smart grid planning and decision making, and new strategic initiatives have been spawned in the areas of cybersecurity and economic cost/benefit modeling.

Another seminal NRECA and DOE partnership is the Solar Utility Network Deployment Acceleration project, or SUNDA, which is a multi-state 23 MW solar installation research project that seeks to identify and address barriers to photovoltaic deployment at cooperatives. Working with 14 co-ops that are planning from 250 kW to 5 MW of solar PV, NRECA is analyzing the business side of these deployments in order to develop a standardized "photovoltaic system package" consisting of engineering designs, business models, financing and insurance options, and optimized procurement that can reduce the cost of utility-scale solar projects. $3.6 million was provided by a grant from DOE's SunShot Initiative, which was matched by a $1.2 million cost share from NRECA, the National Rural Utility Cooperative Finance Corporation (CFC), Federated Rural Electric Insurance Exchange, PowerSecure International, Inc., and the 14 participating cooperatives.

The goal of the project is to explore how standardization can help bring down the "soft" costs – labor, procurement, supply chain, and other costs – of photovoltaic installations and also reduce uncertainty about the effects of these installations on a system. NRECA estimates that the standardized packages can reduce engineering design costs by 25%, procurement costs by 10%, and insurance costs by 25%.

These and other such projects are the fruit of the productive partnership enjoyed by NRECA and DOE. NRECA appreciates the opportunities offered by DOE, in terms of both the partnerships and the opportunities to offer comments such as in this Quadrennial Energy Review, and looks forward to continued collaboration with DOE going forward.

1. An "All of the Above" Generation Resource Portfolio Is Critical to Our National Energy Goals Set Out in the QER

1.1. An "All of the Above" Strategy Empowers Policymakers and Stakeholders to Respond to Future Unknowns – "No Regrets" Policy

NRECA has consistently advocated an "all of the above" vision of the grid of the future, one that enables the realization of different potential futures. An "all of the above" strategy empowers energy policymakers and stakeholders to respond to future uncertainties and unknowns; in contrast, a narrow vision limits flexibility in the face of those unknowns. Ten years ago, when gas prices averaged around $6 to $7/mcf, no one foresaw the "shale gale" and the resulting transformation of the electric generation fleet, with the accompanying new coordination and reliability challenges between electric and gas system operators. Today, no one can foresee what technological advances will occur in the next ten years, much less international developments. Given the broad, encompassing nature of our national energy goals as set out in the QER – Economic Competitiveness, Environmental Responsibility, and Energy Security – an all-of-the-above, no-regrets vision and strategy is critical to their realization.

All energy stakeholders, public as well as private, should recognize and build upon the value of the US electric grid as the foundation for the "all of the above" vision. As is often said, the US electric grid is the engineering wonder of the world. The grid enables our high standard of living. The grid's flexibility accommodates a changing generation mix, the impact of increasing variability from renewable resources, and the transition to a low-carbon environment. Going forward, the grid will be called upon to incorporate new technologies that support increased distributed energy resources and facilitate the deployment of cost-effective energy storage. But the demand for highly reliable and affordable electric service will remain constant, and will continue to be the primary responsibility of utilities and utility regulators for the foreseeable future.

The Department of Energy plays the most important role in ensuring that all of the changes coming our way, whether driven by technology developments, markets, or regulatory policy, are implemented in a way that enables everyone to benefit from the new energy future, and does not create inequitable or disproportionate outcomes. While pursuing a "no-regrets" policy, DOE and policymakers must also "do no harm." Given the largely rural nature of their service territories and typically low customer densities, electric co-ops are often early adaptors of electric system technologies when these are shown to be cost-effective and an overall benefit to their systems. However, state and federal policymakers must keep in mind the costs associated with regulatory and policy changes. Rural electric co-ops serve some of the poorest areas in the country, and are always conscious of cost impacts on end-use consumers, since all costs are paid by their consumer-members.

1.2. The Fuel Use Act had a Lasting Impact on Generation Investment Decisions, Grid Operations, and Reliability

1.2.1. The Government Should Not Pick Winners and Losers

Preserving an "all of the above" strategy for electric generation resources is a priority for the nation's electric cooperatives, but the challenges to maintaining a diverse portfolio are more formidable than ever. Low-priced natural gas in combination with state and federal environmental tax incentives that favor certain resources, and market dynamics that disfavor others, are driving the shift towards more natural gas and variable renewable resources while also driving out traditional baseload generation like coal and nuclear.

Much co-op-owned generation was built during the '70s, on the heels of the era of the Arab oil embargo, and utilized coal as a fuel source because there were no other options at the time. The Power Plant and Industrial Fuel Use Act (PIFUA or Fuel Use Act), passed in 1978, restricted the construction of power plants that use petroleum or natural gas as their primary fuels. The law was enacted to promote national energy security and to address concerns over natural gas availability by encouraging the use of coal and alternative fuels in new electric power plants. After the 1973 oil price shock, electric utilities saw a need to reduce reliance on petroleum. Most of the new utility plants built after 1975 were coal and nuclear facilities.[6]

[6] http://www.eia.gov/pub/oil_gas/petroleum/analysis_publications/chronology/petroleumchronology2000.htm

Although PIFUA was repealed in 1987, electric cooperative generation needs grew substantially during the time it was in effect. As a consequence, about 60% of cooperative total baseload electric generation was constructed under the Fuel Use Act and is coal based.

These coal units still have significant remaining useful life. While the best available control technology for pollution reduction was installed when these units were built, co-ops also have spent billions of dollars on pollution control upgrades over the course of the last several years to meet current EPA regulations. In some cases, the cost of these upgrades exceeded the original cost of the power plant. As a result, many co-ops have outstanding loans on many of these facilities and must dispatch these units to generate adequate revenue in order to repay the loans. In many cases units running even less that 10% below their operational norm on a continuing basis would be unable to generate enough revenue to service the outstanding debt on the unit. Running them less will lead to significant financial issues and a very high likelihood of creating stranded assets.

It should come as no surprise that under the EPA's Clean Power Plan, the co-ops find themselves squarely in between the proverbial rock and a hard place. As described above, Congress tried to help the industry through a prior fuel "crisis" with the Fuel Use Act, and effectively prohibited the use of natural gas as a generating fuel. Indeed, utilities were required to build the same coal plants that they are now being asked to shut down. If these facilities are forced to shut down in order to comply with the Clean Power Plan, the co-op's member-owners will still have to bear the costs of repaying the outstanding debt, while incurring additional cost for replacement power from the market, if it's even available, or the cost of new generation. Cooperative utilities are not-for-profit entities and do not have financial flexibility. All of these costs are passed on directly to co-op member-owners through their electricity bills.

1.3. Within the Context of the Changing Generation Resource Mix and Reliability, Merely Having Available Generation Capacity Does Not Equate to Having the Necessary Reliability Services

The changing resource mix also has implications for grid operations and reliability. As NERC has pointed out,[7] conventional units such as coal plants provide frequency support services as a function of their large spinning generators and governor control settings along with reactive support for voltage control. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available. But as the generation resource mix evolves, the reliability of the electric grid depends on the operating characteristics of the replacement resources, and the availability of those essential reliability services may be unduly dependent upon costs or market rules.

Merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the electric grid to have resources with the capability to provide sufficient amounts of these services and maintain system balance. More work is needed to ensure that markets offer incentives for or reward these necessary characteristics and flexibility.

1.4. Due to Regional Differences and the Need for Local Control, Regulatory and Market Structures Must Enable LSEs to Address Risks and Challenges

For the electric cooperative of today or indeed any utility with a traditional obligation to serve, the challenges of putting together a diverse and reasonably priced generation portfolio that will ensure reliable electric service at a reasonable rate are confounding. It's not just the environmental regulations that limit power supply options, although they play a huge role; it's not just the low price of natural gas that undercuts other resources and drives them from the market; it's not just the siting, permitting and other challenges that make hydropower, the nation's oldest carbon-free renewable resource, so difficult to develop; it's not just the increased development of behind-the-meter distribution energy resources, and the growth of policies and initiatives at both the state and

[7] http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

federal level that encourage increased DER and efficiency; and it's not just the continuing trend of low, flat or even negative load growth.

Not all of these things are present in every part of the country, though every part of the country is experiencing some of these things. Given this stone soup, it is essential that regulatory systems and market structures enable load-serving entities (LSEs) like cooperatives the flexibility to make local decisions that allow them to optimize a diverse portfolio of resources, including generation, transmission, distribution, and demand-side resources on behalf of their consumers in light of local conditions and their local consumers' preferences.

NRECA urges policies that support and reinforce the role of LSEs in performing that role. At the wholesale level, for example, NRECA has worked to preserve the ability of LSEs to serve load using the combination of self-owned, contracted-for, and market resources that best enables them to meet the long-term needs of their consumers with reliable, affordable and safe electric service.

Recently a group of utilities in PJM sent a letter to the PJM Board outlining their concerns with a PJM paper that argued that its markets are a more efficient means of attracting cost-effective new generation resources while minimizing risk to consumers.[8] The PJM utilities that signed the letter, including two G&T cooperatives, asserted that while there are risks and benefits associated with both competitive markets and a regulated environment, "many of the asserted benefits of the competitive markets have been achieved only due to legacy generation and transmission assets that were built under regulated constructs." Increasingly the concern of many market participants is that the short-term markets are best for producing the least expensive resource, but that this comes at the expense of fuel diversity, more expensive investments in long-lived assets, and even reliability as it fails to recognize the cost of necessary new transmission. "[I]t is naïve to think that a future driven by marginal resources through short-term capacity markets can adequately serve customers," while "the regulated paradigm inherently takes a long-term view of investments necessary to maintain proper fuel diversity, plant type diversity, transmission needs, and reliability, which results in reduced market volatility and consumer benefits."

[8] http://www.pjm.com/~/media/about-pjm/who-we-are/public-disclosures/20160519-coalition-pjm-board-letter.ashx

1.5. Reliability Must Be Balanced with Affordability Under Different Scenarios of Generation Mixes

NRECA shares the concern voiced by energy industry stakeholders across the spectrum that the timing of the shift in the generation mix is out of sync with the time needed to construct the necessary infrastructure; and that these circumstances in turn give rise to concerns about just and reasonable rates.

As FERC Commissioner Tony Clark testified to Congress last year:

> "I would emphasize that if a generation resource shift is compelled prior to necessary infrastructure completion, electric reliability could be a challenge, but regardless, **affordability will almost certainly suffer. Substantially higher energy costs have been the result everywhere this has occurred, and it will not be any different in this case if expanded infrastructure is not built in time to meet the generation mix changes required by the regulation."**

This problem, at least from an affordability standpoint, will be compounded in certain parts of the country, where there is a significant risk of infrastructure assets being stranded years before the end of their useful lives. This means consumers will be paying not just for the new infrastructure, but also for the previous investments in assets that are being retired to comply with EPA regulations."[9]

The QER has already highlighted the significant and accelerating transformation of the North American resource mix, with ongoing retirements of fossil-fired and nuclear capacity and concomitant growth in natural gas, wind, and solar resources. As other DOE initiatives such as the "Future of the Grid" and "Grid Modernization Initiative" have illuminated, the power system may change further as microgrids, smart networks, two-way power flows and other advanced technologies continue to be deployed.

Integration of these technologies will require a reliable and robust bulk electric system. Changes to electricity generation and energy-use patterns changes the way the system is operated. The key

[9] https://www.ferc.gov/CalendarFiles/20151201095914-Clark-12-01-2015.pdf (emphasis added).

question DOE needs to answer is, in the face of all these changes, what will be necessary to ensure continued reliable operation of the bulk power system, and to ensure just and reasonable rates?

Recommendations

1. Reliability and Affordability Must Remain Priorities Under Any Scenario.

Reliability and affordability are intertwined, bedrock principles. A consistent theme in the QER and in all such discussions regarding the evolving nature of the US electric system is how to maintain reliability in the face of the fundamental changes described in these comments: the changing generation resource mix; the integration of increasing amounts of intermittent resources, with the corresponding need for backup supplies and associated infrastructure; the integration of increasing amounts of distributed energy resources on the distribution side; the influx of new technologies that are changing system operations, and others. If we lived in a perfect world where money was no object, there would be no need for such discussions; but the reality is that while it may be possible to "keep the lights on" from a technical standpoint, the economics and the ultimate cost to the consumer in many cases could be prohibitive. **DOE can and must play the critical role in assuring that in all discussions around reliability, affordability remains a paramount priority.**

2. More Time is Needed to Construct and Put Into Service the Necessary Additional Infrastructure to Support the Transformation of Generation Portfolios.

The EPA's proposed Clean Power Plan (CPP) and the Mercury and Air Toxics Standards (MATS) rule will accelerate the comprehensive shift that is already underway in the United States electric generation resource mix. The power industry's reliance on natural gas for generation will increase significantly due to the low cost of natural gas, environmental regulations, coal plant retirements, and the intermittent nature of wind and solar generation which requires gas for back-up. Between 2015 and 2019, retirements of coal-fired generation will outpace the installation of new natural gas-fired generation capacity.

However, the early retirement of coal units resulting from EPA regulations may create reliability risk if operationally flexible natural gas infrastructure cannot be constructed prior to the early plant retirements or conversions to natural gas. Under the EPA's proposed carbon reduction deadlines, there is not sufficient time to adequately plan, design, and build new generation, transmission, and natural gas infrastructure required to maintain reliability.

Lead times to construct new facilities are longer than ever, and continue to face siting and construction challenges. According to the Energy Information Administration (EIA), an interstate natural gas construction project will take approximately three years from the time it is first announced until the new pipeline is placed in service and large, complex projects can take even longer to complete. The timeline to identify a generation need, receive regulatory approval, and place the new generation in service can take between six and eight years. In addition, NERC has estimated that it can take up to 15 years to build a new 500 kV electric transmission line. As recently reported in Politico in the context of cross-border high-voltage transmission: [10]

> President Barack Obama, Canadian Prime Minister Justin Trudeau and Mexican President Enrique Peña Nieto on Wednesday made official a commitment to generate half of their power from clean energy by 2025. To get there, they agreed they'd need, among other initiatives, 5,000 MW of cross-border transmission lines, presumably to carry wind, solar, and hydropower across national borders. "There may be some wonderful hydroelectric power that we'd like to get to the United States. The question is, are there enough transmission facilities for us to be able to buy at a competitive price," Obama said at a press conference in Ottawa. "Just as we develop wind energy, we have to build an infrastructure to get wind produced in South Dakota down to Chicago."
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> The long, slow slog of high-voltage transmission: **Building high-voltage transmission lines across hundreds of miles can take as long as a decade**. That South Dakota-to-Chicago project Obama references was almost certainly the Rock Island Clean Line, which is facing protests from local landowners over developers' attempts to use eminent domain. Recent cross-border projects, like Northern Pass in New Hampshire (intended to carry Quebec hydro into New England), the New England Clean Energy Link (also to bring Quebec hydro, but through Vermont), and the Great Northern transmission line (to bring Manitoba Hydro to Minnesota) have all been bogged down in environmental reviews or state and local objections.

