Attachments

Attachment A

2012 NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

COMMENTS OF
CLEAN LINE ENERGY PARTNERS LLC

January 31, 2012

UNITED STATES OF AMERICA
UNITED STATES DEPARTMENT OF ENERGY
OFFICE OF ELECTRICITY DELIVERY AND ENERGY RELIABILITY

2012 NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

COMMENTS OF
CLEAN LINE ENERGY PARTNERS LLC

January 31, 2012

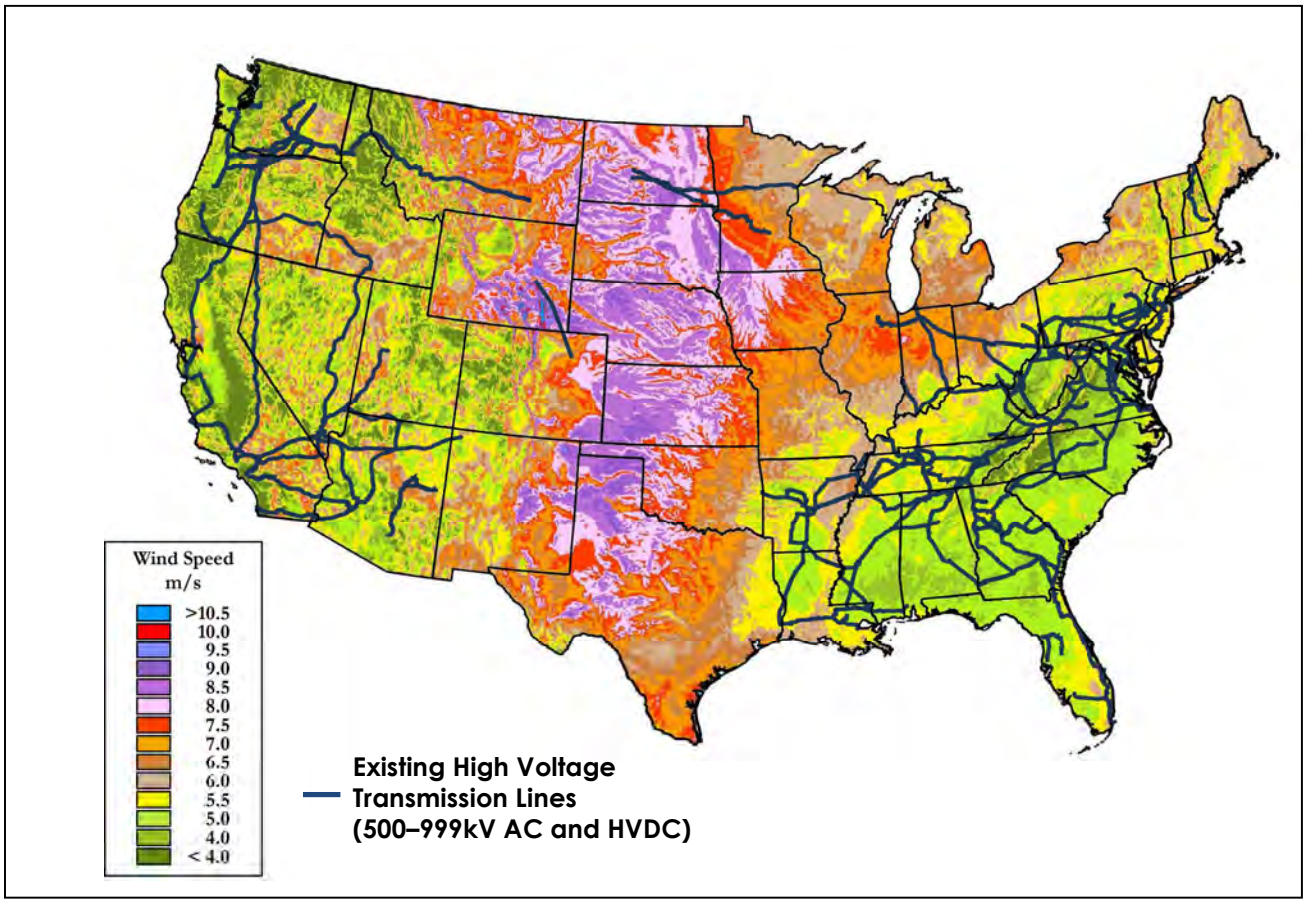
Clean Line Energy Partners LLC ("Clean Line") respectfully submits these comments in response to the Department of Energy's ("DOE") Plan for Conduct of 2012 Electric Transmission Congestion Study ("Congestion Study") as published in the Federal Register on November 11, 2011. Clean Line appreciates the DOE's renewed efforts to gather and review existing and new transmission data across the nation (as per 76 FR 70122) to develop a list of congestion areas that may be eligible for backstop authority under 216a of the Federal Power Act.

Clean Line submits the attached comments for consideration.

Background

Clean Line is an independent developer of four long-haul, high voltage direct current ("HVDC") transmission lines across the United States. Clean Line focuses exclusively on connecting the best renewable energy resources in North America with robust electricity demand centers. It hopes to play an instrumental role in expanding much needed transmission capacity and accelerating the delivery of renewable energy throughout the U.S. The need for lines like those that Clean Line is developing will continue to grow as electricity demand increases in the United States and as the demand for clean power sources accelerates. Technology improvements in wind and transmission make the efficient transportation of wind energy more feasible now than ever before.

Figure 1
Best Wind Resources Are Located Far From Existing High Voltage Grid



Source: Wind speed map – NREL and AWS Truepower[1]
High Voltage Transmission lines map – Platts POWERMap[2]

As Clean Line noted in our comments to the 2009 Congestion Study, we urge DOE to consider additional National Interest Electric Corridor (NIETC) designations in order to relieve congestion associated with the wind Conditional Congestion Area in the East. New transmission in these regions will ensure that existing congestion is eliminated and that there is enough additional capacity to allow new renewable resources to serve distant loads.

Furthermore, Clean Line believes that the Department of Energy (DOE), as an administration priority, should encourage transmission developers to propose corridors to be

[1] www.nrel.gov/wind/resource_assessment.html
[2] www.maps.platts.com

considered for designation, especially in areas that will promote renewable energy development. If DOE does allow developers to request corridors, it should be incumbent on the developer to provide evidence of the congestion and DOE should complete its review of the proposed corridors within a reasonable period of time. Providing timely answers to developers is critical to ensuring that the capital necessary to upgrade our aging transmission system is deployed efficiently.

Transmission Facilitates Renewables Integration

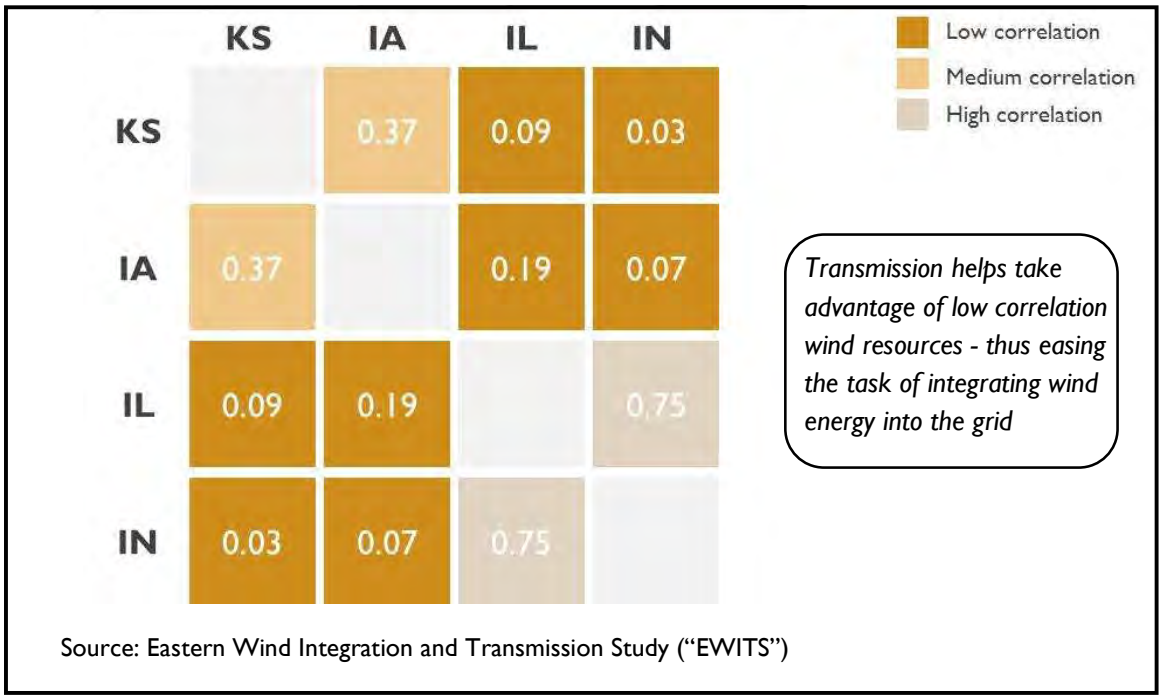
New transmission is required to facilitate increased integration of renewable energy into the nation's grid, both to meet state renewable portfolio standards ("RPS") and to tap into the vast low-cost wind energy resources available in the Great Plains. For example, the Eastern Interconnect Planning Collaborative ("EIPC"), a DOE-funded initiative that is preparing analyses of transmission requirements in the Eastern Interconnect under a range of alternative futures and developing long-term interconnection-wide transmission expansion plans in response to them, has selected three scenarios to be modeled in greater detail in Phase II[3], two of which involve a significant transmission build-out eastwards from the Great Plains.

Tapping into diverse wind resources will ease the integration of wind energy into a given RTO. For example, sourcing a portion of the wind energy required to meet the PJM states' RPS requirements from the Great Plains (for instance, from Iowa and Kansas) would lower the cost of integrating large amounts of wind energy. This is because the Great Plains wind is relatively uncorrelated with wind within PJM states (for instance, from Illinois and Indiana) – that is, wind blows in Iowa and Kansas when it is not blowing in Illinois and Indiana and vice

[3] EIPC Phase I Report, http://www.eipconline.com/uploads/Phase_I_Report_Final_12-15-2011.pdf

versa; hence a combined wind output of wind energy from these 4 states would be relatively stable and hence easier for PJM to integrate into its system.

Figure 2
Correlation of 10-Minute Wind Energy Generated[4]



Source: Eastern Wind Integration and Transmission Study ("EWITS")

The southeast requires a significant amount of new transmission in response to increased demand for renewable energy. A study conducted by Oak Ridge National Laboratory in 2009[5] to assess the power transfer potential to the southeast in response to a federal RPS mandate or CO2 policy found wind energy transfers at the level of 30-60 GW to be required in to the region, which would require large amounts of new transmission. Existing wind energy contracts by utilities in the southeast are already facing transmission constraints. To cite an example, in its application with the Alabama Public Service Commission to enter into a 202

[4] http://www.nrel.gov/wind/systemsintegration/ewits.html
"Low correlation": between 0.0 and 0.25; "Medium correlation": between 0.25 and 0.5; "High correlation": between 0.5 and 1.0
Sites selected: KS: #62, IA: #367, IL: #3693, IN: #3579

5 "Power Transfer Potential to the Southeast in Response to a Renewable Portfolio Standard: Final Report", http://info.ornl.gov/sites/publications/files/Pub21494.pdf

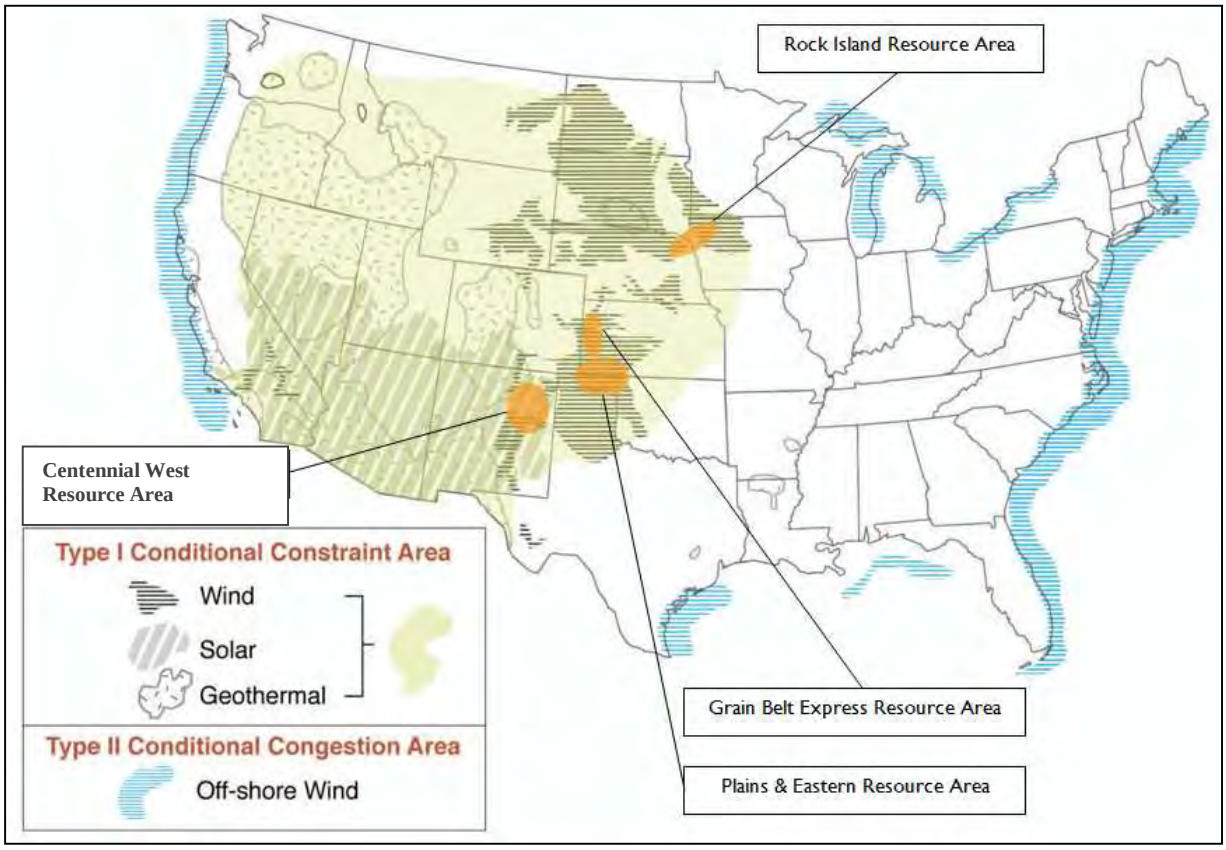
MW wind power purchase agreement ("PPA") with the Chisholm View Wind Project in central Oklahoma, Alabama Power emphasized that the Chisholm View project "requires the procurement of transmission to effectuate energy delivery of the project's output through Entergy and SPP balancing authority areas. Accordingly, the actual guaranteed energy deliveries ultimately are a function of the amount of transmission service procured."[6]

Transmission Could Stimulate Economic Activity in Renewables-Rich States

In the 2009 Congestion Study, DOE notes that the development of additional wind resources in Kansas and Oklahoma could improve the economic vitality of the states' rural counties, enhance reliability, and potentially reduce electricity costs to consumers, all of which would not be possible without additional transmission capacity. Each of the HVDC lines that Clean Line is developing begins in a resource region that DOE has designated as a Type 1 Conditional Constraint Area for wind resources, as noted in Figure 3. Additional available transmission capacity in these areas will enable new renewable resources to be developed to serve the load centers in the eastern and southeastern United States.