[10] Insert cite to Politico, Morning Energy, June 30, 2016 (emphasis added).

3. DOE's Efforts to Streamline and Simplify Needed Infrastructure Planning and Development are Appreciated and Should Continue.

In the first QER report issued in April 2015, DOE highlighted some important findings and recommendations regarding the challenges facing infrastructure development:

> "The trends affecting TS&D infrastructure discussed in this report – including major increases in oil and gas production, expanding production of renewable energy, changing requirements for what is expected of energy infrastructure, climate change, and steps to maintain electricity grid – are shaping and driving demand for new TS&D infrastructure. **Over the last decade, there has been a growing awareness of the gap between the times typically needed to permit new generation and production sources of energy and the much longer times needed for TS&D infrastructure. This discrepancy in permitting time frames affects everything from transmission planning to utility procurement and project finance decisions – making it more challenging to plan, site, permit, finance, and construct energy infrastructure projects.** Given these challenges, it is essential to promote more timely permitting decisions while protecting our Nation's environmental, historic, and cultural resources."[11]

NRECA appreciates DOE's attention in QER 1.1 to the need for additional electric and gas transmission infrastructure, and the siting and permitting obstacles that delay and often prevent it from being built. NRECA members testified to these critical needs and challenges during both QER 1.1 and 1.2 and highlighted it in our comments and recommendations. Like many, we were encouraged by last year's enactment into law of the "Fixing America's Surface Transportation (FAST) Act."[12] Here, we reiterate our support for the QER 1.1 recommendations to: 1) allocate the necessary resources to key Federal agencies involved in the siting permitting, and review of infrastructure projects; and 2) adopt proposals to authorize recovery of costs for review of project applications.

Siting and permitting challenges also impede the effective development of the nation's hydropower potential. The U.S. hydropower fleet has been providing clean, reliable, and carbon-free power for more than a hundred years, and pumped hydro storage is still the only effectively available form of utility-scale electrical energy storage in the country. Simply put, the nation's carbon reduction goals

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11 http://www.energy.gov/sites/prod/files/2015/08/f25/QER%20Summary%20for%20Policymakers%20April%202015.pdf (emphasis added).

12 Fixing America's Surface Transportation (FAST) Act, Pub. L. No. 114--- 94.

cannot be achieved without hydropower. DOE has identified nearly 77 GW of potential new sources of clean, renewable hydropower at currently undeveloped dams, rivers and streams of the U.S.[13] DOE should continue to focus efforts on streamlining the permitting and licensing for hydro projects.

4. DOE Should Revisit the Conclusions in its 2015 Report on "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector."

DOE's 2015 report on natural gas infrastructure suggested that there is little need for new pipeline infrastructure in response to higher gas demand resulting from increased use of gas for electric generation.[14] Most observers on the ground, including many NRECA members who are increasingly relying upon natural gas –fired generation, dispute this premise.[15] Former FERC Commissioner Phil Moeller frequently highlighted the concern about whether there would be sufficient pipeline capacity to support the increase in natural gas-fired electric generation.[16] As DOE itself noted, adequate natural gas infrastructure is a key component of electric system reliability in many regions.

During a FERC meeting in February 2015 when the report was presented, the conclusions in this report were vigorously disputed by FERC Commissioners LaFleur, Clark, and then-Commissioner Phil Moeller.[17] The FERC Commissioners pointed out that the report did not reflect regional and local specifics; did not address peak demand situations; and did not address siting challenges. For example, as Commissioner Clark noted, even if there are now sources of gas supply like the Marcellus that are closer to major demand centers, it's still the most difficult part of the country to build infrastructure in, even if the need is for a shorter length of pipe. The New England ISO has

[13] http://www.energy.gov/eere/water/downloads/2014-hydropower-market-report

[14] http://www.ferc.gov/CalendarFiles/20150219081732-DOE Report Natural Gas Infrastructure V_02-02.pdf

[15] https://www.washingtonpost.com/news/energy-environment/wp/2015/02/09/a-new-report-just-shot-down-a-key-argument-against-president-obamas-climate-plans/

[16] https://www.ferc.gov/CalendarFiles/20140729091755-Moeller-07-29-2014.pdf

[17] http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=7678&CalType=%20&CalendarID=116&Date=02/19/2015&View=Listview

documented the need for additional gas pipeline infrastructure in that region.[18] DOE itself noted that more than 3.2 Bcf/d of additional natural gas pipeline capacity will be needed to serve the projected demand in the Northeast between now and 2030.

NRECA is raising this point because DOE reports have influence. Building the infrastructure necessary to support our increased reliance upon natural gas supply for electric generation requires multiple siting and permitting processes all over the country, at every level of government. As DOE itself has recognized, these processes have become exceedingly more complex; and in that context, a report such as this can easily be misconstrued. NRECA urges DOE to reaffirm that the need for a stable, reliable and expanded gas transportation system goes hand in hand with our increased reliance upon natural gas for electric generation.

[18] http://www.iso-ne.com/static-assets/documents/2015/03/icf_isone_van_welie.pdf

2. The End Result of Any Market Rule Changes Must Continue to Produce Just and Reasonable Rates for Consumers

Electric cooperatives operate under and are active participants in a variety of wholesale market structures throughout the United States.[19] The goal of each and every co-op is the delivery of reliable, affordable, and sustainable long-term electric power to its member owners. This requires resources adequate to meet both current and future consumer demand, including sufficient generating capacity, fuel diversity and appropriate fuel security to ensure reliability.

In terms of market design (and power supply), a one-size-fits-all model is the wrong approach. Different market models work better for certain regions than others. There is one key, however. Wholesale markets should be designed to enable and support efforts to manage a portfolio of resources on behalf of consumers that includes generation, transmission, distribution and DER. Regulators and market operators should focus on ensuring that the wholesale markets and wholesale regulatory structures enhance wholesale customers' ability to obtain, deliver, and manage the portfolios of resources they need to serve their retail consumers more affordably, more reliably, and with less discrimination by other market participants.

In terms of price formation (and cost allocation), the goal in organized wholesale electricity markets should be, in the short-term, to assure the efficient dispatch of resources to provide energy and ancillary services at the least cost feasible to consumers. In the long-term, the goal should be to attract and enable investment in an efficient and diverse portfolio of resources that meet a wide range of operational, price, reliability, environmental, economic development, risk management and other goals established by state and local regulators, cooperative boards and wholesale power customers. Regional Transmission Organization (RTO) and Independent System Operator (ISO) market rules governing energy and ancillary services market price formation methods and protocols, and RTO/ISO rules governing price formation in certain organized wholesale capacity markets, have fallen short of fully achieving either objective. DOE should continue to promote efficiency gains for the benefit of consumers and continued protection against the exercise of market power.

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[19] For example, co-ops in New England operate within Independent System Operator (ISO)-New England, a Regional Transmission Organizations (RTO) that traces its roots to the New England Power Pool (NEPOOL), one of the oldest power pools in the U.S. In contrast, co-ops operating in the southeast and WECC, exclusive of the California ISO, operate in bilateral markets.

Pricing proposals should always ensure that the interactive effects of price reforms in capacity and energy/ancillary services markets together produce prices for consumers that are just and reasonable, keeping in mind that long-term bilateral contracts and self-supply options may better address long-term investment and diversity needs than reforms of short-term energy, ancillary services and capacity prices. Moreover, individual energy and capacity market price formation rules may create overlapping incentives and may even have unintended, conflicting consequences.

The bottom line is that the end result of any market rule changes must continue to produce just and reasonable rates for consumers. Existing wholesale market rules governing in the RTO/ISO energy, ancillary services and capacity markets are intricately intertwined with one another and with the rules governing market power mitigation. Changes to such rules should always include careful review of how the rules interact with the overall market design; and reforms should always seek to achieve efficient dispatch in the short term, benefits in production-cost savings for consumers, incentives for investment in an appropriately diverse mix of resources in the long term, and continued strong protection against the exercise of market power.

2.1. Electric Cooperatives Must Have Efficient and Unfettered Access to Bilateral Markets so that they can Manage, Optimize and Integrate a Resource Portfolio that Controls Cost and Risk for their Consumers

There are fundamentally two types of wholesale generation markets in the U.S. – centralized and bilateral markets, though the two overlap and co-exist in centralized-market regions. The centralized RTO/ISO model, where suppliers compete in short-term markets to balance market requirements, is the norm in the Northeast, Mid-Atlantic, much of the Midwest, Texas, and California. Bilateral transactions also exist within centralized markets. The bilateral model, which is marked more by bilateral arrangements ranging from standardized contract packages to customized structured transactions as a component of the traditionally regulated model, is prevalent in the Southeast, most of the Southwest, parts of the Midwest and the West, excluding California. Development and evolution of centralized markets over the past 25 years occurred on a regional basis prompted in large part by seminal legal and regulatory changes (EPACT 1992, FERC Orders 888, 889, and 2000, and expansion of retail choice), and was in some cases facilitated by the presence of a functioning power pool. Some of the centralized markets have capacity markets designed to help compensate for longer term generation investments. These markets tend to be quite controversial and usually overlap primarily with regions where the states also have restructured retail markets and some form of retail competition for consumers. Many of these markets have functional issues that drive constant change to the detailed market rules, but the fundamental concept essentially remains the same.

In those service territories with both centralized wholesale markets and retail competition, the distinction between wholesale and retail electric markets is now blurring. Some competitive retail suppliers are passing wholesale prices directly through to retail consumers. Some competitive aggregators are bidding retail consumers' demand response directly into the wholesale markets. Some larger consumers are also looking to increase their ability to participate in the wholesale markets both as consumers and as providers of capacity, generation, and ancillary services.

By contrast, co-ops operating in both bilateral and centralized market regions act as an intermediary between retail consumers and the wholesale markets. Co-ops act as wholesale customers in both market structures, purchasing resources as part of the portfolios they manage for the benefit of their consumers. Co-ops also act as suppliers in both wholesale market structures, selling resources into the markets where doing so allows them to manage costs for their consumers. Co-ops also use distributive energy resources (DER) to reduce their risk exposure when acting as consumers in the wholesale markets or as a resource they can bid into the wholesale markets when it is to the advantage of all their consumers for them to act as suppliers.

The wholesale markets are a critical element of many co-op's resource portfolio. For the foreseeable future, centralized generation resources will be a significant element of those portfolios, and the markets provide co-ops with an important option for acquiring rights to generation and capacity without the obligation to take on the cost and risk of building their own generation. The centralized markets, where they are available, can offer an efficient source of short-term resources. Bilateral markets permit co-ops to put together a diverse generation portfolio with long-, medium-, and short-term contracts for a wide variety of resources with different fuel sources, different emissions characteristics, different operating characteristics, different locations, and different risk profiles. Thus, in the future, co-ops must have efficient and unfettered access to those bilateral markets so that they can manage, optimize and integrate a resource portfolio that controls cost and risk for their consumers.

Similarly, co-ops must be permitted to continue to act as the intermediary between their consumers and the wholesale markets. DER is a significant part of many co-op's integrated resource portfolios. If those DER resources are disaggregated and permitted to participate directly in wholesale markets for their own benefit, it can severely undermine the co-op's ability to manage cost and risks for their entire consumer base. Cherry picking can undermine the economics of a co-op's demand response programs, reducing the total level of demand response available in the market, reducing a co-op's incentives to invest in DER and the infrastructure required to enable it, and effectively removing DER from a co-op's integrated portfolio. It can also undermine reliability by increasing the unpredictability of load on a co-op's systems. It was for these reasons that FERC permitted appropriate regulatory authorities – state PUCs, municipal governments, and cooperative boards – to decide whether to allow aggregators to bypass utility DR programs and bid retail demand response directly into the wholesale markets.

Co-ops should continue to have the right to act as the intermediary between retail consumers and the wholesale markets. Co-ops should be able to develop the demand response, efficiency, and customer-generation programs that best integrate within an optimum resource portfolio and to bring those resources into the wholesale market in the manner that best meets their consumers' needs. That will allow them to promote DER, manage market risks across their whole resource portfolio, and ultimately provide their members with safe, reliable, affordable, and environmentally sustainable power at a reasonably predictable price over the long term.

Thus, by preserving electric cooperatives' access to wholesale markets, right to serve as market intermediary for consumers, and flexibility to do so in the manner that best meets local needs in light of individual co-ops circumstances, wholesale market design should preserve all of the benefits that the co-op business model offers consumers. It can ensure that co-ops have the ability and incentive to meet consumers' changing needs, to integrate new technologies and services into their resource portfolios, and to bring the benefit of those new technologies into the wholesale market as a market participant and market intermediary.

2.2. Capacity Markets Should Serve the Needs of Electric Cooperatives and Electricity Consumers

2.2.1. Electric Cooperatives Have a Number of Options in Acquiring Capacity Resources

Every load-serving entity (LSE) on the electric grid, including electric cooperatives, must keep their resources in balance with their loads at all times, lest the imbalance destabilize the grid and cause an outage not only for their own customers, but also for all other customers within the region. However, the grid is subject to unpredictable events that can cause demand to spike or that can cause the loss of major transmission or generation resources with limited or no notice. Because of this unpredictability, regulators and RTOs require the grid to have access to 9-20% more capacity – the capability of generation or other resources to meet demand – than anticipated peak demand to meet any contingencies that may arise.

LSEs, including electric cooperatives, have a number of options for acquiring capacity resources:

- LSEs can own some of their capacity, by owning all or part of a generating unit, or developing demand-side resources such as battery storage or demand-side management.
- LSEs can contract in the bilateral market, granting LSEs a right to capacity from all or a share of a single plant, a share of a group of plants, or a "slice" of another LSE's entire resource portfolio. Contracts will also define the conditions under which LSEs may have a right to delivery of energy from the capacity resource, and the price that the LSE will be required to pay for that energy.
- LSEs can also participate in a reserve sharing agreement with one or more other LSEs so they can share the cost and reduce the total level of reserves required to operate.
- In MISO, LSEs have the option to participate in a voluntary centralized capacity auction, which allows LSEs to bid for planning resources from market participants with excess capacity. The auction is conducted two months before MISO's Planning Year, and held for resources for a single year. As the auction is voluntary, no LSE is required to bid their resources into the auction or to have their resources clear that auction to be permitted to use those resources to meet their resource adequacy obligations.