6 Pg. 4 of Petition for a Certificate of Convenience and Necessity by Alabama Power Company, dated June 10, 2011.

Figure 3
Type I and Type II CCA's with Clean Line Origination Points



Source: National Electric Transmission Congestion Study, December 2009. US Department of Energy

As discussed below, there is additional evidence of congestion that DOE should consider when it designates future Critical Congestion Areas and NIETCs.

Significant Transmission Upgrades Are Needed to Relieve Congestion in Western SPP

There is a present need for transmission that enhances the ability of power to flow from western SPP, where the richest wind resource is located, eastward to locations with high

electricity demand. In the SPP WITF Wind Integration Study[7] commissioned by SPP, Charles River Associates finds that as more wind is installed, "power flows from western SPP to eastern SPP increase significantly." The study continues, stating "[t]o accommodate the increased West-to-East flows while meeting the reliability standards of the SPP Criteria, a number of transmission expansions were required."[8] In the absence of new transmission, generation will continue to be curtailed in SPP, as noted below, and renewable development will be halted due to the inability to move power to load centers.

Table 1
Curtailments in Southwestern Public Service ("SPS") Zone[9]

Price Level ($/MWh)	2009 Hours
<0	26
0 to 10	51
10 to 20	1,649
Total	1,726
Percent of Year	19.7%

Since SPP can use only a fraction of its vast renewable energy potential, fully tapping its potential will require additional export capability to the Southeast, which is not well endowed with renewable energy resources. SPP borders the Electric Reliability Council of Texas ("ERCOT") to the South, the Western Electricity Coordinating Council ("WECC") to the West, and the Midwest ISO ("MISO") and Entergy to the East. Because SPP's electrical frequency is asynchronous with ERCOT's and WECC's frequencies, the ability to export to these neighboring regions is constrained. SPP's Wind Integration Study found that "[a] concern is that SPP has limited DC connections with ERCOT (to the south) and WECC (to the west)."[10]

[7] SPP WITF Wind Integration Study, http://www.crai.com/News/listingdetails.aspx?id=12090.
[8] SPP WITF Wind Integration Study, 20, 1-2.
[9] SPS Zone is the most congested zone in the SPP. Clean Line's Plains & Eastern project will likely originate from within this zone, thus helping reduce congestion.
[10] SPP WITF Wind Integration Study, 30.

Exports to the East and West appear to be most promising to realizing SPP's wind potential, but only if transmission lines are developed to efficiently export power over long distances.

As DOE is aware, SPP is in the process of implementing significant upgrades to its AC transmission system. SPP's Board of Directors approved their "Priority Projects" to relieve congestion, improve SPP's generation interconnection queue, and enhance transfer capability from SPP West to SPP East. The Priority Projects will heighten the ability of wind farms to transmit power *within* SPP. However, additional transmission capacity is needed to increase the ability to export wind power *out* of SPP. The combination of SPP "Priority Projects" and additional export capability is needed to capitalize on the rich wind resources in SPP.

Table 2
Wind Capacity Potential by State

Windy Land Area >= 40% Gross Capacity							
		Factor at 80m				Wind Energy Potential	
Ranking (by Capacity Potential)	State	Total (km^2)	Excluded (km^2)	Available (km^2)	Available % of State	Installed Capacity (MW)	Annual Generation (GWh)
1	**Texas**	**180,822**	**15,426**	**165,397**	**24%**	**826,983**	**3,240,930**
2	Nebraska	165,445	10,012	155,433	78%	777,165	3,084,090
3	South Dakota	163,281	10,004	153,277	77%	766,383	3,039,460
4	**Kansas**	**163,170**	**11,105**	**152,065**	**71%**	**760,324**	**3,024,280**
5	North Dakota	160,497	21,932	138,564	76%	692,821	2,728,620
6	Montana	98,309	18,737	79,571	21%	397,857	1,529,560
7	Iowa	72,119	8,400	63,719	44%	318,595	1,232,860
8	Wyoming	70,268	17,787	52,482	21%	262,410	1,043,890
9	**Oklahoma**	**55,593**	**6,038**	**49,555**	**27%**	**247,773**	**952,678**
10	New Mexico	39,573.80	2,424.70	37,149.10	11.80%	185,745.30	712,877

Source: NREL and AWS Truepower[11]

As noted in Table 2 above, Oklahoma, Kansas and Texas are all ranked in the top ten in wind capacity potential. Each state has significantly more potential than the capacity of the SPP market. Developers are advancing projects totaling tens of thousands of MW in the Resource Area. Over 23,800 MW of wind projects are in the SPP Generation Interconnection Queue.

[11] www.nrel.gov/wind/resource_assessment.html.

Of these projects, 21,265 MW are located in the tri-state region of Kansas, Oklahoma, and Texas (only the northern part of the Texas panhandle is located in SPP). Many of these project will not be completed because there in not enough transmission capacity to export power to other load centers.

Table 3
Wind Projects in SPP Generation Interconnection Queue

SPP State	Wind Projects in SPP Generation Interconnection Queue (MW)
Kansas	9,577
Oklahoma	7,448
Texas	4,240
Nebraska	1,244
Missouri	962
New Mexico	360
Arkansas	0
Louisiana	0
TOTAL	**23,831**

Source: SPP Generation Interconnection Queue[12]

Additional Transmission is Needed to Import Power into the Southeast

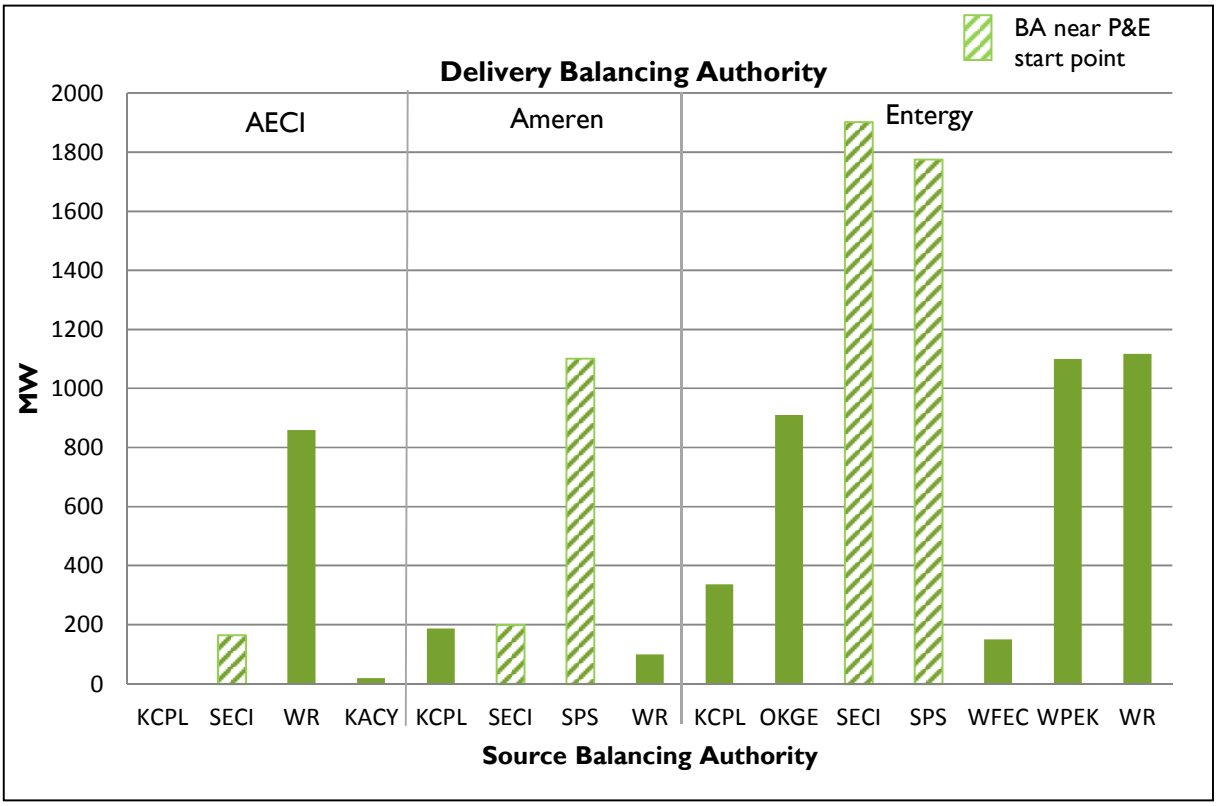
Transmission Service Requests ("TSRs") in SPP also reveal a significant demand to transmit power generated in western SPP to regions east of SPP. Because the great majority of new generation in SPP is wind power, a significant portion of these requests likely come from wind generation projects, which are searching for a way to reach markets east of SPP. Figure 4 below illustrates that as of January 13, 2012 there are nearly 10,000 MW of TSRs from western SPP regions to balancing authorities east of the SPP footprint. More specifically, there are more

[12] https://studies.spp.org/SPPGeneration/GI_ActiveRequests.cfm.

than 5,000 MW of TSRs from balancing authorities in proximity to the Plains & Eastern Clean Line's ("P&E") western terminal to regions east and south of SPP.

Figure 4

Transmission Service Requests from Western SPP to the East/Southeast



Source: SPP OASIS[13]

Western Interconnection

As noted above, Clean Line is developing the Centennial West Clean Line from Eastern New Mexico to the Arizona and California region. This region has been identified by western planning organizations as a major area of concern in the West. The DOE's 2006 Congestion study identified Southern California (spanning the metropolitan areas of Los Angeles and San

[13] http://www.oatioasis.com/spp_default.html.

Diego) and three counties in Arizona as a Critical Congestion Area. DOE later designated this area a National Interest Electric Transmission Corridor ("NIETC"), making this region eligible for FERC backstop siting authority. Clean Line agrees with this corridor designation but urges DOE to expand this designation to allow for imports of renewable energy.

This area has a history of congestion due to the large amount of imports across the region. Clean Line expects this congestion to increase as additional renewable wind resources are developed in eastern New Mexico and as solar resources are developed in Arizona. To meet the growing demand for electricity in the California market, Clean Line suggests that DOE consider designating the northern counties in Arizona, southern Nevada and much of New Mexico as Critical Congestion Areas and NIETCs.

Numerous transmission projects are in the planning and permitting phases of development. The failure of these projects could jeopardize reliability in the Western Interconnection and dramatically increase power prices in the Southwest region.

Clean Line participates in regional and sub-regional transmission planning activities in the Western Interconnection. WECC has led transmission planning efforts in the West for many years, highlighting congestion and identifying areas that may jeopardize reliability and cost consumers millions of dollars in wholesale energy costs. Clean Line urges DOE to work closely with WECC and the other transmission planning organizations in the West to consider the impacts of existing congestion on renewable energy development and the ability to that move power to major load centers. Designating additional constrained areas as Critical Congestion Areas and as NIETCs will help ensure that new transmission gets built.

State Laws

Finally, Clean Line urges DOE to evaluate all lower 48 state laws to determine if independent transmission developers can qualify to become public utilities and build transmission and determine other requirements at the state level needed to site, construct and operate transmission facilities. DOE must consider designating NIETC's in states that prohibit new entrants in the transmission business because they do not serve local load or impose other barriers to entry.

Conclusion

Clean Line appreciates the opportunity to provide comments for the DOE's consideration and also supports the comments of the American Wind Energy Association. We urge the DOE to expeditiously complete the 2012 Congestion Study process with a goal of ensuring that additional renewable resources are not constrained by lack of transmission and that corridors are designated expeditiously.

Respectfully submitted,

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Attachment B

DOE Quadrennial Report, Chapter 3


A
B
C

Chapter III

MODERNIZING THE ELECTRIC GRID

This chapter examines how the electricity grid of the future can provide affordable and reliable clean electricity, while minimizing further human contributions to climate change. After an introduction to the structure of the U.S. electrical grid, the chapter lays out a vision for its transformation and describes the drivers of change toward the future grid. These major drivers cover challenges and opportunities that affect transmission and distribution grids, involve new technologies and services, and require careful consideration of the diverse institutions and business models currently involved in managing the grid. After discussion of a policy framework for the grid of the future, the chapter concludes by presenting a series of recommendations, divided into three major categories: (1) research and development, analysis, and other studies; (2) state and regional planning and managing across jurisdictions; and (3) appropriate valuation, standards, and measurement methods to facilitate the introduction of new technologies and practices to improve the grid.

FINDINGS IN BRIEF:
Modernizing the Electric Grid

Investments in transmission and distribution upgrades and expansions will grow. It is anticipated that in the next two decades, large transmission and distribution investments will be made to replace aging infrastructure; maintain reliability; enable market efficiencies; and aid in meeting policy objectives, such as greenhouse gas reduction and state renewable energy goals.

Both long-distance transmission and distributed energy resources can enable lower-carbon electricity. The transmission network can enable connection to high-quality renewables and other lower-carbon resources far from load centers; distributed energy resources can provide local low-carbon power and efficiency.

The potential range of new transmission construction is within historic investment magnitudes. Under nearly all scenarios analyzed for the Quadrennial Energy Review, circuit-miles of transmission added through 2030 are roughly equal to those needed under the base case. And while those base-case transmission needs are significant, they do not appear to exceed historical yearly build rates.

Flexible grid system operations and demand response can enable renewables and reduce the need for new bulk-power-level infrastructure. End-use efficiency, demand response, storage, and distributed generation can reduce the expected costs of new transmission investment.