- In the regions served by ISO-NE, NYISO, and PJM, there are mandatory centralized capacity markets. All three operate mandatory capacity auctions that require all capacity to be bid into and purchased out of those auctions for that capacity to count towards meeting an LSE's resource adequacy obligations within their respective RTOs.

2.2.2. Buyer-Side Market Power Mitigation Mechanisms Harm Consumers

The capacity markets in the eastern RTOs were designed to supplement the same bilateral markets and self-build options available to LSEs elsewhere in the country. Unfortunately, rather than designing those markets to work in parallel with the bilateral markets and self-build options, the RTOs and FERC have begun treating the centralized capacity markets as their primary tool for encouraging investment and ensuring reliability. In order to ensure that those centralized capacity markets can clear at what the RTOs consider to be the "right" price to accomplish those goals, all three of the eastern RTOs have adopted buyer-side market power mitigation mechanisms aimed at preventing LSEs, including electric cooperatives, from acquiring "uneconomic" capacity resources that will "artificially" suppress clearing prices in the centralized capacity constructs.

Unfortunately, no matter how much the centralized capacity markets may be adjusted through litigation, buyer-side market power mitigation mechanisms do not seem to serve the goals of "just and reasonable" rates for consumers. Moreover, buyer-side market power mitigation mechanisms are at best poorly rooted in either law or economic theory. Not only is it impossible for those buyer-side market power mitigation mechanisms to accomplish the goals for which they were adopted, they penalize pro-competitive economic behavior, and actually undermine reliability.

In order to ensure reliability, provide for efficient markets, and enable states to promote important policy goals, the value of all capacity investment options must be recognized, the buyer-side market power mitigation mechanisms in the eastern RTOs should be eliminated, and the obligation and freedom to acquire adequate capacity resources to LSEs and the states must be returned. It is necessary to look beyond the centralized capacity markets and include bilateral capacity markets and LSEs' – including electric cooperatives' – self-build options in the solution and the eastern RTOs' centralized capacity constructs must be adjusted so that all three resource options can work effectively side-by-side. To make that happen, buyer-side market power mitigation should be abandoned and states and LSEs within centralized market regions must be provided both the obligation and the freedom to manage their own resource decisions.

2.2.3. Capacity Markets Should Work in Conjunction With Bilateral Markets and Self-Supply

Though not every region may benefit, there is nothing fundamentally wrong with the idea of centralized capacity markets, so long as they operate neatly in conjunction with, and not in conflict with, bilateral markets and LSEs' self-build options. As with the voluntary centralized capacity market in the Midwest (specifically, MISO), they can be an efficient supplemental tool for enabling those who are long in capacity and those who are short to transact in the short term. To the extent there is excess capacity available, centralized capacity markets also permit both generators and LSEs to diversify their portfolios, adding short term sales and purchases to a broader portfolio that also includes long- and medium-term capacity transactions.

However, the mandatory centralized capacity constructs in the east (ISO-NE, NYISO, and PJM) took a wrong turn when they began depriving LSEs of guaranteed clearing for self-supply and state mandated resources. And, they took a wrong turn when the RTOs themselves (with FERC's approval) concluded that the centralized capacity constructs needed to, or even could, arrive at a "right" price that could, if properly engineered through layers of mitigation and market rules, provide efficient price signals that would induce private investors to make enough investment in new and existing resources to ensure resource adequacy.

Further, the continuous tinkering with capacity market design in order to chase resource adequacy is unnecessary where LSEs such as electric cooperatives already have the obligation to meet resource adequacy requirements and are assured that they may use their own resources for that purpose.

Centralized capacity markets should be considered a supplement for, and not a replacement or substitute, for bilateral capacity markets and self-supply. In reimagining the markets this way, the obligation for resource adequacy needs to be put back where it belongs – on LSEs and states – and give them both the freedom and incentive to meet that obligation in the manner that best meets their needs. In so doing, this would solve one of the fundamental concerns that the independent power producers have expressed with the bilateral markets – too few counterparties willing to enter into long-term contracts. If the burden can be put back on restructured states and competitive LSEs to ensure long-term reliability, they can recreate that natural market for long-term transactions in the bilateral market.

2.3. Centralized Capacity Markets Optimize Only for Short-Term Price and Often Struggle to Reflect Other Preferences and Needs

2.3.1. Centralized Capacity Markets Cannot Meet All of the Needs of Load-Serving Entities

Centralized capacity markets can be a valuable option for LSEs on the margins. In fact, voluntary capacity auctions afford LSEs with an additional mechanism to procure needed capacity and increase transparency in the procurement of capacity.

Centralized capacity markets cannot, however, meet all of an LSE's needs. Centralized markets are to bilateral markets as commodity markets, such as NYMEX, are to over-the-counter markets. Centralized markets manage standardized transactions for fungible products, such as wheat, pork bellies, or oil at a particular hub. In the centralized capacity markets, buyers can acquire limited additional capacity resources to meet their RTO resource adequacy obligation, but they are not able to engage in customized transactions or acquire an actual slice of a generator capable of meeting multiple needs as they can in the bilateral markets. Moreover, as the Supreme Court has acknowledged, "[m]arkets are not perfect, and one of the reasons that parties enter into wholesale power contracts is precisely to hedge against the volatility that market imperfections produce."[20]

Centralized capacity markets generally optimize only for short-term price, and, therefore, cannot replace the role of states and LSEs in optimizing the resource portfolio. Because they optimize only for short-term price, centralized markets often struggle to reflect other preferences, such as the

[20] *Morgan Stanley Capital Grp. Inc. v. Public Util. District No. 1*, 554 U.S. 527, 547 (2008).

range of policy goals considered by policy makers and the different manner in which those policy makers prioritize those goals.

Self-build options and the bilateral energy and capacity markets provide the opportunity for LSEs to obtain over short, medium and long terms those specific resources that they, their consumers, and/or their regulators conclude best meet their needs in light of a range of policy goals, including: low price, reliability, fuel diversity, environmental performance, appetite for risk, economic development, and others.

2.3.2. Load-Serving Entities' Ability to Transact in Bilateral Markets is Being Undermined by Capacity Markets

Unfortunately, the trend in the centralized capacity constructs has been to undermine LSEs' ability to transact in the bilateral markets and to build their own resources to obtain the resources they need to meet their various business and regulatory obligations. Rather, the markets aggressively discourage such investments if those investments do not beat the costs of fungible capacity resources bid into the centralized constructs without consideration of those resources' environmental value, technological value, or reliability value more than three years out. Henry Ford once said, customers can have a car painted any color they want, so long as it is black. Similarly, the newer construct rules now say that LSEs can invest in any resource they want, so long as it is the low cost resource in the auction year as calculated by the RTO, regardless of the actual value of the resource to the consumer.

If the LSEs want something other than what the incumbent suppliers are offering, they have to take the risk of paying twice for capacity: once for the resource that meets their business, operational, and regulatory needs and again for the resource the RTO thinks they should have purchased based on a myopic view of value. Those changes have threatened to block LSEs', including electric cooperatives', efforts to manage their business and operational risks, and by creating barriers to entry, have both driven up market prices and undermined reliability.

2.3.3. Capacity Markets Do Not Incent New Generation Investment

The centralized capacity constructs have neither ensured the independent power producers (IPPs) a consistent return on their investments nor led to the development of significant new IPP generation capacity in the eastern RTOs. As a recent American Public Power Association (APPA) study has shown[21], most capacity in those regions is still built pursuant to bilateral contracts and self-build efforts, and not by IPPs relying solely on RTO market revenues.

APPA's study found that nearly all generation in the United States has been built by LSEs or in connection with long-term power-purchase agreements (PPAs) with LSEs. Their analysis found that only 2.4% of new capacity had been built on spec, for sale into the markets, and that number includes new facilities for which no information could be found about contracts. In fact, APPA found that only 6% of all capacity built in 2013 was even built within the footprint of the RTOs that have centralized mandatory capacity constructs (even though those states hold a little over one quarter of the customers). Two thirds of the 2013 capacity APPA reviewed was built with PPAs and 31.6% was constructed under the ownership of a utility. 2% was constructed directly by the end use customer. Of the 2.4% to be sold into the markets, nearly all received some form of non-market funding such as grants under the American Recovery and Reinvestment Act. That left only 0.1% built solely for sale into the RTO markets without any other source of income.

There is a good reason that investors are not building solely in response to RTO market incentives. Investors require the certainty of native load or long-term PPAs. FERC understood this at one point, stating: "we are mindful of the comments made to us by representatives of the financial community, that dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure. A clear preference for long-term contracts and/or reliable revenue streams was stated."[22]

There is also a good reason why investors want long-term contracts before investing. Although shortages in the markets drive up prices, signaling the need for new capacity, actually building capacity in response to that price signal automatically destroys the price signal by increasing supply

[21] http://www.publicpower.org/files/PDFs/Power_Plants_Not_Built_on_Spec_2014.pdf

[22] *PJM Interconnection, L.L.C.*, 115 F.E.R.C. ¶ 61,079 at P 68 & n.78.

and driving down price. Thus, the only entities in the market that have an incentive to build generation or to contract to have it built in response to price signals are those who want the price to go down – LSEs and state regulators. The market design should do all it can, therefore, to enable those investments. However, the mandatory market increases the risks to any LSE that responds to the price signal through self-supply – including the risk of having to pay twice for capacity if their mitigated bids do not clear the market – making it less likely that those entities will build much new generation.

Indeed, the organized markets are also a poor choice for ensuring adequate generation capacity because they treat all capacity as fungible. That simplicity makes them good tools for the efficient transfer of capacity in the short term between those who are long and those who are short. This is what the voluntary MISO centralized capacity market achieves.

On the other hand, centralized capacity constructs' treatment of all capacity as fungible makes them a very ineffective tool for driving investment in the right resources to meet the industry's broader need for such values as portfolio diversity, fuel diversity, temporal diversity, environmental compliance, and operational characteristics such as ramping capability, black-start capability, and inertia. Because many of the values that generation provide cannot be monetized in the centralized markets the way that they can be in the bilateral market, it is irrational to assume that "a purely private new entrant should be able to recover 100% of its costs from [centralized] market revenues."[23]

A "well-designed resource adequacy requirement supports competitive markets if it allows suppliers to compete to provide infrastructure and buyers to choose the infrastructure with the best combination of features such as cost, reliability, environmental effects, and service life."[24] In fact, "[c]entral to the Standard Market Design concept is its reliance on bilateral contracts entered into between buyers and sellers. The resource adequacy requirement strongly encourages such long-term contracts. The short-term spot markets set out below are intended to compliment bilateral procurement."[25]

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[23] *Consolidated Edison Co. of N.Y., Inc. v. N.Y. Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,139 at P 64 (2015).

[24] Notice of Proposed Rulemaking, *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, F.E.R.C. STATS. & REGS. ¶ 32,563 at P 461 (2002), 67 Fed. Reg. 55,542 (2002) (codified at 18 C.F.R. pt. 35)

[25] *Id.*

2.3.4. Bilateral and Centralized Capacity Markets Should Complement Each Other

The benefits of bilateral and centralized markets may best be differentiated on a temporal scale. The centralized markets are very good at real-time, day-ahead commitment, and other short time frames. The centralized markets have enhanced the reliability and efficiency of the day-ahead commitment process and real-time dispatch of the electric system. They have helped to ensure that the transmission system is operated on a non-discriminatory basis.

The bilateral markets, on the other hand, have the capability of addressing LSEs' needs beyond the real-time and day-ahead commitment time frames. Generation and transmission resources can take 2-15 years to build and can remain in service for 40+ years. They can require tens-of-millions to billions of dollars to build. They can offer different LSEs and other parties multiple benefit streams to meet a wide variety of needs, but they can also pose a significant risk for LSEs, their investors, and their consumers. In a way that centralized capacity constructs cannot, the bilateral markets permit investors and LSEs to customize their transactions to monetize each of the different potential value streams, to manage risk amongst each other, and to provide long-term secure income streams to support the investments.

Consumers and regulators in restructured states have just as much interest as those in traditionally regulated states in safety, reliability, and affordability. And, they have just as much interest in clean and efficient power. That requires investment in long-term resources. And, as discussed above, investors in those resources want long-term financial commitments. There is no free ride in economics. If the customers of competitive LSEs in restructured states want to receive safe and reliable power at stable prices but pay no more than the commodity price of electricity, the costs of that service must go somewhere.

Costs should be imposed on those who cause them. LSEs that have acquired state-mandated or self-supplied resources are not imposing any costs on the RTO or their neighbors. They are meeting their own needs and their consumers are responsible for covering those costs.

On the other hand, to the extent that state policy has undermined wholesale markets by undermining the long-term revenue required to support bilateral contracting, incentives for states should be allowed in order to address that error. One option would be to let those competitive retail suppliers and their consumers see the volatility and risk of shortages their short-term business strategy may cause. If competitive LSEs do not acquire enough resources and that causes resource scarcity and drives up prices for capacity and energy, it is not unjust and unreasonable to expect just those competitive LSEs and their consumers to bear that cost. The centralized capacity constructs are already designed to have this impact. Those who meet their resource adequacy obligation largely through owned resources and long-term bilateral contracts would have little exposure to volatility in the short-term capacity constructs, whereas those who rely more heavily on those constructs would be much more exposed to high prices arising from shortages.

Another option employed in most regions of the country is for the RTO or other regulating body to impose a fine or a fee on those LSEs that fail to bring sufficient resources to market. If that payment is high enough, it should provide sufficient incentives for those LSEs to acquire reliable capacity resources.

2.4. FERC Does Not Set Wholesale Rates

The Supreme Court's decision in *Hughes v. Talen Energy Marketing*[26] does not completely resolve the thorny jurisdictional issues arising in the power sector that could not have been anticipated at the time the 1935 Federal Power Act was written. NRECA believes the decision is based on the mistaken premise that FERC, rather than the process of contracting between participants in wholesale markets, "sets" wholesale power rates. Unfortunately, at least in the short term, the decision could impede the orderly development of needed electric infrastructure at reasonable cost by disabling important functions reserved to state regulators under the Federal Power Act concerning the development of electric generation resources. The misapplication of preemption principles in the decision affords incumbent merchant generators insulation from the force of possible competitive entry.

[26] 136 S.Ct. 1288 (2016)

The decision is at odds with previous Supreme Court decisions concerning both field and conflict preemption in federal regulatory regimes, such as the FPA, that explicitly reserve roles for state regulatory authority. Nothing in the FPA suggests that FERC's authorization of a centralized capacity auction displaces the ability of utilities, both non-profit and investor-owned, to purchase capacity and related products and services where they choose. Rates are set by public utilities, not by FERC, which only reviews rates set up by public utilities to ensure that those rates meet the FPA's "just and reasonable" standard.

It has long been understood that:

> "Sections 205 and 206(a) [of the FPA] 'are simply parts of a single statutory scheme under which all rates are established initially by the (utilities), by contract or otherwise, and all rates are subject to being modified by the Commission upon a finding that they are unlawful. The Act merely defines the review powers of the Commission and imposes such duties on (utilities) as are necessary to effectuate those powers; it purports neither to grant nor to define the initial rate-setting powers of (electric utilities).[27]

FERC itself has long held that centralized capacity auctions are intended to operate in tandem with robust bilateral markets, precisely because it is the bilateral markets that actually support the addition of needed energy infrastructure with long-term and predictable contract revenues. The Maryland Commission order challenged in the proceeding simply created a way for Maryland's retail electric utilities to respond to price signals provided by PJM's centralized capacity auction and by the bilateral market. In holding that the contracts into which the Maryland Commission required Maryland's retail electric utilities to enter were preempted by FERC's approval of the auction mechanisms in PJM's centralized capacity auction, the Court of Appeals conflated two distinct rate-setting processes, each of which has a distinct and well-recognized role in the relevant wholesale electric power market.

The nature of power markets has long been one in which the matter of determining jurisdiction is more complicated than a plain reading of the statute would allow. Supreme Court decisions are necessarily a reflection of the particular facts of the case, and unless Congress acts, the Court will

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[27] *Papago Tribal Utilities Authority v. FERC*, 610 F.2d 914, 924 (D.C. Cir. 1980), *quoting United Gas Pipeline Co. v. Mobile Gas Service Co., supra,* 350 U.S. at 341.

not resolve the underlying issues: states are testing the boundaries of their jurisdictions because federal regulators have so far been unsuccessful in designing market mechanisms adequate to incentivize generation to the extent states desire. One thing is certain: The *Hughes* decision[28] highlights the obstacles to state efforts to support continued operation of existing generating units and construction of new plants. Over the next few years, sparring over this issue could intensify. FERC, state regulators, the U.S. Environmental Protection Agency (EPA) and the courts are all likely to be involved.

In the wake of *Hughes*, generation owners and state regulators will be required to explore new mechanisms to support continued operation of existing coal and nuclear generating units and to achieve long-term resource planning goals without running afoul of FERC. The success of these efforts could have a major impact on market value of new and existing generating units, decisions regarding whether to retire marginally economic coal and nuclear plants, the attractiveness of building new generation and the frequency and severity of future price spikes.

Recommendations

As not-for-profit private businesses and stewards for their member-owners, it is essential for electric cooperatives to be able to invest in those generation resources that they believe best meet their needs for energy, capacity, ancillary services, risk management, environmental stewardship, regulatory compliance, and other business obligations, in light of their broader resource portfolio.

1. Co-ops Should Continue to Have the Right to Act as the Intermediary Between Retail Consumers and the Wholesale Markets.

It is imperative to the cooperative business model that coops be the intermediary between their consumers and the wholesale markets. Co-ops should be able to develop the demand response,

[28] There is similar, on-going battle in Ohio, as well. On April 27th, FERC blocked implementation of two Purchase Power Agreements (PPAs) approved by the Ohio Public Utilities Commission (Ohio PUC). The PPAs, involving FirstEnergy Corporation (FirstEnergy) and American Electric Power Company Inc. (AEP) were intended to support continued operation of more than 6,000 MW of existing coal and nuclear generation in Ohio. *Electric Power Supply Association, et al. v. FirstEnergy Solutions Corporation, et al.,* 155 FERC ¶ 61,101 at P 57 (2016).

efficiency, and customer-generation programs that best integrate within an optimum resource portfolio and to bring those resources into the wholesale market in the manner that best meets their consumers' needs. That will allow them to promote DER, manage market risks across their whole resource portfolio, and ultimately provide their members with safe, reliable, affordable, and environmentally sustainable power at a reasonably predictable price over the long term.

2. Bilateral Markets Exist, and Those Markets Serve a Valuable Purpose and Should Be Supported.

Bilateral and centralized markets both serve uniquely complementary purposes, with the former allowing for meaningful customized investment in generation and transmission resources over many years and the later enhancing reliability, efficiency and access in real-time and day-ahead market time frames. Both markets must be preserved and supported to ensure that those responsible for causing costs in both the near- and long-term pay for them accordingly. Bilateral markets create an appropriate sphere for long-term investment that is built upon certainty of native load or long-term PPAs. Centralized market treatment of all capacity as fungible ignores numerous core industry objectives; however, bilateral markets allow for investment based on goals such as environmental compliance, portfolio and temporal diversity, and operational desires.

3. Long-Term Planning Must Be Incentivized in the Interests of Reliability.

Capacity markets alone do not incent new generation, leading to longer-term resource adequacy and reliability issues. To ensure reliable generation and transmission resources, an all-of-the-above emphasis on bilateral and capacity markets, along with self-build options, will allow for the proper and specific resources to be built that meet consumer needs.

4. The Federal-State Jurisdictional Situation Demands Clarification.

Efforts by states to support development of new generation, continued operation of existing generating units, and power supply decisions in general, are not likely to end soon. The Supreme Court's ruling in Hughes does not provide a clear pathway to accomplish these goals. The effect of the current law is to block the states protecting state interests, on the grounds that they intrude on FERC's jurisdiction, without FERC ever directly assessing the potential justification for the states' actions.

3. The Consumer-Centric Utility Business Model Provides a Viable Framework for Utilities to Continue to Provide Safe, Affordable, Reliable, and Clean Electric Service While Enabling New Products and Services

In a future state with increased consumer choices and new technologies, electric utilities will be more essential than ever. It is important to understand that electric utilities do not simply sell a commodity. They sell safe, affordable, reliable and increasingly clean electric service. They sell the assurance that the light will turn on 24 hours a day. Electric utility companies will continue to be the entities that provide this crucial public good well into the future.

The "consumer-centric utility" business model expands upon this critical service. The model provides a viable framework for utilities to continue to provide safe, affordable, reliable and clean electric service, while enabling new products and services that meet growing consumer expectations.

3.1. The Consumer-Centric Utility Integrates and Optimizes a Pool of Resources on Behalf of its Consumers While Facilitating New Service Offerings

At its most basic, a consumer-centric utility is a utility that integrates and optimizes a pool of resources on behalf of its consumers. These resources can include traditional generation, transmission, and distribution assets. They also include distributed energy resources (DER), such as demand response, energy efficiency, energy storage, and distributed generation technologies.

What sets it apart from traditional utilities is that it empowers consumers by facilitating new service offerings. New services such as community solar programs are tailored to local conditions and specific consumer preferences. It also manages risk and provides energy advice to consumers.

The general goals of all consumer-centric utilities are the same. But the model is flexible to accommodate different consumer preferences and geographic areas. What may work in the borough of Manhattan, in New York, may not be appropriate for Chapel Hill, North Carolina. The goal is not to completely redesign the industry, but to find the best way that DER and new technologies can be integrated into the system to complement and enhance the grid in a way that works for all consumers.

The responsibility of the utility remains at the meter. The opportunity for consumer-centric utilities lies behind it. In other words, the core business structure of the utility remains constant. But the business that consumer-centric utilities operate in will continue to evolve.

3.2. The Consumer-Centric Utility Business Model is the Most Efficient Model to Integrate Distributed Energy Resources Because it is Consumer Focused, takes a Long-Term View, and has Economies of Scale, Scope, and Integration

The Consumer-centric utility business model is the most efficient model to integrate DER and provide consumers with new services while continuing to provide safe, affordable, reliable, and clean energy. This is because it is consumer-focused, takes a long-term view, and has economies of scale, scope and integration.

An increased consumer focus is what separates consumer-centric utilities from traditional utilities. As consumers demand new products and services, this flexible utility would enable those services in a way that meets individual needs and works for the system as a whole.

A long-term view is important because certain grid investments are necessary to enable new solutions well into the future. An investment in a two-way metering system, for instance, may be necessary to enable consumers to control their energy usage and facilitate new services in the future.

Economies of scale can bring to bear necessary resources to invest in appropriate grid technology and enable cost-effective behind-the-meter solutions. This does not mean that the consumer-centric utility can do all of this itself.

On the contrary, partnerships with diverse third-party providers of distributed energy resources will be crucial. What the consumer-centric utility does, however, is leverage these partnerships in a way that optimizes the system and improves energy service for its consumers.

Scope and integration allow a consumer-centric utility to take a broad perspective of the system. A holistic view is necessary to understand how all of the pieces fit together.

Various system benefits may not be realized if certain investments are not made in a different part of the system. For instance, the utility could see the benefit of making investments in sensor technology in places with a high penetration of distributed solar.

A critical piece to enabling distributed energy resources is an optimized ecosystem. This ecosystem includes generation, transmission, distribution, and distributed energy resources. New technology integration must promote safe, affordable, reliable, and clean electric service.

The electricity sector is complex. Each segment of the grid is affected by every other. It will become even more complex as new technologies, and two-way flows of energy and communication, continue to proliferate. Interoperability protocols, sensors, smart inverters and other grid modernization investments are tools that consumer-centric utilities have in creating an optimized ecosystem.

A consumer-centric utility is well-suited to plan out a technology ecosystem. This is because the utility takes a long-term view and sees the system holistically.

Steele-Waseca Cooperative Electric (SWCE) provides an example of a cooperative utility that empowered consumers and provided improved electric service because it was given the freedom to find a solution that worked for its local circumstances and consumer profile. SWCE provides interested consumers with a free one hundred and five gallon grid-connected electric water heater.[29] The program allows SWCE to control 20% of peak load, passing on those savings to the consumer.

Recently, SWCE's members began expressing interest in solar energy. However, a rural co-op with fewer than ten thousand members would inevitably face monetary challenges when trying to finance a solar program. So, the utility decided to pair its existing hot water heater program with a community solar program.

[29] Steele-Waseca Cooperative Electric. http://swce.coop/

Steele-Waseca offered members who opt into the successful demand response program the opportunity to purchase a four hundred and ten watt solar panel for one hundred-seventy dollars. This amount was 90% less than the panel would ordinarily cost. The financial math worked out.

Steele-Waseca was able to save money by shifting load. And it gained extra revenue from the additional electricity sales from the water heaters.

Consumers are able to purchase solar energy from the community solar system and save money. This provides a perfect example of the advantages of scope, integration, and consumer focus.

Recommendations

1. One-Size-Fits-All Approaches to Regulatory and Market Regimes Should Not Be Encouraged.

Existing utilities should be able to continue to integrate and optimize a portfolio of resources, and enable innovative DER deployment such as community solar in a way that works for all consumers and the system as a whole.

2. Policies Should Be Designed to Allow Utilities to Optimize the Portfolio on Behalf of their Consumers.

That approach will organically lead to an energy future in which most consumer-centric utilities provide even greater resources options and services for households and businesses while continuing to support traditional goals of safety, affordability, reliability.

<u>4. DOE Should Continue to Improve the Speed and Efficiency of Technology Transfer While Not Placing Undue Burden on Utilities to Integrate or Adopt Specific Technologies</u>

NRECA is encouraged by the increasing efforts being made by the federal government to improve the speed and efficacy of technology transfer.[30] Federal research and development (R&D) funding has provided measureable results in terms of spurring innovation and creating solutions to solve challenges in a wide variety of topics in electricity and energy. However, these investments need to make it into the marketplace under sustainable technology transfer models if end users are to have access to new technologies and realize the intended benefits. The QER's broad reach across the federal sector provides a unique opportunity to evaluate and assess federal R&D investments and their impact, and to identify and promote best practices that can be used across the federal sector. The 6 of the 7 federal agencies that provided about 96% of federal R&D funding in FY 2013 and 2014[31] each have a unique impact on NRECA's mission and they have an opportunity to contribute to energy sector R&D. As a nonprofit that engages directly in R&D, we support the investment of federal funds into nonprofit sector research, and we recognize that more than a third (about 35%) of all funding to support nonprofit research comes from the federal government.[32] We commend the federal government for engaging in enabling research into technologies in a proactive manner.

While the federal government, through agencies such as the Department of Energy, enables technology transfer, it is important to ensure that technologies should not be "pre-selected" to be pursued; rather, funding should be made broadly available for all technologies – based on the need to reduce cost of those technologies – both with regard to availability, installation, operation, and integration into the existing electric grid. Further, such funding for technology transfer should necessarily include assisting consumers to understand the implications of technologies – both

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[30] Technology transfer is "the process by which technology or knowledge developed in one place or for one purpose is applied and used in another place for the same or different purpose" according to the Federal Laboratory Consortium for Technology Transfer [FLC] 2011:3.

[31] The 6 agencies are the Department of Energy, Department of Defense, National Aeronautics and Space Administration, National Science foundation, U.S. Department of Agriculture, and the Department of Commerce. The seventh agency, the Department of Health and Human Services, does not provide funding that directly impact energy sector technology development. . *Science and Engineering Indicators 2016*. 1016. National Science Board. Arlington, VA: National Science Foundation
(NSB-2016-1).

[32] National Science Board. 2016. *Science and Engineering Indicators 2016*. Arlington, VA: National Science Foundation (NSB-2016-1).

positive and negative, and create a framework that supports all technology transfers – leaving the decision to adopt a certain technology to the local communities rather than mandates and regulations. It is also important to ensure that technology transfer and innovation efforts enabled by federal government funding do not place undue burden on utilities to integrate or adopt specific technologies.

The federal government should ensure that the funding of technology innovation research and technology transfer is not driven by policy mandates or regulations. Good policymaking should consider all available technologies as options to achieve an overall long-term objective. On the flipside, policy typically lags technology, and trying to accommodate existing policies which may or may not be relevant and applicable to innovative technologies will create unsustainable incentives to advance specific technologies to the detriment of others, thus reducing the availability of technology options to address needs and challenges. Further, technology options should not be limited to availability determined solely by vendors.