Investments in resilience have multiple benefits. Investments in energy efficiency, smart grid technologies, storage, and distributed generation can contribute to enhanced resiliency and reduced pollution, as well as provide operational flexibility for grid operators.

Innovative technologies have significant value for the electricity system. New technologies and data applications are enabling new services and customer choices. These hold the promise of improving consumer experience, promoting innovation, and increasing revenues beyond the sale of electric kilowatt-hours.

Enhancing the communication to customer devices that control demand or generate power will improve the efficiency and reliability of the electric grid. For example, open interoperability standards for customer devices and modified standards for inverters will improve the operation of the grid.

Appropriate valuation of new services and technologies and energy efficiency can provide options for the utility business model. Accurate characterization and valuation of services provided to the grid by new technologies can contribute to clearer price signals to consumers and infrastructure owners, ensuring affordability, sustainability, and reliability in a rapidly evolving electricity system.

Consistent measurement and evaluation of energy efficiency is essential for enhancing resilience and avoiding new transmission and distribution infrastructure. Efficiency programs have achieved significant energy savings, but using standard evaluation, measurement, and verification standards, like those recommended by the Department of Energy's Uniform Methods Project, is key to ensuring that all the benefits of efficiency are realized, including avoiding the expense of building new infrastructure.

States are the test beds for the evolution of the grid of the future. Innovative policies at the state level that reflect differences in resource mix and priorities can inform Federal approaches.

Different business models and utility structures rule out "One-Size-Fits-All" solutions to challenges. A range of entities finance, plan, and operate the grid. Policies to provide consumers with affordable and reliable electricity must take into account the variety of business models for investing, owning, and operating grid infrastructure.

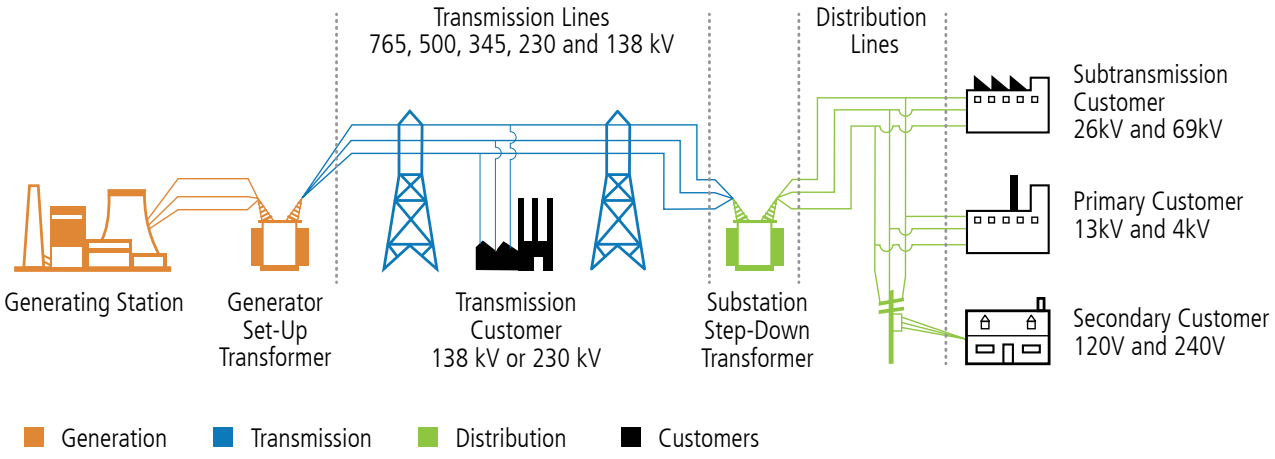
Growing jurisdictional overlap impedes development of the grid of the future. Federal and state jurisdiction over electric services are increasingly interacting and overlapping.

The Electric Grid in Transition

The United States has one of the world's most reliable, affordable, and increasingly clean electric systems—a system that powers its economy and provides for the well-being of its citizens. The U.S. electric system is at a strategic inflection point—a time of significant change for a system that has had relatively stable rules of the road for nearly a century.

The structure of today's U.S. electric grid grew organically over the course of the last century (see Figure 3-1). Historically, it was geographically based—with one-way flows of energy from central station generators, over transmission networks, through substations to distribution systems, and over radial distribution circuits to end-use customers.

Figure 3-1. The Electric Grid[1]



Six components comprise the grid: four physical components, including generation, transmission, distribution, and storage; the information infrastructure to monitor and coordinate the production and delivery of power and operate the grid; and customer demand—the driver of power system operation and investment. New storage technologies could be deployed throughout the power system in the future.

The U.S. electricity sector is influenced by a variety of new forces, some of which will affect the future growth and management of the grid. Current drivers of change within the electricity sector include the growing use of natural gas to power electricity generation; low load growth; increasing deployment of renewable energy and the retirement of coal and nuclear generation; severe weather and climate change; and growing jurisdictional interactions at Federal, state, and local levels. Innovative technologies and services are being introduced to the system at an unprecedented rate, often increasing efficiency, reliability, and the roles of customers, but also injecting uncertainty into grid operations, traditional regulatory structures, and utility business models.

The changing nature of grid operations, the implications of demand response and distributed generation deployment at increasing scale, the introduction of other new technologies, and growing consumer interaction with the grid are putting pressure on the regulatory boundaries that have evolved over the past century. Resolving the institutional, regulatory, and business model issues that could enable the grid of the future will help the United States take full advantage of the range of available energy sources and technologies that will help meet its climate change goals. These sources and technologies include energy efficiency; energy storage; carbon capture, utilization, and storage; electric vehicles; microgrids and other distributed technologies; and nuclear, natural gas, and renewable energy generation. A positive resolution of these issues will also help mitigate the growing vulnerabilities of the grid to cyber, physical, and climate change threats, as well as ensure the grid's reliability under its current institutional structures.

The Electric Grid: Complex, Highly Engineered, Essential for Modern Life

At the core of the electricity system is the grid—a complex, highly engineered network that coordinates the production and delivery of power to customers. There are six elements that make up the grid (see Figure 3-1)—four physical components of the electric system (generation, transmission, distribution, and storage); the information infrastructure to monitor and coordinate the production and delivery of power and operate the grid; and demand—the driver of power system operation and investment. Transmission, storage, and distribution (TS&D) provide the backbone of the grid, with storage increasingly deployed throughout the power system.

Today, the U.S. transmission and distribution system is a vast physical complex of interlocked machines and wires, with a correspondingly complex set of institutions overseeing and guiding it through policies, statutes, and regulations. The U.S. grid delivers approximately 3,857 terawatt-hours[2] of electrical energy from electric power generators to 159 million residential, commercial, and industrial customers.[a] This is accomplished via 19,000 individual generators at about 7,000 operational power plants in the United States with a nameplate generation capacity of at least 1 megawatt (MW).[3] These generators send electricity over 642,000 miles of high-voltage transmission lines and 6.3 million miles of distribution lines.[4] Together with its electric generation component, the grid is sometimes referred to as the world's largest machine; in 2000, the National Academy of Engineering named electrification as the greatest engineering achievement of the 20th century.[5]

Transmission is the high-voltage transfer of electric power from generating plants to electrical substations located near demand or load centers. As shown in Figure 3-1, step-down substations are the boundary between the transmission system and the distribution system that serve retail customers. High-voltage transmission lines can more easily accommodate two-way flows of electricity than the distribution network. High-voltage transmission lines have a range of voltage classes—mostly alternating current with some direct current. Transmission lines are primarily owned by investor-owned utilities and public power and cooperative-owned utilities within each interconnection. New forms of ownership of transmission assets, including independent transmission companies and "pure-play" merchant transmission firms, are beginning to emerge. For the new transmission-focused utilities, the core business and potential source of profits is based on acquiring, developing, building, and operating transmission.

Distribution is the delivery of power from the transmission system to the end users of electricity. Distribution substations connect to the transmission system and lower the transmission voltage to medium voltage. This medium-voltage power is carried on primary distribution lines, and after distribution transformers lower the voltage, secondary distribution lines carry the power to customers. Larger industrial customers may be connected directly at the primary distribution level. The poles supporting distribution lines, meters measuring usage, and related support systems are also considered to be part of the distribution system.

A Vision for the Grid of the Future

Today's grid—where power typically flows from central station power plants in one direction to consumers—is fundamentally different from the grid of the future, where two-way power flow will be common on both long-distance, high-voltage transmission lines and the local distribution network.

The grid of the future will be an essential element in achieving the broad goals of promoting affordable, reliable, clean electricity and doing so in a manner that minimizes further human contributions to climate change. To do this, the grid of the future will have to accommodate and rely on an increasingly wide mix of

[a] Here, a "customer" is defined as an entity that is consuming electricity at one electric meter. Thus, a customer may be a large factory, a commercial establishment, or a residence. A rough rule of thumb is that each residential electric meter serves 2.5 people.

resources, including central station and distributed generation[b] (some of it variable in nature), energy storage, and responsive load. It should support a highly distributed architecture that integrates the bulk electric and distribution systems. It should enable the operation of microgrids that range from individual buildings to multi-firm industrial parks and operate in both integrated and autonomous modes.

New technologies for the grid, including storage, will alter the traditional real-time requirements for grid operations and the nature of production, transmission, and distribution of power—opening up new avenues for flexible and cost-effective operation of the grid.

The grid of the future should be supported by a secure communication network—its information backbone—that will enable communication among all components of the grid, from generation to the customer level, and protect the system from cyber intrusions. This communication network will support the ability to monitor and control time-sensitive grid operations, including frequency and voltage; dispatch generation; analyze and diagnose threats to grid operations; fortify resilience by providing feedback that enables self-healing of disturbances on the grid; and evaluate data from sensors (such as phasor measurement units[c]) that enable the grid to maximize its overall capacity in a dynamic manner.

In short, the grid of the future should seamlessly integrate generation, storage, and flexible end use. It should promote greater reliability, resilience, safety, security, affordability, and enable renewable energy, while achieving better economic and environmental performance, including reductions in greenhouse gas (GHG) emissions. It will require business models and regulatory approaches that sustain grid investment and continued modernization while at the same time allow for innovation in both technologies and market structures.

The Department of Energy's (DOE's) Quadrennial Technology Review summarizes the technology challenges and research, development, and demonstration requirements for transforming the grid and achieving this vision. The Quadrennial Energy Review (QER) therefore focuses on the institutional, regulatory, and business model barriers to achieving the grid of the future.

Emerging Architecture of the Grid

The architecture of the grid is a new, emerging concept that defines the grid as not just a physical structure, but one that encompasses a range of actors and needs.[6] This new, broader concept of a grid architecture considers information systems, industry, regulators, and market structures; electric system structure and grid control frameworks; communications networks; data management structure; and many elements that exist outside the utility but interact with the grid, such as buildings, distributed energy resources, and microgrids. The grid's architecture is shaped by public policy, business models, historical and even cultural norms of practice, technology, and other factors. Analyses conducted for the QER (see box on page 3-6) focused on the complex interactions of these players and qualities, with the goal of suggesting recommendations to help drive toward a vision of actively shaping the grid of the future, as opposed to passively allowing the grid to evolve in a bottom-up manner and waiting to see the form that emerges. Analyses carried out for the QER also considered the drivers of change and how those drivers affect both today's grid and the future grid.

[b] There are a variety of options for distributed generation, including photovoltaics, wind, low-head hydropower, combined heat and power, and fuel cells.

[c] Phasor measurement units operate by the simultaneous measurement and comparison of an important electrical property of large-scale alternating current transmission networks known as "phasor angles," thus the name "phasor measurement units." This will provide valuable real-time early warning of potential grid problems, including over very large geographic regions, when the technology is fully deployed and related tools to use the information are implemented.

Electricity Transmission Scenario Analysis

Quadrennial Energy Review scenario analysis used the Regional Energy Deployment System model to determine the impact of varying 10 input assumptions, individually and in combination, on U.S. transmission needs (see Chapter I, Introduction, Table 1-2 for the complete list of cases). The majority of cases characterized clean energy futures, in which renewable energy costs (such as solar and wind) dropped dramatically, or a greenhouse gas cap drove low- and carbon-free electricity generation deployment. An accelerated nuclear retirement case looked at the effect of the rapid loss of baseload capacity and is discussed in depth in the Electricity Appendix. The Quadrennial Energy Review focused on these cases as most likely to "stress" the transmission system, as they would produce significant changes in the electricity sector, and thus large potential changes in transmission needs.

Under the Annual Energy Outlook 2014 Reference case, installed megawatt-miles of transmission infrastructure grew by 0.3–1.5 percent per year and 6 percent total through 2030. While there was a range of new installed transmission across the scenarios, none of the scenarios appeared to require additional buildout beyond that already anticipated in the 2030 timeframe, nor did rates in any scenario exceed recent historical transmission investment levels.

Drivers of Change for the Grid of the Future: Transmission and Distribution

While the architecture of the grid of the future extends well beyond the physical structure of the system, a discussion of the drivers of change for the grid of the future should start with a consideration of the changes that will likely affect both transmission and distribution systems. Both systems may continue to grow in physical size to meet new needs, including demands for lower carbon electricity, but investments to facilitate flexible operations and resilience can enable smart growth, so both transmission and distribution systems can serve customer needs more effectively and economically.