The federal government should create a strategic plan with well-defined success metrics for measuring the impact of technology transfer and associated impact on field deployment. The metrics should be transparent, and directly measure and quantify the benefits realized by the consumers from the technology, along with also quantifying all relevant costs for installing, operating and integrating the technology into the existing grid. The metrics should focus more on realizable benefits under the current electric power system with a high degree of certainty, instead of positing an uncertain future in which most of the benefits will be realized. The funding for any technology innovation should have the proposed impact on these metrics as part of the decision criteria on funding innovation and technology transfer.

It is encouraging to see the federal government – especially the Department of Energy – make progress toward enabling meaningful technology transfer. However, current and proposed funding and associated activities at the DOE and the National Labs are largely inadequate. The key challenge facing DOE now is to successfully and measurably advance technology transfer in a timebound manner (before the research advances funded by DOE become obsolete or unneeded) for America's electric utilities and the industry to realize the benefits. Immediate focus should be given on developing and implementing a strategic technology transfer plan with measurable metrics, and associated funding and resources should be provided. A key element of technology transfer is the development of relationships and partnerships with utilities and private sector entities as part of a structured plan and funding specific technology transfer projects that are in national interest, in addition to the usual channels such as issuing funding opportunities – projects from which take much too long to come to fruition. Finally, technology transfer should be treated as a relationship building, ongoing activity – never prescriptive in nature – but as an enabler and provider of choices and options that encourages local decision making and those that the individual entities can choose based on their specific situation and priorities.

Recommendations

1. Funding Available for Technology Transfer Should Be Increased Considerably from Current Levels to Have Measurable Impact and Progress, and Also to Enable Projects that Assist Consumers in Understanding the Implications of Technologies – Both Positive and Negative.

The decision to adopt certain technologies over others should be left to the local communities rather than mandates and regulations. It is also important to ensure that technology transfer and innovation efforts enabled by federal government funding do not place undue burden on utilities to integrate or adopt specific technologies.

2. Technology Transfer Efforts at DOE and Other Federal Agencies Should Focus on Enabling a Framework to Support All Technology Transfers and Explicitly Leave the Decision to Adopt a Certain Technology to the Local Communities Rather than Mandates and Regulations.

Good policymaking should consider all available technologies as options to achieve on overall long-term objective. Because policy typically lags technology, attempting to create incentives to advance specific technologies to the detriment of others would result in reducing the availability of technology options to address needs and challenges. Further, technology options should not be limited to availability as determined solely by vendors.

3. An R&D and Technology Transfer Strategic Plan Should Be Created that Contains Well-Defined and Transparent Success Metrics.

These metrics should directly measure and quantify the impact of technology transfer and the currently realizable benefits realized by the consumers from the technology, along with also quantifying all relevant costs for installing, operating and integrating the technology into the existing grid. Funding for any technology innovation by federal agencies should consider the proposed project's quantified impact on these metrics as a key part of the decision criteria on funding innovation and technology transfer.

4. DOE and Other Federal Agencies Should Provide Funding for Programs to Focus on the Development of Relationships and Partnerships with Utilities and Private Sector Entities as Part of a Structured Plan, as well as Provide Funding for Specific Technology Transfer Projects that are in the National Interest.

These funding opportunities would be in addition to the usual channels, such as issuing funding opportunity announcements (FOA). Projects funded as a result of the FOA process often take much too long to come to fruition. Alternatives to the FOA process should be explored in the area of technology transfer through partnerships and other means.

5. Technology Transfer Should Be Treated as an Ongoing Activity, with Improvement in Metrics Continually Measured from a Baseline, Instead of Projects or Initiatives with Specific Start and Stop Dates.

Technology transfer is, fundamentally, a continual process that enables and provides choices and options that encourage local decision making so that individual entities can each make their choices based on their specific situation and priorities.

5. Valuation is Just One Component of the Overall Evaluation Process that Utilities Must Undertake to plan for their Systems and their Consumers

5.1. Valuation is Important, but its Benefits are Finite

"Valuation" generally means determining the net cost and benefits of primarily new resources or technologies and is a critical aspect of system planning. However, it is not the sole measure for evaluating and ultimately selecting least-cost options to meet those needs. Valuation, which is often measured through economic models, is just one component of the overall evaluation process that co-ops undertake to plan for their systems and their consumer-members. Rural electric cooperatives evaluate resources every day to determine those that best meet the needs of their member-owners. In doing this, they consider the economic benefits of the resources as well as the broader needs of the communities they serve. Traditionally, electric cooperatives have evaluated resources through the framework of providing safe, reliable, and affordable electricity to their consumer-members. In recent years, environmental sustainability (and especially carbon reduction) has become an ever increasing factor in resource decisions, for cooperatives and other utilities.[33]

While valuation studies can be informative and useful tools to help guide system investments and planning, applying them correctly is a complex process with many challenges that largely result from misunderstanding the role of valuation. The benefits of valuation are finite. Abandoning comprehensive evaluations like Integrated Resource Planning (IRP) that consider all alternatives can lead to inadequate solutions such as a sub-optimal resource mix. Valuation must not be used as a substitute for actual costs in setting electric rates which must be based on specifically-measurable, rather than implied or estimated, costs. Similarly, a valuation method should account for each value stream once-there should be no double-counting. Valuation is subjective: there is no single "standard" method for valuation, but rather many methods that can at times appear vague or even contradictory. All of these methods are heavily dependent on the inputs to the calculations, and accurate and complete information to generate those inputs is not always available. A study must be well thought-out and transparent with regard to its purpose, stakeholders, calculation and allocation

[33] Other potential metrics such as resiliency and security are dealt with separately in Section 6.

of costs and values, and consideration of alternative resources.[34] These challenges can be minimized by focusing on valuing technology locally in the context of where it is deployed.

The electricity sector is both interconnected and complex, and each segment of the grid is affected by every other segment. In order to maintain safety, reliability and affordability while increasing environmental sustainability, valuation should not be used promote specific policies or technologies, but as a tool used to help achieve the best mix of resources to balance these priorities over time.

5.2. Undervaluing Existing Resources in Assessing Carbon Reduction

The transition to a lower-carbon grid should be evolutionary, not disruptive because the availability of high quality electric power is absolutely critical to every segment of our economy Valuation is primarily a tool that state regulators and utilities use when comparing new resources. However, to the extent that national policies are adopted or changed, valuation metrics must be applied in determining the impact of those new or changed policies, at which point states, utilities and other applicable stakeholders can make reasoned decisions about which resources best fit their needs. Under this scenario, costs and benefits must be allocated appropriately and equitably. This means that resources should not be credited with societal benefits that are not related to regulatory compliance. In adopting environmental and renewable regulations, Federal and state governments have conducted their own cost-benefit analyses for balancing the societal benefits of reducing emissions with the cost of compliance. For example, valuation models that credit additional societal benefits to certain resources which are not part of the resource mix that satisfies a state renewable portfolio standard are, in effect, double counting those benefits.

With the advent of EPA's Clean Power Plan, carbon reduction has become the primary emphasis of environmental sustainability. Undervaluing existing non-emitting resources can cause major and unnecessary setbacks in progress towards a lower-carbon grid. This disconnect is best illustrated by the recent retirement or announced early retirement of nine nuclear plants, six of which are due to

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[34] In its September 2013 report entitled, "A Review of Solar PV Benefit & Cost Studies, 2nd Edition," e-Lab concluded that,
"There is broad recognition that some benefits and costs may be difficult or impossible to quantify, and some accrue to different stakeholders." Reference http://www.rmi.org/elab_empower.

"market" conditions according to the Nuclear Energy Institute.[35] This means the loss of nearly 12 gigawatts of non-carbon emitting baseload capacity by 2025, with generation equivalent to three or four times that amount of intermittent wind or solar capacity.[36] This is also an issue with hydropower, which faces pressure to breach the dams of several large hydroelectric projects in response to non-carbon related environmental concerns.

Methods of valuation that have been used to promote new low and non-emitting resources should also be used to devise methods to support valuable existing resources, especially when these are threatened financially by direct competition in markets with subsidized renewables and low natural gas prices. For example, EPA's original CPP proposal made at least some provision to protect "at risk" nuclear generation, allowing about 6% of generation from existing plants to count towards compliance.[37] Many nuclear generators complained that this was inadequate, but even this minimal provision was removed from the final plan. In recent months, attempts to address this issue legislatively at the state level in Illinois stalled, leading to the announcement of the closure of two nuclear plants in that state. An early priority for the QER 1.2 should be focusing attention on the pressing threats to the nation's two largest non-emitting generation resources, hydro and nuclear, which together account for over a quarter of U.S. generation.[38]

In addition to carbon reduction, the value of the many Essential Reliability Services (ERS) currently provided by traditional dispatchable steam, combustion, and hydroelectric turbine generation should also receive some credit. These services will often need to be provided separately from intermittent renewables, through the use of inverters, energy storage, and control technologies. Resources that

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[35] Doyle, Michael. "Why California is shuttering its last nuclear power plant." McClatchyDC. June 21, 2016. (http://www.mcclatchydc.com/news/nation-world/national/article85091512.html)

[36] Nuclear retirements come from various sources:
1) For nuclear retirements other than those listed below, EIA has projected retirement dates in EIA-860: Annual Generator Inventory Report 2015-Early Release (https://www.eia.gov/electricity/data/eia860/)
For units already retired or announced EIA 860 2015 Early Release (https://www.eia.gov/electricity/data/eia860/)
2) Quad Cities and Clinton plant retirements announced (http://www.utilitydive.com/news/exelon-to-shut-clinton-quad-cities-nuclear-plants-after-illinois-bill-stal/420237/)
3) Fort Calhoun plant retirement announced (http://www.utilitydive.com/news/omaha-public-power-plans-to-shutter-nations-smallest-nuclear-plant/419205/)
4) Diablo Canyon plant retirement announced (http://www.utilitydive.com/news/pge-to-close-diablo-canyon-nuclear-plant-replace-it-with-renewables-effi/421297/)

[37] Section 4.4 Nuclear Energy, EPA TSD for GHG Abatement Measures pp. 4-32 to 4-35 (https://www.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf)

[38] EIA 2015 (https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3)

make these contributions to reliability and are non-emitting, such as nuclear and hydro, are especially valuable and should not be retired.

Between 2014 and the end of 2016, roughly 25 gigawatts of coal capacity accounting for more than 10% of the US total capacity will have been retired due to low natural gas prices and non-carbon environmental regulations (e.g. MATS).[39] This very rapid retirement of nuclear and coal baseload generation is likely to present major challenges for grid reliability in coming years, as gas pipeline and storage and electric transmission systems must be upgraded and expanded to reflect the shift of the energy mix towards gas and renewables. Properly compensating ERS provided by existing generation facilities would give some relief in the short and mid-term to remaining coal units, many of which have recently undergone costly environmental compliance upgrades. Recognizing the contribution of these resources to the electric grid through the QER 1.2 would help to reduce the threat of stranded asset costs to utilities and help preserve grid stability, without having a major impact on carbon emissions in the long-term.

5.3. Valuing Distributed Energy Resources

When evaluating Distributed Energy Resources (DER), "value" is merely a component on an integrated process. DERs are often promoted as a goal in and of themselves, rather than as option for providing safe, affordable, reliable, and environmentally-sustainable energy services. The push to prioritize deployment of new DER technologies outside of an integrated planning process such as an IRP to balance costs and benefits across a utility system can lead to sub-optimal investments and results, and higher costs to consumers.[40]

As an example, a major 2015 study by MIT found that while solar PV can contribute greatly to meeting energy needs while reducing carbon, current policies are not promoting the lowest-cost options to meet these goals. Notably, the report found that residential PV systems (under 10 kW) are 70% more expensive than utility-scale PV systems (1 MW or larger), and can become even more

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[39] Six coal retirements were about 12% of nationwide capacity as of 2013; 2013 U.S. coal capacity and retirements are from the EIA 860 2015 Early Release (https://www.eia.gov/electricity/data/eia860/)
[40] See NRECA February 28, 2014 Comments to DOE RFI: Net Costs and Benefits of Solar

expensive at higher penetration levels due to the need to integrate these generating resources with distribution systems that were designed for radial (one-way) power flows to the customer meter. The study found that due to the structure of subsidies for solar generation, especially state net-metering policies that actually favor more expensive systems, development is skewed towards more expensive small-scale residential systems rather than less costly utility-scale solutions.[41] Performing a cost-benefit analysis for distributed solar PV, without considering other options can produce unreliable results. Alternative resources, including demand-side management programs, can provide the same or even additional benefits (i.e., reliability) as PV. This is not to say that there is not a place for rooftop solar, but that when possible it should be deployed as part of an integrated and optimized portfolio of resources where its unique characteristics are of the most value and do not result in cost-shifting.[42]

The QER 1.2 should continue to support development of data on resources and technologies that create a level playing field between technologies, instead of relying upon valuation methods that may be skewed towards one technology or another. This will allow utilities, customers, and developers to pursue the best technology based on costs and local conditions. Cooperatives and other consumer-centric utilities (CCU) should have a major role in planning the deployment of DER in ways that provide the most value across the grid network. Rooftop solar might make sense for some systems, while others might find more value to their system and consumers in placing larger 1-5 MW utility-scale DG PV projects in the correct area to relieve congestion and reduce the need for T&D system upgrades, others might find that other DERs such as demand response and energy efficiency programs deliver more value than solar for their system.

Valuation methods should recognize that DER is not the solution for all system and consumer needs. While DER has a major role to play in reducing greenhouse gas emissions, it should not be favored in all cases over other options, such as large-scale renewables. While DG solar has captured many peoples' imaginations, the vast majority of the nation's renewable generation still comes from

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[41] "The Future of Solar Energy." MIT, May 2015 (http://mitei.mit.edu/futureofsolar).

[42] Through the Solar Utility Network Deployment Acceleration Project (SUNDA), NRECA is working in partnership with DOE and over a dozen member cooperatives to help reduce the barriers of entry and the costs for cooperatives deploying utility-scale DG solar (1 MW and above) through standardized designs, business models, finance and insurance options. SUNDA has produced resources and educational materials that are available to all cooperatives and provide guidance for co-ops in any stage of project deployment. These materials are publically available and have been accessed and used not just by cooperatives, but by other utilities both in the U.S. and abroad.[42] http://www.nreca.coop/what-we-do/bts/solar-utility-network-deployment-acceleration-project/

large-scale resources, such as wind that provides nearly 5% of U.S. generation[43], primarily from large-scale farms.

New additions to the grid, like solar panels, energy storage, micro grids and distribution system operating functions will require new thinking in terms of how cooperatives recover their revenue requirement from consumer-members who are paying for different energy services and products. State policies that pick winners and losers today, such as value-based methodologies for compensating DER, will need to be modified to give CCUs and their consumers more latitude to optimize investments for the benefit of all consumers. That approach will organically lead to an energy future in which most CCUs provide even greater resource options for households and businesses while continuing to support traditional goals of safety, affordability, reliability, rate stability, and environmental sustainability. Not only do these energy services and system enhancements meet consumer desires, they can be deployed in ways that enhance the resiliency of the electric system.

As DER deployment grows, however, there will be greater challenges around system voltage regulation, protection, safety and other areas based on the grid's baseline design historically intended to manage power that flows in one direction only, from generation to load. CCUs and grid operators will play a critical role in managing this adaptation in a manner that does not disrupt reliability or greatly increase cost of service to consumer-members.[44]

5.4. Valuation is Not a Substitute for Integrated Planning or Rate Design

As noted above, valuation studies can be part of, but are not a substitute for, an IRP process. Rate design requires actual costs to be fairly allocated on a non-discriminatory basis among consumer classes. While a well-designed valuation study that focuses on market costs can be a valuable tool to assess and reduce cross-subsidies between different groups of consumers, or to value a potential

[43] EIA 2015 (https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3)

[44] NRECA is actively involved in research to address these challenges. The GridBallast Project, also in partnership with DOE seeks to create inexpensive autonomous controls that can be placed on electric water heaters and other home appliances to provide frequency regulation to cope with unexpected ramping of solar PV generation.[44] http://www.nreca.coop/doe-selects-nreca-to-optimize-distributed-energy-resources/

DER resource such as distributed solar PV, at the end of the day utility rate tariffs are generally designed to recover a utility's embedded "cost" of service for the entire system rather than assessing the "value" of a discreet service or resource.

For example, a distribution cooperative introducing a value of solar (VOS) tariff outside the IRP process conducted by its Generation and Transmission Cooperative (G&T) jeopardizes the optimized foundation upon which economically efficient resource decisions and thereby retail rates are based. Launching a VOS tariff to address rooftop solar, for example, may be capable of crediting avoided energy costs (if the VOS accurately reflects costs and benefits), but this does not mean that rooftop solar is the optimal sustainable resource option. Community solar and utility solar are generally lower cost resources, and a valuation study in the context of an IRP might help identify the optimum mix between these resources for a utility seeking to deploy solar. As consumer-owned utilities, electric cooperatives seek to assist their members who desire to deploy PV at their homes or businesses, while also equitably allocating grid system costs in ways that do not result in cost shifts and fairly compensating DER consumers for the value their DER provides to the system.

This is a balancing act which many cooperatives are finding requires a reassessment of rate design and charges based on specifically-measurable actual costs, rather than valuation results. As is the case with valuation models, there is no one-size-fits-all rate design to prepare utilities for the future. While many cooperatives across the country are experiencing significant growth of DER, they are addressing it by deploying a variety of rate structures tailored to meet the needs of their respective consumer-members and systems. St. Croix Electric Cooperative (SCEC) in Wisconsin phased in a revised net metering charge that is an enhanced avoided cost rate that considers daytime solar hours. SCEC also added capacity credits during peak billing hours and a grid charge for net-metered customers. After the Vermont Legislature increased net metering on utility systems from 4% to 15% of peak demand, Washington Electric Cooperative (WEC) in Vermont received approval from the Vermont Public Service Board to implement a grid fee for net-metered consumers and to amend its excess generation credit, consistent with the rates stipulated in the Vermont legislation. Bandera

Electric Cooperative (Bandera) in Texas is taking a different approach and is restructuring its fixed-charge component into two categories: an availability charge and a delivery/distribution charge.[45]

At the wholesale level, G&Ts base their wholesale rate design on the cost of service (COS) studies. A G&T cooperative's wholesale COS study is focused primarily on functionalizing the revenue requirement between generation and transmission and then classification between capacity and energy. While this is also the case with distribution cooperative retail COS studies, a G&T cooperative COS study is typically very closely reflected in the resulting wholesale rate design. The capacity-related costs are recovered in some type of capacity (i.e. per kW) charge and the energy-related costs are recovered in some type of energy (i.e. per kWh) charge. G&Ts utilize IRPs for long-term resource planning to meet the needs of their distribution co-ops and comply with environmental and policy obligations in a least-cost manner.

The IRP and rate design processes allow cooperatives to plan for and balance uncertainty and risk on behalf of their members, with G&Ts looking out for their distribution member cooperatives and distribution cooperatives looking out for the consumer-members at the end of the line.

5.4.1. Distribution Cooperative Planning Process

In planning at distribution cooperatives, technical solutions and economics are interwoven with local knowledge in order to rank possible solutions and arrive at the one most appropriate for a given situation. Economic valuation methods and engineering analysis are important, but they must be balanced with difficult to quantify yet vital considerations such as member-consumer expectations, landowner demands, workforce considerations, and safety of both workers and the public. Rigorous economic and engineering analysis is both warranted and helpful for large-scale projects, however at the local level they can sometimes lead to unnecessarily complex analysis of simpler projects that cooperative staff can handle quite effectively based on standard procedures and their firsthand knowledge of the system.

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[45] St. Croix Electric Cooperative: Toward an Equitable Net-Metering Rate Design, July 1, 2016, Washington Electric Cooperative: Operating in a Challenging Net-Metering Environment, July 1, 2016 and Bandera Electric Cooperative: A Rate to Reflect the Wholesale Market, July 1, 2016. See also, Power System Engineering, Inc.: Survey: Electric Cooperative Fixed Cost Recovery, 2014.

Co-op managers are continually examining their system conditions, the expectations of consumer-members and the state of technology to determine what incremental grid modernization investment is needed. This ongoing exercise to examine the distribution environment allows co-ops to consider enhanced grid technologies that can address certain operational needs or challenges, while being cost effective for consumers. Beyond hardware investments, cooperatives use information technology and data analytics software to improve service and provide additional value to their members.

Technological deployment decisions require an in-depth understanding of the costs, risks, and benefits associated with those technologies and how they will affect the operation of an electric provider, as well as how to integrate new resources with existing resources, which may include simulation software for planning, integration and operation of DER.

Individual distribution co-ops conduct Load Forecasts, often in cooperation with their G&T, to support Construction Work Plans (CWPs). These studies are typically performed on a regular (usually annual) basis. They typically include expected changes in numbers of consumers, energy and demand by class (residential, commercial and industrial). Forecasts are provided on an annual and, in some cases, monthly basis. Monthly demand forecasts can be especially important due to seasonal variations. If DSM is a factor, demand is forecast with and without DSM so financial models can account for differences in demand costs while engineering studies can use peak demands to project capacity requirements. Forecasts may be provided on an aggregated system basis, by delivery point or both.

For cooperatives who borrow from the Department of Agriculture, Rural Utilities Service (RUS), the CWP summarizes engineering and construction needs of the co-op for a 2-4 year period and provides the studies and projections to support the request for loan funds to facilitate necessary construction. Most non-RUS borrowers follow these same guidelines. Load forecasts are a critical tool for distribution co-ops to support financial and rate studies.

Distribution co-ops have been using engineering models of their distribution systems for many years. They are used for conducting a variety of studies including loading, voltage levels, system losses, sectionalizing, and reliability. These studies, in turn, are used in a number of analysis and planning scenarios ranging from immediate challenges to long-range planning studies. The models help identify emerging problem areas and evaluation of alternate solutions for efficacy as well as setting priorities.

Many co-ops have staff engineers who are proficient with the necessary software and perform these studies in-house. Others provide system maps and circuit, load and voltage data to an engineering consultant who runs the studies for them. Virtually all, however, have their systems modelled and rely on the analysis of these models to help analyze and set construction, maintenance and improvement priorities for the co-op.

Looking ahead, software which can analyze engineering models with multiple DERs will become critical. Most of the software used for distribution engineering studies is based on one-way (radial) flow of power and does not work well when more than one source is connected. When multiple flows are possible, analysis becomes more akin to that of the transmission system. DERs create both challenges and opportunities for distribution systems, but the lack of readily usable software to perform reliable engineering studies is starting to create significant difficulties for system planners. Continued proliferation of DERs will escalate both the relevance and importance of these studies and the need for software which can be readily used by distribution engineers.[46]

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[46] NRECA has led the development of the Open Modeling Framework (OMF), a next generation engineering modeling tool developed with a goal of making advanced power systems models usable in the electric cooperative community. The OMF is being developed as a versatile modeling tool that enables co-ops to evaluate smart grid components and DER using real-world data prior to purchase. This enhanced modeling tool can support co-op investment decision-making by modeling the cost and benefits, incorporating engineering, weather, financial and other data specific to the co-op. OMF allows the dynamic modeling of multiple DERs on a single system to help co-ops optimize deployment and determine the most cost-effective solutions. OMF provides common data models, configuration management tools, run execution and visualization capabilities for use with multiple models, including the Pacific Northwest National Laboratory's Gridlab-D and the National Renewable Energy Lab's System Advisor Model. A beta version of the OMF is hosted on the cloud and accessible to the public online. https://www.omf.coop/
NRECA is also providing leadership in the area of interoperability. The MultiSpeak® Initiative is a collaboration of NRECA, utility software vendors, and electric distribution utilities worldwide. MultiSpeak® is the leading standard for enterprise level software interoperability, allowing for information sharing between systems in a cost effective and standardized way. MultiSpeak® enables the Smart Grid and saves both vendors and utilities time and money by simplifying software integration and minimizing expenses for custom interface solutions. It strengthens software applications and adds value to IT investments. For example, an AMI (Advanced Metering Infrastructure) system automatically reporting the power outages to an independent Outage Management System (OMS) via MultiSpeak adds tremendous value to both investments.
The MultiSpeak Specification is the most widely applied de facto standard in North America pertaining to distribution utilities and all portions of vertically-integrated utilities except generation and power marketing. It is the only interoperability standard of its type listed in the NIST-SGIP (National Institute of Standards and Technology Smart Grid Interoperability Panel) Catalog of Standards. It is used in real time operations on more than 725 plus electric cooperatives, investor-owned utilities, municipals, and public power districts in at least 20 different countries worldwide.

5.4.2. G&T Planning Process

As mentioned above, G&Ts work interactively with their member distribution cooperatives to produce load forecasts. Once a G&T has collected the information it needs from its distribution members, the data is combined to produce an aggregated load forecast for their entire system, a critical piece of their overall system planning. These load growth assumptions are then used in resource planning.

In the resource planning process, G&Ts primarily use economic models to review bids and self-build options for selecting least cost technologies and resources to meet their needs. Existing data is used as a base case, and sensitivities are run using assumptions such as future fuel or CO2 prices.

Economic valuation models are an important tool for forecasting trends and projecting market results, as one part of a broad and thorough decision-making process. However, G&Ts do not rely upon model estimates as a sole solution, but rather as a complement to real-world data and expertise. Models are designed to simulate scenarios to provide an educated guess regarding something that is not already known. For example, a G&T would have access to a plethora of information on its own financial situation, fleet performance, and future strategy, but in making a decision would also want to account for external information, such as the operation of other entities and units, and future market conditions. A model provides great value in estimating the unknown, but even the best models are simplified and unlikely to completely reflect reality.

5.5. Other Valuation Models are Needed to Make Better Decisions

Any model must rely on a particular set of input assumptions about the market that is being examined. In the electric industry, this can include a variety of factors, such as forecasted fuel prices, load projections, or construction costs. Often, due to the time taken to update modeling assumptions, there is a lag between the best available data and what is in the model. As with any type of model, valuation model output results are only as strong as their associated inputs, and one should always caution the use of a model that relies on assumptions that are incomplete or unsound.

Most models were developed for compartmentalized planning, and there is no single model that captures all aspects of the industry. Therefore, just as real-world data should necessarily be incorporated in the evaluation and decision-making process, so should output from other models in addition to valuation models. An economic dispatch model can provide helpful estimates of expected generation and future market prices, but may not account for transmission, for example, so the best strategy is to take a holistic approach in considering all relevant data points.

Economic dispatch models are generally accepted as a trusted and valuable tool for simulating the generation side of the industry, but transmission and distribution are more difficult to model, and will become even more challenging with new developments in DER and storage. Committing to a specific model or framework for either transmission or distribution could be problematic and premature, given the current analytic capability.

Economic dispatch models are agnostic, in that they use a set of market input assumptions to meet load in a least-cost manner, subject to any constraints, without regard to non-market circumstances such as ownership. Thus, when determining the appropriate dispatch, two units in the same fleet would be treated the same as two units from different owners. This can potentially be problematic for entities that make decisions across a group of units, rather than on an individual basis.

Currently, the further out the projections for project resource needs, the more uncertain the results. The potential exists to use stochastic modeling to better refine and add more certainty in future decision making. Monte Carlo simulation, for example, allows planners to assess risks and analyze a variety of potential outcomes, through the use of repeated random sampling. For any uncertain factor, a range of values, based on a given distribution, can be used in calculating results over thousands of iterations. This provides decision-makers with a range of possible outcomes and the probabilities they will occur, which ultimately leads to a more robust understanding of consequences in an uncertain world. The QER should support the development of improved modeling tools to assist utilities plan and optimize their systems and the electric grid over the next decades.

Recommendations

1. Valuation Methods Should Be Technology-Neutral.

Valuation is one of many tools that electric utilities have at their disposal to plan for new services and technology in order to promote safety, reliability, affordability, and environmental sustainability. As such, valuation methodologies should not be biased in favor of certain technologies over others.

2. Valuation Methods Should Recognize the Valuable Contribution of Existing Hydro and Nuclear Resources to Grid Stability and Reliability.

Allow utilities to pursue the optimal resource mix that recognizes the broader needs of consumers and their communities for grid safety, reliability, affordability, and environmental sustainability. While increased DER appears attractive, sub-optimal resource allocation can result in cost-shifting to consumers without DER. Electric utilities should play a significant role in planning and deploying DER in a consumer-centric manner, while also acknowledging the importance of other resources, including utility-scale solar, in meeting environmental goals.

3. Valuation Methods Should Not Be Tailored to Support One Form of Risk Assessment and Management over Another.

Electric cooperatives are in the business of managing risk on behalf of their member-owners. Integrated resource planning and rate design, both of which are core utility industry practices, allow for iterative assessment and balancing of uncertainty and risk based on local conditions. Regulatory risk assessment mandates would be duplicative, and would not serve a valuable function.

4. Resources Should Not Be Credited with Societal Benefits that are Not Related to Regulatory Compliance, Through Valuation Models or Any Other Mechanisms.