Investments in Transmission Are Expected to Grow

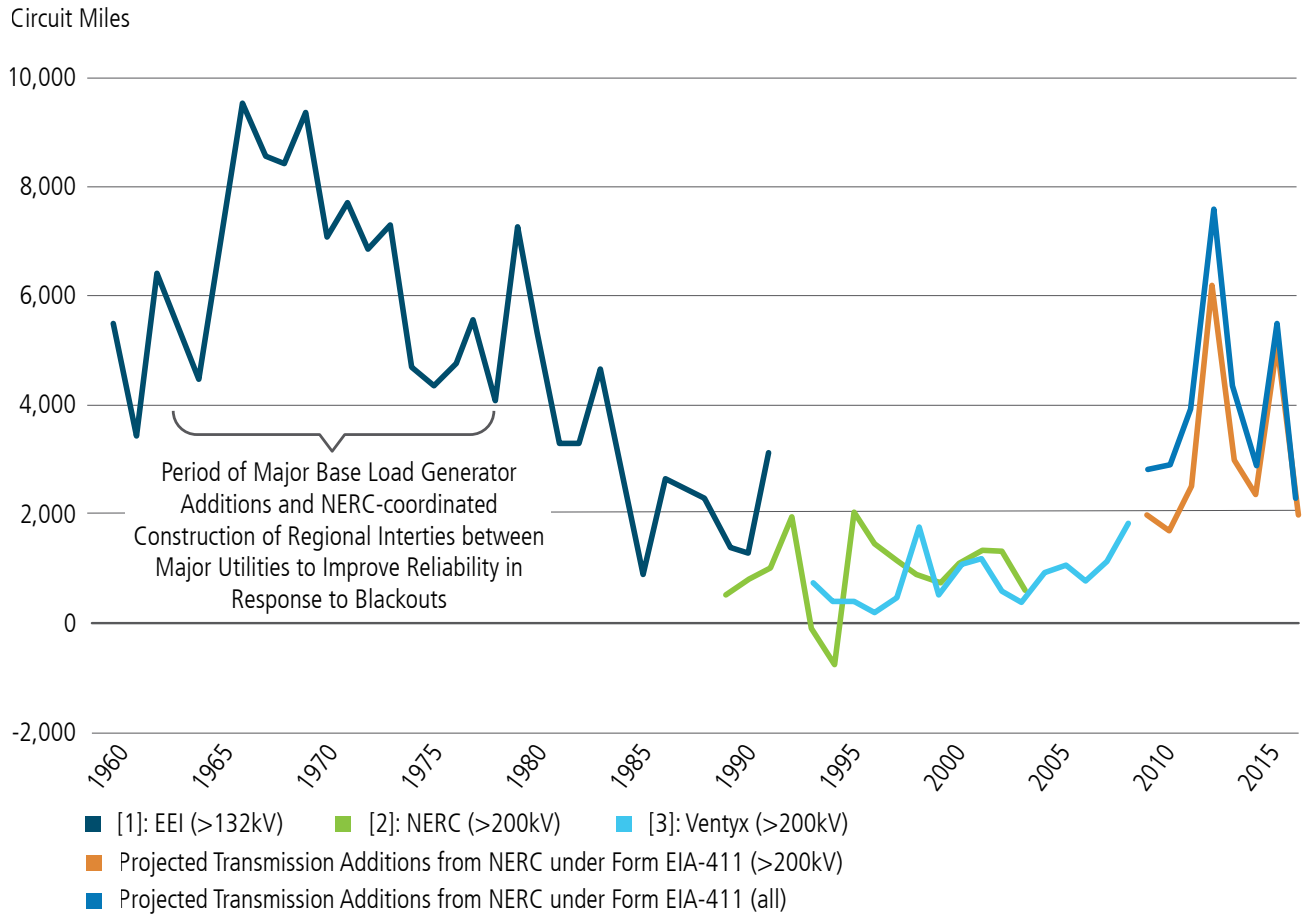
Transmission development and planning activity has been on the rise since the early 2000s, reversing a decades-long decline following the historic build-out of the transmission system in the mid-20th century. As an asset class, transmission attracts significant investment from utilities, financial investors, and project developers. Investor-owned utilities spent a record high of $16.9 billion on transmission in 2013,[7] up from $5.8 billion in 2001.[8] The number of circuit miles added to the Nation's transmission networks has also been on the rise in recent years (see Figure 3-2), but new line construction accounts for just slightly more than half of total investments.[9] Non-line investments—including station equipment, fixtures, towers and undergrounding lines—were increasing even during the lowest period of circuit miles construction from 1997 to 2012 (see Figure 3-3).

Drivers of recent investment increases include new technologies for improved system reliability; development of new infrastructure to ease congestion; interconnection of new sources of generation, including renewable resources; and support for production of natural gas. These investments have very distinct regional characteristics based on the different resources and constraints of each region.[10, 11] The largest increase in transmission spending over the last 15 years occurred in the Western Electricity Coordinating Council, with much of the transmission expansion happening in southern California to relieve constraints and connect to renewable resources.[12]

Looking forward over the next several years, a high level of transmission investment is expected to replace aging infrastructure; maintain system reliability; facilitate competitive wholesale power markets; and aid regions in meeting their public policy objectives, such as GHG reduction and renewable energy goals.[13] How much new transmission capacity is built in the future depends on a number of factors, including the amount of transmission necessary to connect high-quality wind, solar, and other energy resources to load centers; uncertainty about state and Federal incentives like the Production Tax Credit; flat or declining electricity

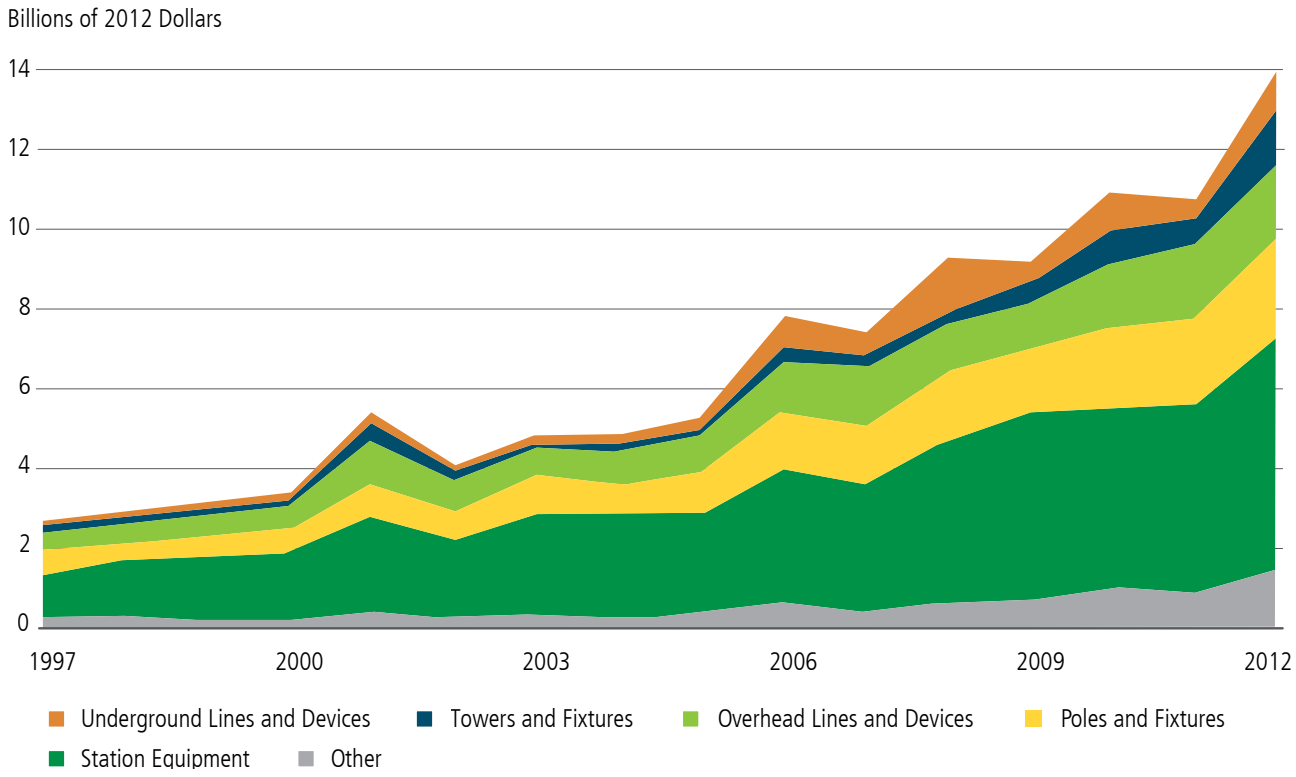
demand; and the costs of alternative generation and demand-side resources. For renewables, an additional uncertainty is whether time of permitting or the costs of additional transmission facilities may lead to the development of wind or solar resources that are of lower quality but closer to load (Appendix C, Electricity, includes a more in-depth discussion of transmission). Nevertheless, there are a number of long-distance interregional transmission lines now in various stages of market development.[14, 15]

Figure 3-2. Historic and Projected Expansion of Net Transmission Circuit Miles[16]



Addition of new circuit miles to the Nation's transmission system has increased in recent years after over a decade of lower build-out. This increase has been driven by investments to replace aging infrastructure; maintain system reliability; facilitate competitive wholesale power markets; and support public policy objectives, such as GHG reduction and renewable energy goals. Circuit miles constructed in a year vary more than total transmission infrastructure spending, which has had an upward trend since the late 1990s. Note that historical values are year to year reported net changes in total circuit miles.

Figure 3-3. Investment in Transmission Infrastructure by Investor-Owned Utilities, 1997–2012[17]



Spending on the various components of transmission infrastructure has steadily increased since the late 1990s, driven by factors ranging from the need to replace aging materials, to the development of new technology for increased reliability, to requirements to connect new generation.

Both Long-Distance Transmission and Distributed Energy Resources Can Enable Lower-Carbon Electricity

Both bulk and distributed technologies have the potential to supply low-carbon electricity, enhance system reliability, and operate at a reasonable cost for all consumers. High-quality renewable energy sources suitable for utility-scale generation facilities are often located in remote areas. New long-distance transmission lines may be necessary in the future to connect these resources to demand centers. Conversely, other factors, such as extensive deployment of distributed energy resources, could potentially reduce the need for additional long-distance transmission build-out in the future.

The analyses conducted for the QER examined transmission capacity needs in 2030 under a variety of scenarios (this analysis did not consider distribution line needs). One scenario considered in QER analyses modeled transmission capacity necessary to accommodate high deployment of low-cost distributed energy resources using low-cost solar photovoltaic (PV) as a proxy for all types of distributed generation. The results of scenario modeling show that changes in transmission requirements through 2030 for a high-distributed PV case vary by region. In most regions, 2030 transmission needs are similar to those for a scenario based on the Annual Energy Outlook 2014 Reference case—high deployment of very low-cost distributed energy resources does not eliminate the need for additional transmission capacity. In fact, transmission requirements in the Upper Midwest and Great Lakes regions increase slightly under the distributed PV scenario in order to optimize remaining baseload resources.

In the Southwest, transmission build-out requirements do, however, drop somewhat with expanded distributed PV because less utility-scale PV would be built in that region. This same effect is seen to a smaller extent in other Western regions. A review of three DOE-funded interconnection-wide studies, performed with American Recovery and Reinvestment Act of 2009 grants from 2012 to 2014, showed that scenarios combining high levels of end-use efficiency, demand response, and distributed generation can reduce the expected costs of new transmission investment. One 20-year scenario modeled in the Western Interconnection resulted in a reduction of $10 billion in transmission capital costs (or 36 percent below the base case).[18]

There are multiple technology innovations that could provide new long-distance transmission options. A serious physical challenge of high-voltage transmission lines is that the physics and safety factors require certain distances between the conducting wires and the ground and persons. Opponents of new transmission lines have called the resulting towers unsightly, intrusive, or "visual pollution." Ways to reduce additional issues with siting include the use of existing transmission line corridors, as well as technology fixes, such as higher-capacity-conducting materials, high-voltage underground lines, and even superconducting cables (also underground). Encouraging progress has been made on higher-capacity conductors that can be restrung on existing towers and on underground high-voltage direct current cables. These technologies should be considered and used when appropriate.

Flexible Grid System Operations and Demand Response Enable Variable Renewables and Reduce Need for New Infrastructure

All power systems have been designed with some level of flexibility to accommodate variable and uncertain load and contingencies related to network and conventional power plant outages. Flexibility is the ability of a resource—whether it is a component or a collection of components of the power system—to respond to the scheduled or unscheduled changes of power system conditions at various operational timescales (see Figure 3-4 for the timescale of different grid operations and planning functions).[19]

Figure 3-4. Transmission Operation and Planning Functions Shown by Timescale[20]

*Automatic Generation Control

Reliable and affordable electricity from the grid requires a continuum of operating, planning, and investment decisions over a wide-time horizon.

Grid operators must respond to trends affecting load patterns across a range of timescales, such as decreased demand growth, the changing demand patterns across the day, increased variable renewables, power plant retirements, and more extreme weather events. Many recent analyses lay out options for flexible electric systems.[21] Increased electric system flexibility can come from a portfolio of supply- and demand-side options, including grid storage, more responsive loads, changes in power system operations, larger balancing areas, flexible conventional generation, and new transmission.[22, 23]

Power Marketing Administrations: Valuable Federal Transmission Assets

Designed to provide customers access to electricity generated by Federal hydroelectric dams, the four Federal Power Marketing Administrations, along with the Tennessee Valley Authority, have a significant footprint within the North American grid. Today, in varying degrees, the operation, maintenance, and improvements to these Federal transmission assets are funded by revenues from and investments by preference customers. Honoring this unique customer-provider relationship, Congress has established two programs that build on the expertise of the Power Marketing Administrations. One is the Section 1222 program established by the Energy Policy Act of 2005 that authorizes the Department of Energy, through the Southwestern and/or Western Area Power Administrations, to partner with third parties to build transmission projects. There is one applicant proposing a line from wind resources in Oklahoma to Tennessee.[d] The other program is the Transmission Infrastructure Program established by the American Recovery and Reinvestment Act of 2009. The program allows the Western Area Power Administration to provide loans to and partner on transmission projects within its service area that support the development of renewable resources. The first Transmission Infrastructure Program project, the Montana to Alberta Tie Line, created 300 megawatts (MW) of transmission capacity specifically for renewable energy.[e] The project immediately enabled 189 MW to be deployed from the Rim Rock wind farm in Montana to markets.[f] The second project to be completed is Electrical District 5 – Palo Verde Hub. In this solar-rich area, the Electrical District 5 – Palo Verde Hub adds up to 410 MW of bi-directional capacity to the electric grid, including 254 MW of capacity connecting to the vital Palo Verde market hub that serves markets in Arizona, southern California, and Nevada.[g]

[d] Department of Energy. "Proposed Project: Plains and Eastern Clean Line." http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/transmission-planning/section-1222-0. Accessed February 1, 2015.

[e] Enbridge. "Montanar-Alberta Tie-Line." http://www.enbridge.com/DeliveringEnergy/Power-Transmission/Montana-Alberta-Tie-Line.aspx. Accessed February 1, 2015.

[f] NaturEner. "Rim Rock Wind Farm." http://www.naturener.us/rimrock. Accessed February 1, 2015.

[g] Western Area Power Administration. "Electrical District No. 5 - Palo Verde Hub Project." http://ww2.wapa.gov/sites/western/transmission/tip/project/pages/ed5pvh.aspx. Accessed February 1, 2015.