In adopting environmental and renewable regulations, Federal and state policymakers have conducted their own cost-benefit analyses for balancing the societal benefits of reducing emissions with the cost of compliance. Valuation models that credit additional societal benefits to certain resources which are not part of the resource mix that satisfies a state renewable portfolio standard, for example, are in effect double counting those benefits.

6. A Resilient and Secure Electric Transmission and Distribution System is Vital

As member-owned, not-for-profit organizations, America's Electric Cooperatives focus on providing safe, reliable and affordable electric service. At the crux of this service is a resilient and secure electric transmission and distribution system that powers the communities that co-ops serve.

6.1. Evolving Trends and Conditions are Providing the Next Wave of Resiliency Issues

Electric cooperatives have taken significant steps to improve resilience, and also face new challenges in the ever-evolving electric industry. While infrastructure improvements have made the electric system more resilient, new challenges create a complex future for the electric industry. Evolving industry trends and changing conditions, as well as issues surrounding resilience self-assessment tools and insurance, are providing the next wave of resiliency issues for the electric industry.

6.1.1. Current Practices in Improving Resilience are Successful

Addressing resiliency requires understanding the two main foci by which it revolves: human/process and electric/electrical. The human and process focus requires specialized skilled employees who understand the electric system. Our member electric cooperatives maintain highly skilled crews with the requisite knowledge to plan and execute the complex actions needed to restore power when the electric system is taken offline. Electric co-operatives have also taken practical and substantive actions to improve resilience through infrastructure investment. This has included the undergrounding of distribution lines, as well as the further hardening of transmission lines in high weather risk areas.

6.1.2. Distributed Energy Resources Make Resiliency Management More Difficult

Distributed energy resources (DER) have increased complexities in managing and promoting resilience. DOE's Advanced Research Projects Administration has funded research led by NRECA, called GridBallast, focused on improving resiliency and controlling peak demand. GridBallast is developing low-cost demand-side management technology that addresses resiliency concerns associated with the growth of DER. The technology being developed will work to control demand by cycling electric appliances on and off in an autonomous fashion in response to changes in DER output. By working on proactive and innovative solutions at the intersection of DER and resilience, NRECA is placing an emphasis on the importance of load management in a resilient electric distribution system. NRECA appreciates the ongoing partnership with DOE in our joint effort to build a more resilient electric distribution system. However, research and development efforts that are needed to achieve a more resilient electric distribution system are wide ranging, and must be focused on practical, near-term applications that the electric industry and consumers can actively use.

6.1.3. While Well-Intentioned, Resilience Self-Assessment Tools Could Create Security and Regulatory Issues

Maintaining a resilient system in the face of evolving trends and changing conditions has presented a significant array of challenges to electric cooperatives. While well-intentioned, DOE and the National Labs' interest in developing a resilience self-assessment tool could create security and regulatory issues for electric co-cooperatives. Our member utilities have many years of experience preparing for and responding to electric system threats associated with severe weather, natural disasters, critical equipment failures, vandalism, isolated physical attacks and other issues. A resilience self-assessment tool that asks for resilience data creates confidentiality and misuse concerns that would detract from the value of the tool.

Electric cooperatives provide a critical and security-sensitive service to 42 million Americans. While providing electric services, cooperatives gather the energy usage data of end-use consumers. A resilience self-assessment tool creates confidentiality concerns if cooperatives were asked to submit electric distribution resilience data. Specifically, this places end-use consumer confidentiality at risk. Ineffective data methodologies could allow potentially malicious analysts to infer energy usage of specific end-use consumers, creating enormous privacy concerns. Such security concerns could also place critical customers at risk of hostile party attacks. Customers that use specific distribution infrastructure in their operations could have that the details of their infrastructure inferred from ineffective data, leaving them open potential attacks and severe operational impacts.

Each and every electric cooperative is different, with wide variety in terms of their location and climate, customer density and composition, the age of their delivery systems, etc. With a diverse set of factors playing a significant role in the daily operations of electric cooperatives, resilience performance is different between each electric cooperative. Any reasonable analysis of resilience would have to take such differences into account. A resilience self-assessment tool that aggregates data to create national average resilience values leaves potential for misuse and misinterpretation of these values. The use of a national average value for some parameter of resilience performance would almost certainly be misleading and inappropriate, and could be harmful, in the face of the diverse set of factors that impact each different electric cooperative.

A better use of the Department of Energy and National Labs' resources would be in developing distribution resiliency best practices for the electric industry. A product similar to the Electricity Subsector Cybersecurity Capability Maturity Model and the Smart Grid Maturity Model would be of value to the industry. In this product, best practices would be grouped under four key resilience domains: preparedness, mitigation measures, response and recovery. Further development would allow for subcomponent formation. In showcasing best practices in each domain, industry members could make informed decisions on strengthening resiliency based on easily identifiable areas for technology investment and improved operating procedures. Further development could also yield the basis for a Maturity Model for Distribution System Resilience.

6.2. Cyber and Physical Security in the Electric Industry is Mostly a Story of Success, Though There is Always More to Do

Electric cooperatives constantly monitor, identify, and mitigate potential risks associated with the electric transmission and distribution systems, especially as cyber and physical security threats rapidly evolve. Efforts have been undertaken by the North American Electric Reliability Corporation (NERC) to develop and enforce cyber and physical security standards. Additionally, cooperatives use security best practices from NRECA and a variety of other sources. Cyber security in the electric industry is mostly a story of success, while acknowledging that there is always more to do in the changing cyber landscape.

6.2.1. Cooperatives are Actively Focused on Cyber Security

NRECA has taken an active role in the evolving cyber security field through member education and regular industry and public policy engagement. Member education is often provided by workshops and webinars focused on cyber security issues and tools for member cooperatives. These opportunities allow members to remain knowledgeable about the evolving world of cyber security, while also providing tools to ensure that electric cooperatives remain as secure as possible.

6.2.2. Cyber Security Industry Standards Provide Excellent Guidance

NERC presently has a suite of mandatory and enforceable cyber and physical security standards that electric cooperatives use, if applicable, in protecting their BES assets and systems. Although not mandatory and enforceable standards, DOE's ES-C2M2 and NRECA's cyber security framework provide valuable tools that cooperatives can use as best practices. DOE's ES-C2M2 is a part of a larger cybersecurity-focused public-private partnership built to improve cybersecurity in the energy industry. ES-C2M2 focuses on "implementation and management of cybersecurity practices associated with the operation and use of information technology and operational technology assets and the environments in which they operate."[47] NRECA's CRN has also developed operational tools, policies, and frameworks to assist our members in their growing cyber security needs. Focused mostly on protecting sensitive customer data, reliability and productivity, NRECA has worked to ensure that its members remain aware and proactively engaged to ensure the security of their data, assets, and systems.

[47] http://energy.gov/oe/services/cybersecurity/cybersecurity-capability-maturity-model-c2m2-program

6.2.3. Best Practices for Physical Security are Focused on Many Issues

Severe weather, along with system failure, vandalism and physical attacks, all threaten the electric transmission and distribution systems. Electric cooperatives have always taken a proactive approach to managing the physical security of their facilities, and this is especially important as it relates to the attack at the Metcalf Substation in California and the cyberattack in Ukraine that involved the unauthorized use of control systems for their electric distribution system, resulting in circuit breakers being opened and causing power outages for 225,000 customers. NERC standards exist for the most critical Bulk Electric System (BES) transmission lines and their associated control centers. Additionally, best practices for physical security are focused on many issues, including hardening infrastructure and eliminating potential lines of sight for attack.

DOE has also expressed interest in the physical security and resilience of the electric transmission and distribution systems, as they expressed in their Request for Information on a National Power Transformer Reserve. Large power transformers (LPTs) are critically important components of the BES, as evidenced by the number of electric utilities that maintain or share spare LPTs through bilateral/multilateral arrangements and a variety of privately run programs. Three of these programs – EEI Spare Transformer Equipment Program, SpareConnect and Grid Assurance – all work to support recovery from LPT failure, making a National Power Transformer Reserve largely duplicative. Should a National Power Transformer Reserve be created, the electric utility industry would be the best administrator for this program with input from appropriate governmental organizations. However, the best opportunities in the field of LPTs for DOE are in new programs or partnerships. A focus on standardization of design and manufacturing, targeting voltage class and sizes at highest risk, research and development for new "temporary" or flexible rapid deployment high voltage transformers and government support in addressing transportation and infrastructure deficiencies or challenges would all better use of resources by the Department of Energy.

6.2.4. Prediction Capabilities Must Be Improved to Enhance Resilience

Increased prediction capabilities for geomagnetic disturbances (GMDs) and weather will allow for better transmission and distribution system security. While the historical and scientific data on geomagnetic disturbances remains limited, the potential for significant impacts by these events make them a high priority for increased prediction capabilities, as well as reliability standards in the case that these events occur. FERC, NERC, and the industry worked together to develop two stages of reliability standards. The first stage, which has been approved by FERC, focuses on "operating plans, procedures and processes to mitigate effects of GMDs", while the second stage (not yet approved by FERC) will potentially require vulnerability assessments for one-in-100-year GMD events to meet certain performance requirements.[48] While these reliability standards leave the electric industry better prepared in the event of a GMD, more research must be done by the federal government to develop better forecasting and warning systems for GMD events. Similarly, research related to improving weather prediction capabilities will also assist the reliability and resilience of the electric transmission and distribution systems.

6.2.5. Security Research and Partnerships Should Remain a Priority

DOE has functioned as a valuable research partner in developing new technologies and strategies across the electric industry, including in cyber and physical security. DOE's ES-C2M2 serves as an excellent example for successful engagement and cooperation between government and the electric industry to further overarching policy goals of both parties. The Cooperative Research Network (CRN) provides a platform for innovative collaboration between the Nationals Labs, electric cooperatives and other industry players. With a focus on technology that benefits consumers, CRN provides a platform for demonstration and application of technology in real-time at the member level. With sustained collaboration and engagement, DOE and the electric industry can work together to focus on research with practical, near-term applications. Further collaborative efforts and research partnerships with the National Labs will enhance security technologies.

[48] http://www.ferc.gov/media/news-releases/2015/2015-2/05-14-15-E-1.asp#.V1iHdk32a70

Recommendations

1. DOE and the National Labs Should Pursue the Creation of Resiliency Resources Other than Metrics.

A resilience self-assessment tool creates a host of confidentiality and misuse concerns that could place private consumer data at risk and lead to distorted analysis of resilience data when compared to average national values. Instead, a better use of DOE resources would be in the creation of a resiliency best practices database that focuses on preparedness, mitigation measures, response and recovery. This would allow for informed industry decision making and could yield a longer term Maturity Model for Distribution System Resilience.

2. We Encourage DOE to be a Research Partner with Industry in Focusing on Practical, Near-Term Applications.

In the fields of both physical and cybersecurity, DOE should continue to focus on research partnerships with industry. While large power transformers remain a relevant security concern, DOE should not create a duplicative sharing program, but should instead focus on research flexible rapid deployment transformers, standardization of design and manufacturing, and other current infrastructure challenges. Further research on GMDs, weather prediction and cybersecurity best practices will also yield additional resilience benefits for the electric utility industry.

7. Environmentally Beneficial Electrification Should Be Incentivized

An emerging consensus is growing that meeting aggressive GHG reduction goals will require electrification of end-uses such as space/water heating, and transportation. A recent report by Environmental and Energy Economics (E3) states that "critical to the success of long-term GHG goals" is "fuel-switching away from fossil fuels in buildings and vehicles."[49] Lawrence Berkeley National Laboratory similarly concludes that "widespread electrification of passenger vehicles, building heating, and industry heating" is essential for meeting California's GHG reduction goals.[50] Work at Stanford University also indicates that "one potential way to combat ongoing climate change, eliminate air pollution mortality, create jobs and stabilize energy prices involves converting the world's entire energy infrastructure to run on clean, renewable energy."[51] The United Nations Sustainable Development Solutions Network's Deep Decarbonization Pathways Project, the California Council of Science and Technology[52], the Acadia Center's EnergyVision report[53], experts like Jeffrey Sachs of Columbia University[54], and even Bill Nye the Science Guy[55] have all added to this chorus. Many other researchers around the globe are echoing the same conclusions.

However, current US energy policies provide a disincentive for using electricity for more end-uses. For example, most energy efficiency policies focus on reducing the overall kWh of electricity generated and consumed in states. This provides a disincentive to add electric space and water heating and electric vehicles to the grid, even though doing so would reduce carbon dioxide emissions. Mass-based electric sector emissions caps likewise provide a disincentive to add new electric leads because they do not account for reductions in emissions associated with reduction in use of fossil fuels in homes and vehicles. As electricity from the grid becomes cleaner, U.S. energy policy will need to be rearranged to incentivize environmentally beneficial electrification.

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Recommendations

1. DOE and EPA Must Correct the "Source" Energy Factor Used in Energy Efficiency Policies

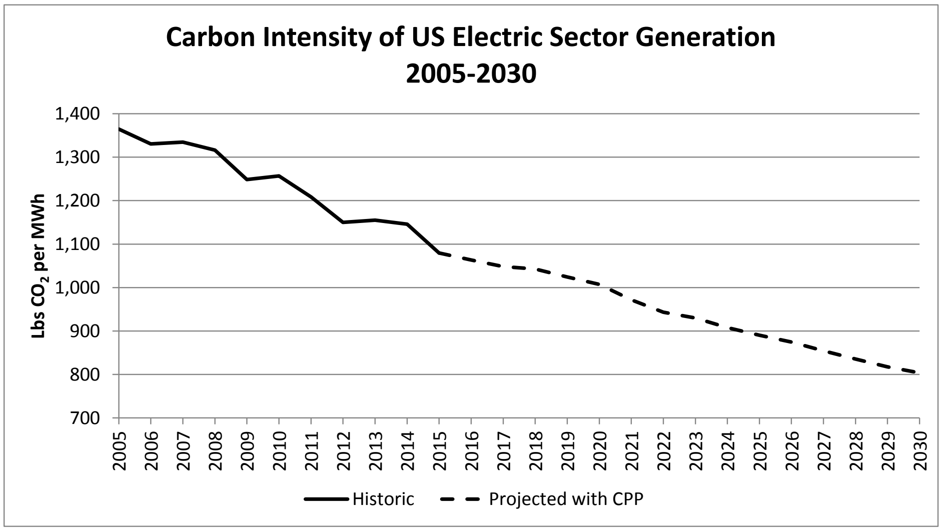
As discussed at length in a November Article of The Electricity Journal titled "Environmentally Beneficial Electrification: Electricity as the End-Use Option,"[56] the "source" energy metric used by DOE and EPA in energy efficiency policies and tools is flawed. The metric inappropriately penalizes non-emitting generation sources, including renewable and nuclear energy, treating it as only about one-third the efficiency of on-site fossil fuel-combustion alternatives. In joint comments to a DOE request for information on this topic, the Natural Resources Defense Council (NRDC), National Rural Electric Cooperative Association (NRECA), Edison Electric Institute (EEI), and American Public Power Association (APPA) outlined an approach to transparently disclose the calculation methodology for this metric and asked EIA to annually report a "fossil fuel source energy" metric that could be used in place of the current flawed metric. This would level the playing field among energy alternatives and thus represents a common sense solution to rectifying the source energy metric.