Demand Response

Demand response improves flexibility by enabling consumers to participate in load control; it could also reduce the need for new infrastructure. Demand response mechanisms can include automated load control, smart grid and smart metering, real-time pricing, and time-of-use tariffs. Demand response can be a cost-effective grid resource; though, it requires strict regulations for response time, minimum magnitude, reliability, and verifiability of demand-side resources. Experience in the Texas wholesale electricity system and, more recently, in California shows that market designs that include demand response participation can markedly improve system flexibility. For example, industrial customers supply a significant portion of the Electric Reliability Council of Texas's responsive (spinning) reserves and have demonstrated the ability to effectively respond within minutes to a dramatic change in wind output.[24]

Energy Storage

Energy storage technologies, including pumped hydro storage, thermal storage, hydrogen storage, and batteries provide valuable system flexibility. Storage is unique because it can take energy or power from the grid, add energy or power to the grid, and supply a wide range of grid services on short (sub-second) and long (hours) timescales. It can supply a variety of services simultaneously. For example, concentrating solar power paired with highly efficient thermal storage becomes a dispatchable resource (meaning grid operators can control the power output) available throughout the day. Many storage technologies (e.g., batteries, flywheels, and supercapacitors) have fast response rates (seconds to minutes) available over a short time frame; other storage technologies, such as compressed air energy storage, are better suited to offer flexibility in the time frame of hours to days. Pumped hydro storage is usable on a timescale from seconds to days.

Pumped hydro storage currently represents the largest share of storage in the United States, with 42 pumped hydro storage plants totaling about 22 gigawatts of installed capacity, which is equivalent to about 2 percent of U.S. electricity generation capacity.[25] There are currently an additional 37 gigawatts of projects that are in some stage of licensing at the Federal Energy Regulatory Commission (FERC).[26] The original pumped hydro storage plants were built to store power to release at peak demand. New technology (such as variable speed pumps) enable pumped hydro storage to provide ancillary services (i.e., functions that maintain the reliability of the grid); integrate variable renewables; and provide other services, such as restarting down generators during an outage. Under current market structures, options such as dispatchable natural gas are cheaper and faster to permit than pumped hydro storage. FERC has a pilot project underway to test a shorter 2-year licensing process for pumped hydro storage.

Federal and State Activities to Promote Storage

Department of Energy (DOE) support for valuation, early deployment, and education has contributed to storage adoption. For example, Federal Energy Regulatory Commission Order 755 cited a DOE lab study showing that "energy storage resources (such as flywheels and batteries) could be as much as 17 times more effective than conventional ramp-limited regulation resources" for providing frequency regulation.[h] The order requires payment for frequency regulation resources based on a resource's speed and accuracy,[i] resulting in significant growth of storage installations in markets such as PJM.[j] The recent DOE Energy Storage Safety Strategic Plan addresses institutional barriers to enhance the safety and reliability of storage.[k]

States have built on these advances to bring storage benefits to closer to the mainstream. California, home to multiple DOE-funded storage demonstrations,[l, m, n] has been aggressive with policies to promote storage, first with a program to incentivize behind-the-meter storage, and then with its storage mandate, which will require the state's three utilities to deploy 1,325 megawatts of storage by 2020.[o] In Hawaii, recent wind installations in Maui and Oahu have been paired with energy storage,[p] and Hawaiian Electric Company opened a solicitation for up to 200 MW of storage "to meet its goal of adding more renewable generation to the O'ahu grid."[q] Other states, including Arizona[r] and New York,[s] have approved or are actively encouraging their utilities to consider storage.

[h] Makarov, Y.V. et al. "Assessing the Value of Regulation Resources Based on Their Time Response Characteristics." Pacific Northwest National Laboratory. June 2008. In: 137 FERC 61,064. p. 35. 2011.

[i] Federal Energy Regulatory Commission. "Frequency Regulation Compensation in the Organized Wholesale Power Markets." 137 FERC 61,064. 2011.

[j] PJM Independent Market Monitor. "2013 State of the Market Report for PJM." p. 305. 2013.

[k] Department of Energy. "Energy Storage Safety Strategic Plan." December 2014. http://energy.gov/sites/prod/files/2014/12/f19/OE%20Safety%20Strategic%20Plan%20December%202014.pdf.

[l] Department of Energy. "Fact Sheet: Borrego Springs MicroGrid." September 2013. http://www.sgiclearinghouse.org/sites/default/files/projdocs/1650.pdf.

[m] Department of Energy. "Fact Sheet: Wind Firming EnergyFarm." August 2013. http://energy.gov/sites/prod/files/Primus.pdf.

[n] Department of Energy. "Fact Sheet: Tehachapi Wind Energy Storage Project." May 2014. http://energy.gov/sites/prod/files/Tehachapi.pdf.

[o] Maui Electric Company. "Contract with Auwahi Wind Energy LLC." 2011.

[p] Hawaiian Electric Company. "Request for Proposal (RFP# 072114-01) for 60 to 200 MW of Energy Storage for Oahu." April 30, 2014. http://www.hawiianelectric.com/portal/site/heco/menuitem.508576f78baa14340b4c0610c510blca/?vgnextoid=03ebf219fe9a5410VgnVCM10000005041aacRCD&vgnextchannel=a595ec523c4ae010VgnVCM1000005c011bacRCRD&appInstanceName=default.

[q] California Public Utilities Commission. "Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems." Decision 13-10-040. October 17, 2013.

[r] Arizona Public Service Company and Residential Utility Consumer Office. "APS AND RUCO JOINT REQUEST FOR REVIEW." DOCKET NO. L-00000D-14-0292-00169, Case No. 169. 9 26, 2014.

[s] Consolidated Edison Company of New York. "Petition for Approval of Brooklyn Queens Demand Management Program." 14-E-0302. 2014.

Traditionally, power generation must meet consumer demand in real time. Storage provides a buffer between generation and volatility of customer demand. FERC Order 755, adopted in 2011, recognizes the ability of storage to contribute to frequency regulation on the grid faster than centralized generators. The box on page 3-11 provides more examples of Federal support for storage development and deployment.

The impact of storage can be location-dependent, so grid operators and regulators need new planning tools and procedures to make use of storage as a standard grid component and to optimize storage location and size. Changes in the way the United States values ancillary services can also help make the services provided by storage a competitive option. In the future, distributed storage (e.g., grid-connected electric vehicles) could be a transformative technology.

Changes to Power System Operations

Changes to power system operations and markets can provide significant existing flexibility, often at lower economic costs than building new transmission infrastructure. Operations examples include more frequent dispatch (which reduces the time frame over which a generator must follow a specified output level), smart network technologies, and increased plant cycling.

Smart network technologies and advanced network management practices minimize bottlenecks and optimize transmission usage. They provide unprecedented, real-time visibility across the energy system. Transmission and distribution planners and operators can use this information to employ the most reliable and cost-effective flexibility options. They can consider building new generation and transmission alongside other options like demand response or bigger balancing areas.

Forecasting and planning are low-cost ways of accessing system flexibility. System operators increasingly require variable renewable energy generators to forecast power output to improve the ability of system operators to commit, dispatch resources, deploy reserves, and improve situational awareness.[27] Integrating these data, along with wind and solar plant outage data, into market operations helps variable renewable energy plants participate in electricity markets.

Market Signals

Market signals can enable flexibility. Establishing short-term market products for flexible capacity (e.g., the California Independent System Operator (ISO) and Midcontinent ISO's proposed fast-ramping products) can also incentivize resources to respond to imbalances over the minutes-to-hours time frame. In market structures that more comprehensively value services provided to the grid, demand-side resources and storage could provide low-cost grid services, allowing more efficient grid operations and avoiding generation or transmission investments.[28] Cost savings to the power system attributable to demand response and energy storage can be much larger than the revenue they can receive in current market structures.[29]

Investments in Reliability and Resilience Can Have Multiple Benefits

North American Electric Reliability Corporation standards (subject to FERC review, approval, and independent enforcement authority) require the bulk electric system to withstand certain disruptive events, including most single contingencies and some multiple contingencies, with no interruption to transmission service or major customer outages. Some outages, or "non-consequential load losses," are tolerated in the case of extreme events, where multiple facilities are taken out of service simultaneously. The North American Electric Reliability Corporation requires bulk power system owners and operators to have plans in place to contain extreme events to prevent cascading outages to other regions.[30]

Resilience investments can require a substantial change in physical infrastructure, including building physical barriers or moving equipment, building backup systems, building non-wooden or reinforced poles, and burying lines underground.[31] Resilience investment also includes additional operations and maintenance activities, which primarily means more thorough tree trimming.[32]

Many energy sector investments to mitigate climate change can have co-benefits that make the grid more resilient to climate change impacts and extreme weather. Investments in energy efficiency, smart grid technologies, storage, and distributed generation can also contribute to enhanced resilience from environmental threats.[33] For example, DOE-funded demonstrations of distribution automation systems enabled a utility to restore power 17 hours faster following an outage, while other utilities have experienced marked improvements in outage interruption frequency and duration indices.[34] In addition to providing added redundancy, transmission can also provide the operational flexibility to adapt to long-term changes, such as an increase in the peak-to-average energy demand and water constraints on energy production.[35]

Drivers of Change for the Grid of the Future: New Technologies and Services

A second dimension of the emerging architecture for the grid of the future has to do with new or emerging technological innovations in grid operations. Many of the characteristics that customers desire in the grid of the future—affordability, reliability, sustainability, and an improved customer experience—will be facilitated by new technologies. The challenges to speeding the adoption of these technologies include developing network designs and open standards so they can communicate and operate seamlessly with other elements of the grid, as well as determining the value of the benefits that they bring to customers.

Innovative Technologies Have Significant Value for the System

An array of new technologies and data applications are enabling new electricity-related services, customer control choices, and investments that hold the promise of greatly improving electric consumer experience, as well as promoting a new ecosystem of innovation and revenues beyond the sale of electric kilowatt-hours.

Distributed generation systems provide consumers a number of benefits. According to a 2007 DOE study,[36] these benefits include increased electric system reliability; reduction of peak power requirements; provision of ancillary services, including reactive power; improvements in power quality; reductions in land-use effects and rights-of-way acquisition costs; and reduction in vulnerability to terrorism and improvements in infrastructure resilience.

A revolution in information and communication technology is changing the nature of the power system. The smart grid is designed to monitor, protect, and automatically optimize the operation of its interconnected elements, including central and distributed generation; transmission and distribution systems; commercial and industrial users; buildings; energy storage; electric vehicles; and thermostats, appliances, and consumer devices.[37] Smart grid technologies include a host of new and redesigned technologies, such as phasor measurement units or advanced metering infrastructure, that provide benefits such as increased reliability, flexibility, and resiliency.[38, 39, 40]

Within the delivery portion of the electric grid, smart grid technology is enabling sizable improvements in distribution and transmission automation. Many of these new technologies are "behind-the-meter," involving end-use management or generation on the consumers' premises; these end-use technologies are not directly germane to this installment of the QER. Nevertheless, as parts of an integrated electricity system, with growing effects on TS&D, behind-the-meter technologies do affect and interact with the systems that are the focus of this QER. For example, engineers will need to design and install components of the grid, such as safety interlocks, since two-way power flow, introduced by distributed generation, may pose a danger to line workers.

Emerging technologies on the distribution grid (whether digital communications, sensors, control systems, digital "smart" meters, distributed energy resources, greater customer engagement, etc.) present both technical and policy challenges and opportunities for the delivery of energy services. Power grids evolved organically in a bottom-up manner, as opposed to a centrally coordinated master plan. This build-up has led to large-scale legacy investments that require significant operating margins to maintain system stability, as opposed to more refined margins enabled by the rapid and precise control offered by new and emerging technologies.

These changes have injected uncertainties into a utility business model that typically has relied on continued load growth, steady economic returns, and long payback horizons.[41] While regulators, utilities, and the Federal Government are all engaged in addressing these uncertainties, developing appropriate rate structures for the benefits these technologies provide to the customer and the grid can be difficult, resulting in either over-investment or under-investment and higher costs to consumers.

Another key element in the development and use of information technologies on the grid relates to network coordination. The grid of the future would benefit from overall network architectures that allow for specific grid elements to be aligned in ways that allow them to contribute to solving problems that affect multiple grid components. Whole-grid coordination, in which these distributed elements are made to cooperate to solve a common problem (i.e., overall grid stability), is a key challenge and opportunity for new information and network technologies and approaches.

There are many other opportunities to infuse advanced technology into key operating elements of the grid. Some notable opportunities are shown in Table 3-1.

Table 3-1. Examples of Key Technologies for the Grid of the Future[42]

Grid Component/Opportunity	Description
AC/DC power flow controllers/converters	Technologies that adjust power flow at a more detailed and granular level than simple switching.
Advanced multi-mode optimizing controls	Controls capable of integrating multiple objectives and operating over longer time horizons, to replace simple manual and tuning controls, or controls that operate based only on conditions at single points in time.
Bilaterally fast storage	Energy storage in which charge and discharge rates are equally fast and thus more flexible.
Control frameworks	New hybrid centralized/distributed control elements and approaches.
Management of meta-data, including network models	New tools for obtaining, managing, and distributing grid meta-data, including electric network models.
Synchronized distribution sensing	Synchronization of measurements in order to provide more accurate snapshots of what is happening on the grid.
Transactive buildings	Buildings with controls and interfaces that connect and coordinate with grid operations in whole-grid coordination frameworks.
"X"-to-grid interface and integration	Interface technologies, tools, and standards for the general connection of energy devices to power grids; includes integrated mechanisms for coordinating those devices with grid operations in whole-grid coordination frameworks.
Distribution System Operation	Structure for clear responsibility for distributed reliability.

Innovation will introduce new grid components that are increasingly digitized, can provide new services for customers and grid operators, and continue to produce and reliably deliver affordable electricity to customers.

Communication with Customer Devices Will Improve Efficiency and Reliability of the Grid

The evolving role of the modern-day electricity customer is transforming into a more dynamic, transactive role in which customers are also becoming participants in electric system operations. Customers can create value to the electric system in two ways: as both suppliers of responsive demand and producers of distributed power. As suppliers of responsive demand, customers can provide capacity resources to the system that helps maintain reliability and affordable prices. As distributed producers of power, customers can provide power that could reduce total GHG emissions, increase resilience, and forestall infrastructure investments.

Three impediments to realizing customer value are related to communications. First, comprehensive communication and data standards need to be developed.[43] Competing, proprietary systems inhibit the adoption of technologies and control strategies and drive up the cost of deployment. Second, there is no uniform approach to characterizing the grid services that end-use devices can provide. Third, the communication and control interface devices between the customer as a distributed generator and the distribution system limit the types of service that the distributed generator can provide. In general, the lack of regulatory structures and standards are impeding the full utilization of information technology to enhance the efficiency and reliability of the grid.