2. "Incremental Emissions Factors" Should Be Used Instead of "Marginal Emissions Factors" to Account for New Energy Loads' Impacts on Energy Efficiency Programs

When accounting for emissions associated with the addition of new electric load, DOE should recognize that the emissions intensity of the grid is changing with time. This trend is reflected in Figure 1 below, which was constructed with EIA data.

[56] Dennis, K. 2015. "Environmentally Beneficial Electrification: Electricity as the End-Use Option." Electricity Journal 28(9): 100–112

Figure 1. Carbon Intensity of U.S. Electric Generation, 2005–2030[57]



Current emissions accounting methods typically reflect existing generation using marginal emissions factors, often with outdated data, and do not reflect the impacts of the grid's the changing fuel mix or technology improvements which reduce emissions over time. Energy efficiency programs should seek to apply emissions factors that reflect the changing nature of the generation fleet that will be serving the new electric loads.

According to EIA, "electric generating facilities expect to add more than 26 gigawatts (GW) of utility-scale generating capacity to the power grid during 2016. Most of these additions come from three resources: solar (9.5 GW), natural gas (8.0 GW), and wind (6.8 GW), which together make up 93% of total additions. If actual additions ultimately reflect these plans, 2016 will be the first year in which utility-scale solar additions exceed additions from any other single energy source."[58]

Using reasonable capacity factor assumptions and emissions rates, this new generation could produce 92.5 MWh per year at an emissions rate of about 0.26 short tons of CO_2 per MWh.[59] This ***incremental emissions factor*** should be used to assess the impact of new electric loads added to the grid, such as electric vehicles and electric space and water heating.

[57] Derived from EIA data: AEO 2016 (projections), Monthly Energy Review April 2016 (historic).
[58] EIA. Today in Energy. March 1, 2016.
[59] This could be considered the "incremental" emissions factors associated with adding new electric loads to the grid.

Table 1. Estimated MWh Generation and Emissions from Expected 2016 Generation Additions

Type	New Capacity (GW)	2015 Average Capacity Factor	Estimated Generation (MWh)	Emissions Rate (Tons/MWh)	Emissions (Short Tons)
Solar	9.5	28.6%	23,800,920	0.00	0
Natural Gas	8.0	56.3%	39,455,040	0.61	24,067,574
Wind	6.8	32.5%	19,359,600	0.00	0
Nuclear	1.1	92.2%	8,884,392	0.00	0
Petroleum and Other	0.3	1.3%	34,164	0.82	28,014
Hydro	0.3	35.9%	943,452	0.00	0
Total	**26.0**	**40.6%**	**92,477,568**	**0.26**	**24,095,589**

3. "Emissions Efficiency" Should Be Considered Instead of "Energy Efficiency" in Energy Policies Designed to Reduce Emissions

In order to maximize GHG emission reductions, energy efficiency should be re-thought of as "emissions efficiency". Emissions efficiency is a more effective way to measure progress towards reducing total GHG emissions attributed to the residential energy sector. Consider the "energy efficiency" of an electric water heater in terms of gallons of hot water produced per kWh, or an electric vehicle in terms of miles driven per kWh. Typically their energy efficiency will not change significantly over their operating lifetimes: an electric vehicle produced today will operate with roughly the same miles-per-kWh in ten years as it does now. Due to the declining carbon intensity of the grid however, these devices will become more "emissions efficient" over time; the electric vehicle will emit less CO_2 per mile in ten years than it does today. Moreover, both electric vehicles and electric water heaters can be flexibly managed to charge when low-cost or renewable energy is available, providing additional opportunity to secure economic and environmental benefits.

8. The Electric Utility Workforce is Rapidly and Dynamically Changing in Terms of Talent Requirements, Diversity, and Generational Needs

8.1. Electric Cooperatives are Finding it Challenging to Attract and Retain the Talent Needed to Provide Safe, Reliable, Affordable, and Sustainable Electricity

The electric co-ops employ approximately 76,000 employees in primarily rural America. These employees are operating in a world of rapid change in terms of policy, technology and member sophistication. Industry drivers such as:

- The consumer-centric energy market;
- Integrating intermittent energy resources; and
- Future developments in storage, transmission capability and automation.

All impact the talent needed from the front office staff to the engineers to the board rooms. Co-ops are observing a dynamically changing workforce in terms of talent requirements, diversity and generational needs. As we look to the future:

- 50% of distribution co-op CEOs will be eligible to retire between now and 2020.
- 72% CEOs will be eligible to retire by 2025.

These are staggering numbers. Some organizations have multiple layers of retirements – including board members, the CEO, and senior management – all of which create potential leadership gaps. Co-ops are working to ensure their next generation of leadership is ready to step into the vacancies and when necessary have access to the external talent needed to fill critical positions.

As our distribution, generation and transmission systems consider how to attract and retain their next workforce, what has been learned is the talent pool to draw from is shrinking. There are a few pressures causing this:

- Energy Industry jobs rate #23 out of 25 based on a survey of college students.
- The shrinking of rural America:
    - In 2000, 17.3% of Americans lived in rural counties. By 2010, that # dropped to 16.4%.

    - "Bright Flight" – Younger generations are moving to the cities.
- Competition for resources is not just local, it is global and it is fierce.

Add to these pressures the economic development challenges faced by many rural counties across the country and it creates a dynamic that is challenging for co-ops to attract and retain the talent needed to provide safe, reliable electricity to their members and a reasonable cost.

8.2. The Changing Nature of Employment in Rural America is Exacerbated by a Serious Job/Skills Mismatch

It is inaccurate to claim that all rural areas will have employment opportunities in the new economy; it would be equally misleading to assert that all rural areas will struggle. The challenge is the changing nature of employment in many parts of rural America and a serious "job/skills mismatch." Workers do not have the right skills to obtain the high wage jobs available in the new economy.

There is no simple solution to these challenges. Long-term strategies should focus on strengthening rural educational systems to improve the academic performance of rural youth, as well as recruitment initiatives to attract new entrepreneurs to rural communities. Short-term strategies should involve public-private collaboration on job training and placement programs tailored to the needs of both job seekers and local employers.

Access to training and supportive services is one of the greatest challenges confronting rural job seekers. Access takes on added levels of meaning in rural America, where it also encompasses geography and chronic poverty.

- Most rural areas are characterized by low population density. Distance from training facilities or job placement offices may be a barrier for some, while lack of access to online resources and distance learning technology poses barriers for others.
- Many causes of rural poverty are the same as in urban areas, including economic restructuring, loss of older industries, inadequate skill levels in the labor pool, lingering discrimination and the prevalence of low-income single parent families. Unlike urban areas, the rural setting diminishes the variety of wages of available jobs, reduces the incentives to

get education or training and creates significant barriers for those who rely on public transportation.

Education and training professionals recognize that many of the best solutions will come from collaboration and partnerships that involve private employers, workforce development professionals, educational institutions and community and economic development organizations.

8.3. The Risk and Uncertainty Behind Workforce Changes is Impacting the Ability of Electric Cooperatives to Create a Sustainable Talent Pipeline of Qualified and Diverse Workers

In partnership with the Center for Energy Workforce Development (CEWD), NRECA has identified industry game changers such as infrastructure modernization, cleaner energy mix, new builds, regulation / policy changes and physical / cyber security that represent a significant shift in operations that are impacting the size, skills and knowledge requirements of the current and future co-op workforce. The risk and uncertainty behind these changes can impact the ability of co-ops to create a sustainable talent pipeline of qualified and diverse workers leading to a risk of being able to provide safe, reliable and affordable power to co-op members.

Although much has been done to analyze the impact of the aging workforce, the workforce implications of these industry game changers may have as great or greater influence. As workers retire in one area, their replacements may be hired in another because the generation mix at the co-op changes, or as new technology changes the skills required for new employees changes as well. The risks can be significant if the industry does not have the right number of workers with the right skills at the right time and in the right place. Risks associated with these issues include financial, knowledge, safety, and timing.

One of the most difficult aspects of workforce development is balancing the supply of qualified workers with specific industry demand. From a skills perspective, CEWD views engineering as a significant risk. The need for degreed engineers to design new infrastructure is only expected to grow and the skill requirements are changing. The need also precedes other jobs as engineers are needed to design the work before it can be built. In addition, the results of the CEWD Gaps in the Energy Workforce Pipeline Survey show a significant decrease in the number of mid-career engineers that could reflect a knowledge risk as older engineers retire and new engineers enter the workforce.

Generation Technicians and Plant / Field Operators are most impacted by the changes to a cleaner energy mix and new build. As some plants are closing and others are built, skill requirements, workforce size and location will shift as well. Generation technicians are also the most at risk for retirements as well as potential generation shifts have caused many technicians to delay retirements.

The skills impact from the cyber / physical security requirements is different. While it's unlikely that a large number of physical/cyber security jobs are going to be created by the industry, the issue is less about numbers and more about adequate coverage and expertise. The industry can't afford not to have their employees adequately trained and aware of cyber threats, in the control rooms and beyond. The potential for cyber and physical threats and appropriate actions must be understood by all employees, much like safety education.

Ensuring the availability of talent for these core areas, in rural America, is a challenge our co-ops face every day, NRECA is supporting through our Next Generation Workforce initiative and one we believe the Department of Energy can continue to support and do more in the future through the Job Strategy Council and other programs it has in place.

8.4. NRECA is Building a Diverse Community of Co-op Members to Engage in Helping Identify, Develop, and Share Creative and Practical Solutions to Workforce Development Challenges

NRECA's Strategic Plan includes a Next Generation Workforce goal, which is to:

> *Enable cooperatives to attract, develop and retain the best, brightest and best matched talent for today and the future.*

Since 2014, NRECA has been working closely with our members to build our capacity as well as our members to respond to the next generation workforce challenge. Through national co-op programs we are building a diverse community of co-op members who network and engage in helping themselves and co-op network in identifying, developing and sharing creative, practical solutions to our workforce development challenges. A couple of these programs include:

- **Serve our Co-ops; Serve our Country.** Serve our Co-ops; Serve our Country is a nationwide electric co-op initiative to honor and employ veterans, military service members, and their spouses. The program focuses on educating and training co-ops to implement nationally recognized leading practices in attracting, hiring, onboarding and retaining veterans. Co-ops from 47 states are called to form a national coalition with the shared goal of employing veterans and setting them for success. The second focus area of this program is to care for the veteran communities that live in suburban and rural areas. Co-ops are called to engage with local initiatives to enhance veterans' integration within their communities and promote available resources to veterans. Learn more at: www.servevets.coop.
- **DOE GEARED Program.** Through the U.S. Department of Energy's SunShot Initiative, the Grid Engineering for Accelerated Renewable Energy Deployment (GEARED) program was created late in 2013 to build a training and education framework that grows the expertise and preparedness of current and future electric utility sector professionals – specifically to accommodate high penetrations of solar electricity and other distributed technologies. NRECA is developing course material appropriate for field technicians and engineers, and NRECA's network of co-ops is providing a real-time test bed for the courses through several dissemination channels. NRECA is also organizing workshops and short courses (PDHs or CEUs) that target current practitioners.
- **National Electric Cooperative Mentoring Program.** The National Electric Cooperative Mentoring Program is designed to help co-ops retain their top talent and prepare their new employees for current or future responsibilities. Mentors are one resource to help employees acclimate to their new job responsibilities, decrease their learning curve and build their national cooperative network. The program fosters collaboration and cooperation among cooperatives and exposes participants to new ideas and approaches in their respective functional areas. The program is national in scope; connecting Mentors and Mentees from different co-ops and different parts of the country.

- **Next Generation Leaders Program.** The inaugural Next Generation Leaders program was launched in February of 2016 to create the opportunity for emerging co-op leaders from all disciplines to meet, innovate and lead the next greatest thing across the cooperative network. The program helps a) to develop emerging cooperative leaders through learning opportunities, collaboration and building their professional networks b) participants build an appreciation for the cooperative business model and the reach of the electric co-op network and c) enable year-round interaction between the participants.
- **National Recruiting Initiative.** NRECA continually participates in activities that promote not only the national network of electric co-ops, but also other energy industry partners. It is important to us that our nation's youth, college students and adults are aware of the utility industry, see it is an exciting place to work, and take action to obtain the training needed to fulfill our jobs.

NRECA has demonstrated a strong commitment to educating and engaging job seekers about energy jobs and more specifically co-op jobs. We appreciate and look to expand our partnership with the Department of Energy as well as other federal agencies such as the Department of Labor, the Department of Agriculture, and other federal and state organizations focused on job expansion in rural America.

Recommendations

1. DOE Should Continue Programs Like the Utility Industry Workforce Initiative and GEARED.

Programs that create training and education frameworks that grow the expertise and preparedness of current and future electric utility sector professionals should be continued and expanded to address other workforce challenges in the electric utility industry.

2. DOE Should Continue to Provide Grants that Encourage the Development of Curriculum Needed by Utilities.

There is an aging workforce in our colleges and universities which creates a risk for having educators that can teach not only the competencies need to support new technologies, but can also maintain our older ones as well.

3. DOE Should Focus on Improving the Image of Energy Jobs at the High School and College Level.

Improving the image of energy jobs, particularly at the high school and college levels, can help in recruiting students into the needed fields as well as help attract and retain professors that can teach the content.

4. DOE Should Explore Opportunities in Convening a Higher Education Consortium to Explore Ways in Addressing Workforce Shortages in the Energy Industry.

The surprising turnaround in the nursing workforce over the past decade provides a model for potential solutions to the workforce shortages in the energy industry. DOE could use its "bully pulpit" to bring together energy trade associations and stakeholders with healthcare trade associations to explore how the healthcare industry encouraged the sharp increase in interest in nursing as a career, and potential lessons learned that the energy industry can incorporate into its efforts.