Low-cost sensors and controls in buildings, distributed generation, electric vehicle charging, end-use storage, and other innovations make it increasingly important to integrate building devices and control systems with utility distribution systems to fully enable the development of new value propositions. Customer applications in residential and commercial buildings could potentially have economic benefits worth $59 billion (in 2009 dollars) by 2019, including packages of pricing, in-home displays, smart appliances, and information portals that would serve to reduce both energy demand and overall use.[44] Well-designed control systems also can increase building efficiency.[45]

Capturing these benefits requires building communication networks, allowing the components to interoperate and respond to a facility-wide control. One impediment to fully realizing the benefits of information technology is the balkanized structure of regulation. Early information technology adoption was accomplished by vertically integrated utilities that used computers as a tool to enhance their ability to perform existing functions. New information technology enables new behaviors, market mechanisms, and monitoring and operating procedures. While the reliability and efficiency of the system can be improved in the long run, these changes pose a threat to the status quo and have potentially significant unintended consequences and ambiguous benefits for utilities. As a consequence, there is a general caution associated with the wide-scale deployment of new information technology infrastructures and devices.

Speeding the adoption and accrual of potential benefits will require coordination of open standard development and clear business models that enable the benefits to be widely shared. An open standard for energy devices would be analogous to the voluntary industry USB standard developed in the mid-1990s, which allowed simple plug-and-play between smart phones, tablets, computers, chargers, printers, games, and many other peripheral devices. Its existence greatly expanded both the usability and types of all these personal electronic devices. Similar standards are emerging but not settled for the much newer set of information technology-enabled grid devices, leading to an ongoing lack of interoperability.

Implications of Electric Vehicle Penetration for the Grid

Battery-electric vehicles run on electricity and plug-in hybrid electric vehicles run on a combination of electricity and gasoline. In 2013, there were about 70,000 battery-electric vehicles and 104,000 plug-in hybrid electric vehicles—small numbers compared to the approximately 226 million registered vehicles in the United States. Total U.S. sales of plug-in electric vehicles (PEVs) have increased rapidly in recent years, but still represent only about 0.7 percent of new vehicle sales in 2014 (albeit up from 0.6 percent in 2013 and 0.4 percent in 2012). California is home to almost half of all of the Nation's PEVs, but only about 5 out of every 1,000 registered California vehicles are PEVs.[t]

There has also been a rapid recent increase in the numbers of charging stations. From 2011 to 2014, the numbers of public electric vehicle charging outlets grew from fewer than 4,000 to more than 25,000.[u] Various business models for developing new charging stations have emerged, as installation costs can be high.[v, w] For each infrastructure upgrade, utilities and regulators must assess costs (e.g., installation) and benefits (e.g., ancillary services).

According to the National Academy of Sciences in its 2013 report on electric vehicle deployment,[x] *"The existing electric infrastructure does not present a barrier to the expansion of PEV technology in the United States given the projected growth of PEV use in the next decade."* In addition, the report states that *"As PEVs account for a more significant share of total electricity consumption, the committee sees no barriers to provision of generation and distribution capacity to accommodate the growth through the normal processes of infrastructure expansion and upgrades in the electric utility industry."*

The National Academy of Sciences concludes that existing U.S. generation and transmission capacity could accommodate 5 million to 50 million PEVs. However, the report also suggests that if large numbers of PEVs were to be charged at the same time as residences also see peak loads, there could be potential for overloading elements of the local distribution system and thus a need for local upgrades. Furthermore, the National Academy of Sciences notes that concentrations of fast-charging stations, dense clustering of private PEV owner charging, or fleet-charging facilities could require grid upgrades. An assessment prepared for the Independent System Operator/Regional Transmission Organization Council noted that smart grid enhancements could allow electric vehicles to provide services to the grid, particularly related to demand response and load balancing.[y] Furthermore, smart grid developments could enable a shift in charging to off-peak periods and help avoid additional generation requirements.[z]

[t] Energy Information Administration. "California leads the nation in the adoption of electric vehicles." Today in Energy. December 10, 2014. http://www.eia.gov/todayinenergy/detail.cfm?id=19131.

[u] Department of Energy, Office of Energy Efficiency and Renewable Energy, Alternative Fuels Data Center. "Alternative Fueling Stations by Fuel Type." http://www.afdc.energy.gov/data/10332. Accessed January 16, 2015.

[v] Rocky Mountain Institute. "Pulling Back the Veil on EV Charging Station Costs." RMI Outlet. April 29, 2014. http://blog.rmi.org/blog_2014_04_29_pulling_back_the_veil_on_ev_charging_station_costs. Accessed January 16, 2015.

[w] Greene, D.L. "Alternative Transportation Refueling Infrastructure in the U.S. 2014: Status and Challenges." University of Tennessee Knoxville. March 31, 2015.

[x] National Research Council. "Overcoming Barriers to Electric-Vehicle Deployment: Interim Report." 2013. http://www.nap.edu/download.php?record_id=18320.

[y] KEMA and Taratec Corporation. "Assessment of Plug-in Electric Vehicle Integration with ISO/RTO Systems." Produced for the ISO/RTO Council. 2010. http://www.rmi.org/Content/Files/RTO%20Systems.pdf. Accessed January 27, 2015.

[z] Hadley, S.W. "Impact of Plug-in Hybrid Vehicles on the Electric Grid." Oak Ridge National Laboratory. 2006. http://web.ornl.gov/info/ornlreview/v40_2_07/2007_plug-in_paper.pdf.

In addition to interoperability, safe and improved connectivity is important to the deployment of new technologies to the grid. For example, there are voluntary industry standards for the interconnection of distributed generation of all types that connect customer-owned generation to the local distribution network. The majority of state public utility commissions use a voluntary standard issued in 2003 by the Institute of Electrical and Electronics Engineers (IEEE) known as the IEEE 1547 interconnection standards. These standards set technical guidelines for the interconnection of distributed resources less than 10 MW in size with the electric grid, including requirements relevant to the performance, operation, testing, safety considerations,

and maintenance of the interconnection. These standards are now in revision, with a goal of completion by 2018. Modifications are taking into account impacts on grid reliability; new technologies that offer two-way communications and intelligent controls; and dispatchability of some types of distributed generation plus extension to demand response, storage, and microgrids.

Updated standards will both improve grid safety and better use distributed energy resources in maintaining overall system reliability. In particular, as large fossil-fueled generators with spinning turbines retire, the system is losing the inertia that has helped maintain grid frequency and thus grid reliability. Properly configured with appropriate communications, inverters used with distributed generation or storage can provide frequency regulation services to the grid to fill this gap. Conversely, improper connections or protocols could lead to simultaneous disconnection of all distributed energy resources under particular circumstances. While there is an existing process underway to update the IEEE 1547 interconnection standards, finding ways to accelerate the update of these standards will provide increased benefits to both customers and the reliability of the system.

Appropriate Valuation of New Services, Technologies, and Energy Efficiency

Ultimately, the electric system exists to serve load—or the demand for electric services—from the residential, commercial, industrial, and transportation sectors. There is a suite of services that the grid provides to meet real-time changes in load and supply, among other things. A better understanding of the full costs and benefits of those services would allow regulators, utilities, and customers to develop more fair and equitable pricing structures.

These services and a range of other important societal goals are enabled by new technologies. Distributed energy and smart grid technologies offer the potential to help meet America's changing energy needs, minimize the environmental impact of electricity generation, strengthen economic growth, and improve the reliability of the Nation's electrical infrastructure. As noted, the full spectrum of existing and emerging technologies includes new intelligent grid (smart grid) delivery technologies, energy efficiency, combined heat and power, fuel cells, gas turbines, rooftop PV, distributed wind, plug-in hybrid and all-electric vehicles, distributed storage, demand response, and transactive building controls.

At high penetrations, many of these new technologies could challenge current distribution systems and the functional integrity of the current electricity system. New investments and changes to existing regulatory, policy, financial, and business structures may be necessary to fully realize the benefits of these technologies. Regulators and policymakers will need to address the operational issues associated with new technologies, as well as longer-term concerns, such as how the loss of revenue (and a utility's ability to cover fixed costs) and load resulting from increasing numbers of some installations of distributed energy resources could challenge utilities' financial health under current business models.

A key element for addressing the operational and business model concerns posed by new technologies centers on valuation (i.e., "What are the benefits of new services and technologies to the grid?" and conversely, "What is the cost of the services the grid provides to customers?"). There is no agreement on the answers, though, as answers depend on the situation. This issue has been examined in numerous valuation studies in the public domain. These studies do not consider the same set of impacts from one study to the next. For example, not all studies explicitly consider impacts on transmission and distribution, such as capacity avoidance, grid support services, or external impacts like avoided GHGs. The monetized estimates that different studies assign to a given service or impact (capacity, energy, system losses) can range by a factor of as much as five or more.

There currently are no transparent, broadly accepted methods that can be used by stakeholders to determine the costs and benefits associated with integrating new services and technologies into the grid.[46] Clearer valuation methods would empower legislators and regulators in their efforts to address their local needs as

they formulate strategies and plans to provide a portfolio of electricity options that meet their state-specific goals for reliable, affordable, and clean electricity. It is also important for policymakers to understand that, as they work to value services on both sides of the meter, there is the potential for stranded assets (i.e., assets for which investments have been made but cannot be recovered) on both sides; valuation policies must take these issues into consideration as well.

Net Metering

The challenges associated with integrating new technologies into the current electricity grid system are illustrated by the variety of opinions on net metering. Net metering is a system for paying for generation located on customer facilities—typically, although not exclusively, small residential solar generators. Currently, 45 states have Net Energy Metering programs that credit customers in some way for the energy they produce onsite.[47] The most common type of Net Energy Metering customer today owns or leases a rooftop PV system, but current regulations often apply to other distributed energy technologies, such as gas-fired turbines and combined heat and power. With rapid solar PV market penetration, controversies among utilities, consumer groups, solar businesses, and other stakeholders have arisen in several states over how to account for the full cost of grid services, placing pressure on legislators and regulators to understand conflicting positions and analyses supporting them.

Valuing Ancillary Services

Ancillary services are defined by the North American Electric Reliability Corporation as "those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with good utility practice."[48] Types of ancillary services include ramping, voltage support, and frequency support, all of which are furnished by a combination of generation and transmission facilities. Ultimately, the system operator is responsible for ensuring that there are adequate ancillary services at all times to maintain reliability. The ability to provide ancillary services, such as frequency support, is changing with the transformation of the electric generation system. As the electric system continues to evolve, system planners and grid operators will need to value and integrate the services that new technologies can provide to maintain system stability and reliability. New payments, or changes to existing payment methods (both to generation owners and to other potential ancillary service providers), may be necessary to ensure continued provision of needed ancillary services to maintain grid reliability.

Consistent Measurement and Evaluation of Energy Efficiency

The evaluation, measurement, and verification of energy efficiency savings are critical as efficiency becomes increasingly important as a mechanism to meet a variety of goals, including reducing the need to build additional generation and GHG reduction. Many entities have made progress toward standardizing the evaluation of energy efficiency. These methods can help regulators understand the opportunities energy efficiency creates for infrastructure avoidance.

Ratepayer-funded efficiency programs run by utilities and third parties, energy service companies' projects, codes and standards, and other efficiency programs have achieved significant energy savings over the last three decades.[49] These programs have developed in different ways across the country, along with some state variation in protocols and procedures for measuring and verifying savings. While inconsistencies can complicate efforts to compare measured savings across jurisdictions, a number of important standardization efforts have emerged in recent years at the state and regional levels that have started to address these issues. These include efforts led by the Northwest Regional Technical Forum and the Northeast Energy Efficiency Partnership that include development of regional databases of energy savings. Building on this momentum, DOE's voluntary Uniform Methods Project for Determining Energy Efficiency Program Savings has convened policy stakeholders and

technical experts to develop a set of protocols for determining savings from energy efficiency measures and programs. Over the last 2 years, the Uniform Methods Project has issued more than 20 protocols for common residential, commercial, and crosscutting energy efficiency measures. The Energy Information Administration has also tracked energy efficiency program evaluations.

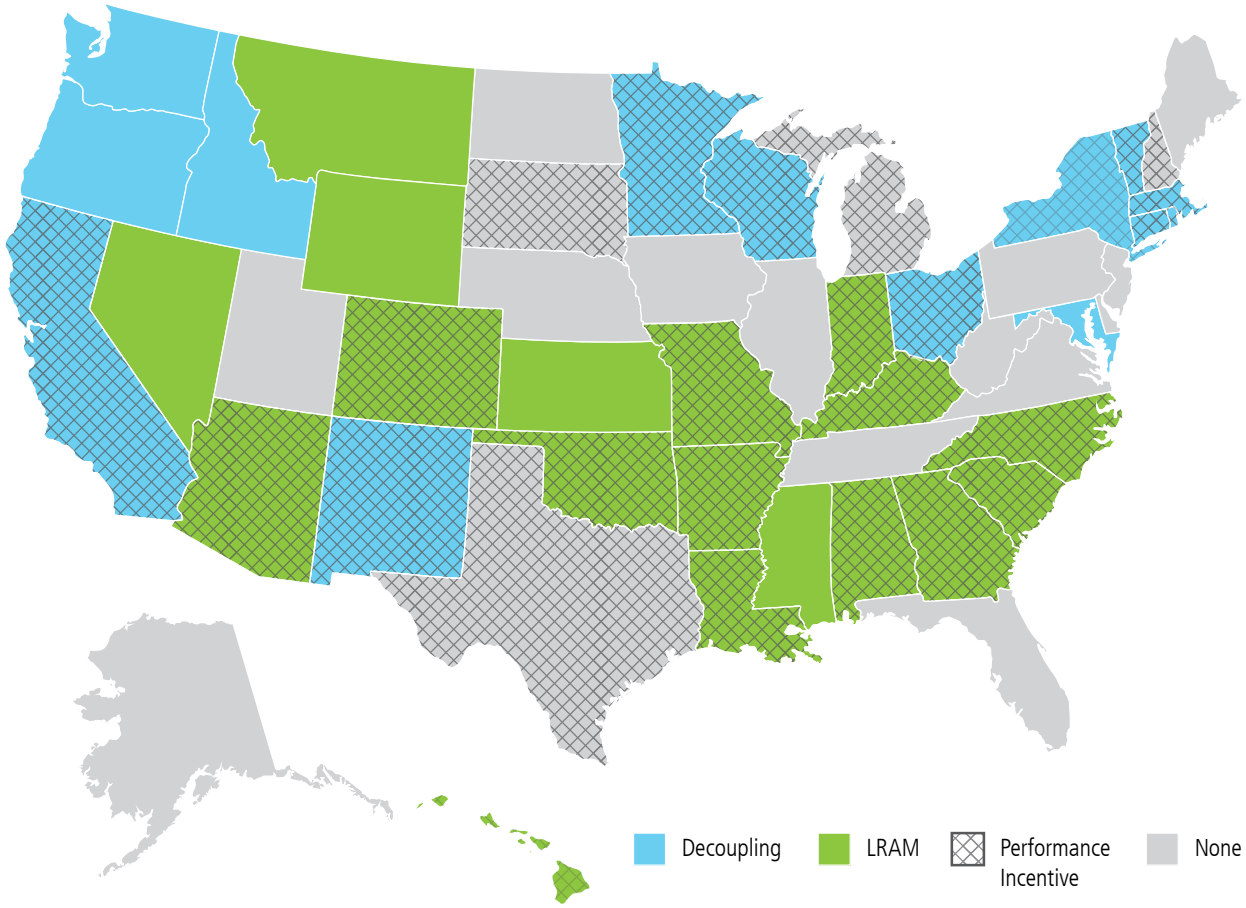
Drivers of Change for the Grid of the Future: Institutions and Utility Business Models

A third dimension of the architecture for the grid of the future encompasses all the actors involved in managing the grid, including in industry and regulatory bodies (at all levels of government). These businesses and institutions shape the operation, management, and regulation of the grid. Incorporation of the new technologies and services will require an evolution in these businesses and institutions.

States Are the Test Beds for the Evolution of the Grid of the Future

States have the primary role in regulating the retail provision of electricity (see Figure 3-5), as well as the siting of transmission and generation. Due to this primacy, states are at the forefront of managing the transition to the grid of the future. Historically, states have been the laboratories for developing policies that reflect their individual and regional situations, and in the electricity sector, state policies reflect differences in resource mix, priorities, geography, economies, and even culture.

Figure 3-5. Different State Approaches to Energy Efficiency[50]



Thirty-six states have adopted regulatory approaches to promote utility investment in energy efficiency: decoupling, lost-revenue adjust mechanisms ("LRAM"), or performance incentives.

As the complexity of the grid increases, states are working to develop policies that incorporate new services and technologies in a manner that maintains affordability and reliability. The unique circumstances of each state have resulted in a diverse set of responses across a range of issues confronting the electricity sector. For example, many states have adopted policies to support utility investments in energy efficiency. There are at least three different regulatory approaches being used: decoupling, lost revenue adjustment mechanism, and a broad set of methods to allow performance incentives (see Figure 3-5). These efforts create a regulatory model that rewards utility shareholders for effective energy efficiency efforts that lower ratepayer bills in the long term. Another example of state innovation is the cost-allocation scheme member states in the Midcontinent ISO and Southwest Power Pool negotiated among themselves for the funding of large region-wide transmission upgrades for each of their regions, which was then approved by FERC.[51, 52]

Different Industry Structures and Business Models Rule Out "One-Size-Fits-All" Solutions to Challenges

The grid is financed, planned, and operated by numerous entities that cross states, regions, and countries. It provides valuable services and includes a variety of industry types and a range of business models that often reflect regional differences in resource mix.

Policies designed to provide consumers with affordable and reliable electricity in the future must take into account the variety of business models for investing, owning, and operating grid infrastructure. The nature of the entities that comprise the grid has changed and will continue to do so. The earliest model of electric service delivery was the investor-owned, vertically integrated utility, namely the Edison Illuminating Company that used the New York City Pearl Street Station generator in 1882 to begin serving customers. Following, in the late 1880s and 1890s, was the establishment of public power utilities, which were also vertically integrated, in small towns to also serve local loads with generation. Now, as shown in Table 3-2, the basic functions of the vertically integrated utility are performed by a wide variety of entities with different ownership structures, pursuing different functions.

The variety of ownership and scope of the entities that comprise the grid leads to a complex set of motivations and decision drivers. The reliable operation of the grid is a testament to the integration of these different interests. There are five different predominant ownership types: (1) investor owned; (2) cooperatively owned, owned by their member customers; (3) publicly owned, such as by municipalities, states, public utility districts, and irrigation districts; (4) Federally owned; and (5) merchant companies that are competitive entities in generation, transmission, or retail supply.

Table 3-2. Taxonomy of Utility Business Models (examples, ownership, and scope)[53]

	State-Regulated IOUs	Cooperatively Owned	Publicly Owned	Federally Owned	Merchant
Vertically Integrated (T,D,G)*	Oklahoma Gas & Electric	None	Los Angeles Dept. of Water & Power	None	None
Transmission and Distribution	Pepco	Southern Maryland Electric COOP (SMECO)	Clallam County Public Utility District	None	None
Generation and Transmission	None	Basin Electric G&T	New York Power Authority	Tennessee Valley Authority	LS Power
Generation and Distribution	DTE Energy; Consumers Energy	Fox Island (ME) Electric	Lansing (MI) Board of Water & Light	None	NRG
Transmission	None	Upper Missouri Power Cooperative	Transmission Agency of Northern Calif.	Western Area Power Adminstration, Bonneville Power Administration, Southwestern Power Administration	ITC; Hudson Transmission; Transource Energy; Clean Lines Energy Partners
Distribution	Mt. Carmel Public Utility Co.	Kenergy	Nashville Electric Service	None	None
Generation	None	Oglethorpe Power Corporation	Wyoming Municipal Power Agency	Bureau of Reclamation	Calpine; BP Energy; Tenaska;

* (T,D,G= Transmission, Distribution, and Generation)

There is a diversity of ownership structures in the U.S. electricity sector. Such diversity often precludes one-size-fits-all policies.

Although all utilities may invest in demand response and energy efficiency, each ownership pattern engenders different interests in performance of service, investment, and market structure. For example, cooperatives have been innovative in their use of direct load control to modify peak load conditions,[54] while publicly owned utilities have been leaders in energy efficiency.[55] Because investor-owned utilities earn a return on capital expenses, and without special incentives, do not earn a return on cost-saving operational expenses, this class of utilities tends to lead in the development of new service through capital-intensive assets.

Investor-owned companies have fiduciary obligations to increase shareholder value. Regulated entities that earn profit based upon a return on invested capital lack a strong incentive (absent explicit requirements and incentives) to invest in energy efficiency practices. In contrast, public power and cooperative utilities are motivated to keep customers' bills down and, as such, can optimize the provision of service by using both capital-intensive options and less capital-intensive alternatives (e.g., energy efficiency).

Merchant generators whose profits are the residual revenues after expenses are paid (including return on capital) are motivated to maximize revenue. The Federal Power Marketing Administrations, such as the Western Area Power Administration and the Bonneville Power Administration, must follow the dictates of their statutory authorities. The balancing authorities, some of which are Regional Transmission Organizations or ISOs, in turn, are concerned about maintaining reliability while operating the bulk power system.

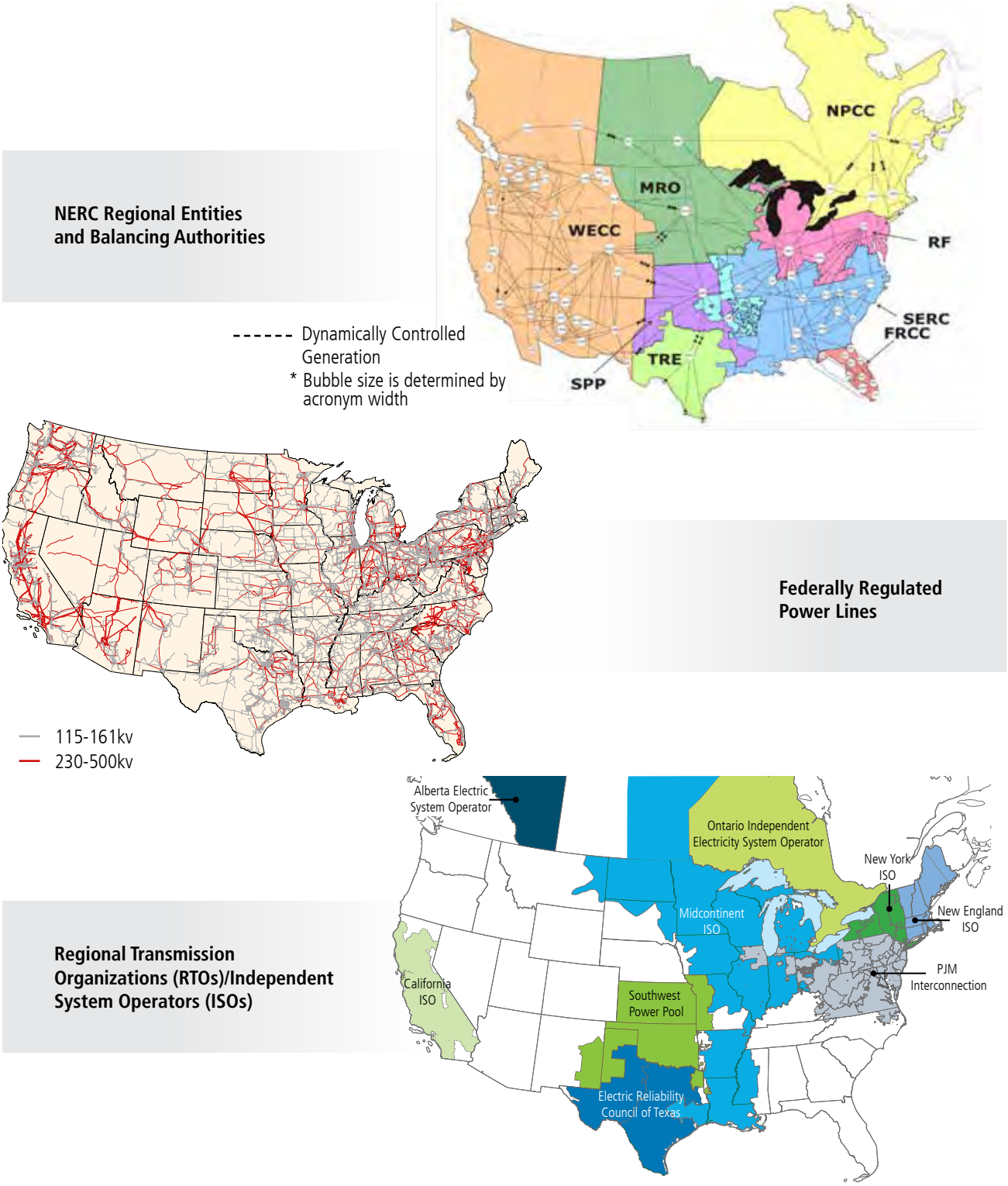
Fragmented and Overlapping Jurisdictions Threaten to Impede Development of the Grid of the Future

Federal, regional, and state institutions and regulatory structures that have evolved over decades to manage the electric grid are increasingly interacting and overlapping. The geographical boundaries of the institutions are not coincident with the flow of electrons on the physical system. The increasing physical complexity of the grid will only complicate governance and analysis. Policymaking to address regulatory and operational challenges of the evolving grid is more difficult because models used to analyze the physical flows of electricity do not align with the institutional and regulatory structures (see Figure 3-6).

The current Federal-state regulatory boundary dates back to the 1930s, when the Federal Power Act substantially expanded the responsibilities of the Federal Power Commission (the predecessor to FERC) and created Federal oversight of wholesale sales of electricity and of transmission of electricity in interstate commerce, as well as state oversight of retail sales and distribution of electricity. In recent decades, organized wholesale markets have spread geographically and incorporated a greater variety of products with a broader set of market participants. This trend—coupled with the increased ability of end-use consumers to supply distributed generation, demand response, and other services—has and will continue to raise questions about the dividing line between state and Federal jurisdiction.[56]

This threatens to impede the development of markets that efficiently integrate both utility-scale and small-scale participants. While FERC and the National Association of Regulatory Utility Commissioners have engaged in a collaborative dialogue on a range of topics (smart grid, demand response, enforcement, and others) since 2006,[57] Federal and state regulators should seek new ways to coordinate goals across their respective jurisdictions, without which the Nation will not be able to take full advantage of the efficiencies offered by emerging technologies and the grid of the future.[58]

Figure 3-6. Select Electricity Jurisdictions[59]



Transmission lines, which are regulated at the Federal level, cross state boundaries and connect the regional organizations that manage and operate the bulk power electricity grid. In contrast, states regulate the distribution of electricity to end-use customers for entities under their jurisdiction, as well as the siting of transmission on non-Federal lands. Further, in most states, local appointed or elected governing boards handle the regulation of distribution for their publicly or cooperatively owned electric utility. This diversity of institutions and differences in jurisdictional boundaries create challenges in grid governance (given that changing the grid in one location can alter electricity dynamics over a large area).

Policy Framework for the Grid of the Future

The transition from today's existing grid to the grid of the future will be challenging. The electric grid is highly complex, has significant regional variability, and should be managed to accommodate a range of possible futures. The vision of the future electric grid described earlier in this chapter was developed after a year-long QER process of analyses and stakeholder engagement. The recommendations that follow are guided by five key policy principles that emerged from this work.

- The future grid should encourage and enable energy efficiency and demand response to cost effectively displace new and existing electric supply infrastructure, whether centralized or distributed. The policies, financial tools, and pricing signals that enable customers to save money and energy while enhancing economic growth should be preserved and strengthened as business models evolve.
- The future grid should provide balanced support for both decentralized power sources and the central grid. As the costs of decentralized power sources and storage continue to fall, there will be increased opportunities for end users to partially or completely supply their own electricity. At the same time, the vast majority of American homes and businesses will continue to rely on the power grid for some or all of their electricity. It is essential, then, that investment in both centralized and decentralized systems occur in a balanced manner, preserving high-quality service for all Americans while simultaneously enabling new options and services that may reduce energy costs or climate impacts. Similarly, access to renewable energy, energy efficiency improvements, and new energy-related services should not be limited to isolated customer groups, but rather become an integral part of the universal service that both decentralized and centralized grid customers enjoy.
- In the future grid, new business and regulatory models must respect the great regional diversity in power systems across the United States, as well as the critical roles played by state, local, tribal, and regional authorities, including state public service commissions and regional grid operators. The drivers of change in the power system cut across the traditional boundaries of state and Federal regulation and thereby introduce new challenges in designing and overseeing new business and regulatory models. An unprecedented amount of consultation and collaboration will be necessary to ensure that national objectives are met alongside complementary state policies in power systems that are inherently regional in their scope and technology.
- Planning for the future grid must recognize the importance of the transmission and distribution systems in linking central station generation—which will remain an essential part of the U.S. energy supply for many years to come—to electricity consumers. Transmission and generation both benefit from joint, coordinated planning. Transmission can allow distant generation—where there may be excess capacity—to supplement local supply and avoid the need to build new plants. New generation sometimes requires new transmission, especially remotely sited renewables or new nuclear plants. Utility and Regional Transmission Organization planning processes and tools should continue to evolve to evaluate transmission, generation (both central and distributed), and demand-side resources holistically.
- Finally, the careful combination of markets, pricing, and regulation will undoubtedly be necessary in all business and regulatory models of the future grid. While the precise nature and scope of the market structures in the future grid may vary considerably, there is little doubt that markets in one form or another will be an important means of providing access to new technologies and services. Even in settings where prices are regulated, novel approaches can allow beneficial new pricing and service structures. Moreover, both new and traditional financing options provided by capital markets will be an important element in the future industry landscape.

QER Recommendations

The Administration and Congress should support or incentivize investment in electricity infrastructure reliability, resilience, and affordability through the development of tools, methods, and new funding for planning and operating the grid of the future. Accordingly, we recommend the following:

Provide grid modernization research and development, analysis, and institutional support: A modernized 21st century grid will require a governing framework that values and optimizes the benefits from new technologies and services, as well as a physical infrastructure that maintains reliability, resilience to disruption, cost effectiveness, and flexibility to adapt to these changes. Early and strategic investments by DOE in foundational technology development, enhanced security capabilities, and institutional support and stakeholder engagement provide decision makers with a common set of tools that balances electric industry and consumer interests. Though small relative to the size of the industry, DOE's investment is significant compared to utilities' limited spending on innovation, which stems from an investor-owned business model where profits are based on return on capital expenditures, as well as public- and consumer-owned power's requirement for lowest feasible rates. The President's Fiscal Year 2016 Budget requests $356 million for DOE's Grid Modernization Initiative.

To reflect the rapidly shifting grid landscape, DOE should continue to pursue a multi-year, collaborative, and cost-shared research and development, analysis, and technical assistance program:

- Technology innovation resulting from research and development coordinated among DOE offices, creating new tools and technologies in areas such as the following:
  - Design and planning tools to model emerging needs
  - System control and power flow to optimize for new grid capabilities
  - Grid sensing and measurements for determining changes in variable generation markets and infrastructure conditions
  - Devices and integrated systems testing for evaluation and validation of new technologies in a systems context
  - Grid security and resilience efforts to protect, prevent, analyze, and respond to threats by developing physical and cybersecurity technology and standards
  - Risk management, including integrated demonstration of promising new technologies with new institutional approaches.
- Institutional support and alignment, including analyses, workshops, and dialogues to highlight key policy and market challenges and options for grid transformation.

The cost of this program is estimated to be $3.5 billion over 10 years.

Establish a framework and strategy for storage and flexibility: Energy storage is a key functionality that can provide flexibility, but there is little information on benefits and costs of storage deployment at the state and regional levels, and there is no broadly accepted framework for evaluation of benefits below the bulk system level. DOE should conduct regional and state analyses of storage deployment to produce a strategy for flexibility and storage. The strategy will integrate the findings from these analyses and make them easy for all types of stakeholders, including regional and state leaders, to understand and implement where appropriate. It will also establish a common framework for exploring means, methods, and technologies that can enhance grid flexibility, regionally, in states, and load-serving entities.

QER Recommendations (continued)

The national energy system storage strategy will address a suite of approaches that enable flexibility, including integrated planning methods, system operations and markets, demand and storage, conventional and variable renewable generation, and interconnected transmission networks.

Conduct a national review of transmission plans and assess barriers to their implementation: Transmission is critical both to ensuring reliability, as well as to connecting generation to load. While DOE has funded interconnection-level analyses of transmission needs and specific studies of transmission needs for renewable generation, a more detailed and comprehensive national review of transmission plans is warranted. DOE should carry out such a review to include assessments on the types of transmission projects proposed and implemented, current and future costs, consideration of interregional coordination, and other factors. Synthesizing this information at a national level would better inform and guide the development of transmission, including opportunities for additional regional or interregional coordination. In conjunction with such a review, it will be critical to assess incentives and impediments to the development of new transmission. Such an assessment should include a review of existing Federal incentives, implementation of Section 1222 of the Energy Policy Act of 2005 to enable third-party transmission projects partnered with the DOE Western and Southwestern Power Administrations, implementation of the $3.25 billion Western Area Power Administration Transmission Infrastructure Program, siting constraints, and other incentives and impediments that may exist at both the national and local levels.

Provide state financial assistance to promote and integrate TS&D infrastructure investment plans for electricity reliability, affordability, efficiency, lower carbon generation, and environmental protection with a focus on regional coordination: States are the test beds for the evolution of the electric power system. DOE should provide competitive funding for states to promote and integrate TS&D infrastructure investment plans for electricity reliability, affordability, efficiency, lower carbon generation, and environmental protection (including climate mitigation).

- As described in this chapter, states can play an important role in promoting grid reliability as new technologies, including distributed generation, are added to the grid, and consumers demand more services from the electric power system. The increasing interdependency of natural gas and electricity systems creates additional planning requirements, as does climate change and extreme weather events.
- States have historically established separate agencies for reliability and environmental regulation of the electric power sector that operate independently of each other. The actions required to meet the goals of an affordable, resilient, reliable, and cleaner electricity sector are, however, becoming increasingly interdependent. States can provide innovative ways to address new trends that allow the electric sector to reliably provide services that meet environmental, resilience, and efficiency goals. In making awards under this program, DOE should require cooperation within the planning process of energy offices, public utility commissions, and environmental regulators within each state; with their counterparts in other states; and with infrastructure owners and operators and other entities responsible for maintaining the reliability of the bulk power system.

The estimated support for this program is about $300 million to $350 million over 5 years.

QER Recommendations (continued)

Coordinate goals across jurisdictions: Technology is indifferent to state-Federal boundaries and jurisdictions; technology users cannot be. Both Federal and state governments need to play constructive and collaborative roles in the future to ensure that consumers and industry are able to maximize the value of new technologies to enhance resilience and reliability and mitigate climate change. While the notions of retail versus wholesale have, in some respects, become blurred, the states still have a strong and important role in electricity regulation. The variety and strength of state policies on energy efficiency, storage, renewable energy, smart grid, and even GHG regulation demonstrates the undiminished importance of the power sector to state leaders, notwithstanding technological change. At the same time, portions of the electric power sector have an important role to play in improving the efficiency of the wholesale markets overseen by FERC at the Federal level. DOE should play a convening role to bring together public utility commissioners, legislators, and other stakeholders at the Federal, state, and tribal levels to explore approaches to integrate markets, while respecting jurisdictional lines, but allowing for the coordination of goals across those lines.

Value new services and technologies: Efficient characterization and valuation of services provided to the grid by existing and new technologies is important for maintaining reliability and affordability of the rapidly evolving electricity system and providing clear price signals to consumers. Existing methods for establishing values and rates should appropriately compensate new technologies, with the potential to more effectively provide grid services reliably, affordably, and in compliance with environmental regulations. The Federal Government can play a role in developing frameworks to value grid services and approaches to incorporate value into grid operations and planning.

- DOE should convene stakeholders to define the characteristics of a reliable, affordable, and environmentally sustainable electricity system and create approaches for developing pricing mechanisms for those characteristics.
- The ability of distinct grid components to provide grid services should be evaluated, and options for increasing the viability of components to provide grid services should be reviewed—this would allow market operators and regulators to have a more complete understanding of the range of technologies and strategies that can provide grid services.
- DOE should also work with stakeholders to develop a framework(s) for identifying attributes of services provided to the grid by electricity system components, as well as approaches to incorporate the valuation of grid service attributes in different regulatory contexts (e.g., pricing or incorporation in planning processes).
- The convening efforts recommended here will build on past DOE workshops on the value of storage and distributed energy resources (discussed in Chapter X, Analytical and Stakeholder Process). The frameworks developed through this process could be used by FERC, state public utility commissions in ratemaking proceedings, Regional Transmission Organizations in their market rule development, or utilities in the operation and planning of their systems.

QER Recommendations (continued)

Improve grid communication through standards and interoperability: A plethora of both consumer-level and grid-level devices are either in the market, under development, or at the conceptual stage. When tied together through the information technology that is increasingly being deployed on electric utilities' distribution grids, they can be an important enabling part of the emerging grid of the future. However, what is missing is the ability for all of these devices to coordinate and communicate their operations with the grid, and among themselves, in a common language—an open standard. One analogy is the voluntary industry USB standard developed in the mid-1990s that allows simple plug-and-play between smart phones, tablets, computers, chargers, printers, games, and many other peripheral devices, and whose existence has greatly expanded both the usability and types of all these personal electronic devices. Similar standards are emerging but not settled for the much newer set of information technology-enabled grid devices (i.e., a lack of interoperability exists). The Department of Commerce's National Institute of Standards and Technology (NIST) was very active in working with industry and other interested parties to develop several generations of voluntary standards to bring interoperability to grid-connected devices. NIST's efforts have now transitioned to the industry-based Smart Grid Interoperability Panel. DOE is supporting efforts by IEEE to develop next-generation standards for inverters used by distributed generation. While the Federal Government lacks authority to mandate standards in these areas, it can take additional steps. In conjunction with NIST and other Federal agencies, DOE should work with industry, IEEE, state officials, and other interested parties to identify additional efforts the Federal Government can take to better promote open standards that enhance connectivity and interoperability on the electric grid.

Establish uniform methods for monitoring and verifying energy efficiency: The measurement and verification of energy efficiency savings will be increasingly important as efficiency continues to become not just a source of revenue, but a mechanism by which the utility can meet its GHG reduction goals. Regulators need ways to understand, validate, and value savings from energy efficiency practices, including understanding the value of infrastructure avoidance as a result of efficiency investments. Through its Uniform Methods Project, DOE should accelerate the development of uniform methods for measuring energy savings and promote adoption of these methods in public and private efficiency programs.

RECOMMENDATIONS IN BRIEF:
Modernizing the Electric Grid

Provide grid modernization research and development, analysis, and institutional support. The Department of Energy (DOE) should continue to pursue a multi-year, collaborative, and cost-shared research and development, analysis, and technical assistance program for technology innovation that supports grid operations, security, and management, as well as for analyses, workshops, and dialogues to highlight key opportunities and challenges for new technology to transform the grid.

Establish a framework and strategy for storage and grid flexibility. DOE should conduct regional and state analyses of storage deployment to produce a common framework for the evaluation of benefits of storage and grid flexibility, and a strategy for enabling grid flexibility and storage that can be understood and implemented by a wide range of stakeholders.

Conduct a national review of transmission plans and assess barriers to their implementation. DOE should carry out a detailed and comprehensive national review of transmission plans, including assessments on the types of transmission projects proposed and implemented, current and future costs, consideration of interregional coordination, and other factors. A critical part of this review should be to assess incentives and impediments to the development of new transmission.

Provide state financial assistance to promote and integrate transmission, storage, and distribution infrastructure investment plans for electricity reliability, affordability, efficiency, lower carbon generation, and environmental protection. In making awards under this program, DOE should require cooperation within the planning process of energy offices, public utility commissions, and environmental regulators within each state; with their counterparts in other states; and with infrastructure owners and operators and other entities responsible for maintaining the reliability of the bulk power system.

Coordinate goals across jurisdictions. DOE should play a convening role to bring together public utility commissioners, legislators, and other stakeholders at the Federal, state, and tribal levels to explore approaches to integrate markets, while respecting jurisdictional lines, but allowing for the coordination of goals across those lines.

Value new services and technologies. DOE should play a role in developing frameworks to value grid services and approaches to incorporate value into grid operations and planning. It should convene stakeholders to define the characteristics of a reliable, affordable, and environmentally sustainable electricity system and create approaches for developing pricing mechanisms for those characteristics. The goal should be to develop frameworks that could be used by the Federal Energy Regulatory Commission, state public utility commissions in ratemaking proceedings, Regional Transmission Organizations in their market rule development, or utilities in the operation and planning of their systems.

Improve grid communication through standards and interoperability. In conjunction with the National Institute of Standards and Technology and other Federal agencies, DOE should work with industry, the Institute of Electrical and Electronics Engineers, state officials, and other interested parties to identify additional efforts the Federal Government can take to better promote open standards that enhance connectivity and interoperability on the electric grid.

Establish uniform methods for monitoring and verifying energy efficiency. Through its Uniform Methods Project, DOE should accelerate the development of uniform methods for measuring energy savings and promote widespread adoption of these methods in public and private efficiency programs.

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Attachment C

SERC Reliability Corporation Information Summary

July 2014

SERC Reliability Corporation

Information Summary

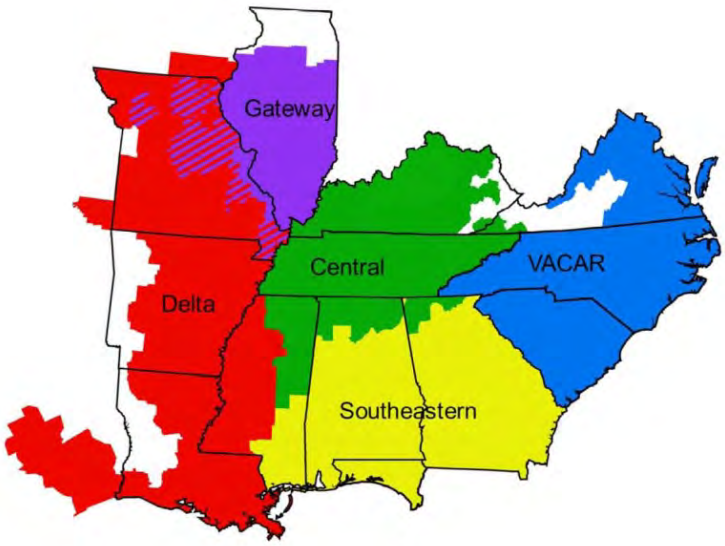
July 2014

The intent of this pamphlet is to concisely summarize data that is useful to SERC (SERC Reliability Corporation) members and those interested in the organization. This pamphlet presents historical and projected seasonal peak-hour demand, annual net energy for load, capacity resource and other information for the SERC Region and each of its five subregions. SERC's annual reliability report provides detailed information beyond that which can be readily summarized here. A list of SERC members and other commonly used reference items are included to enhance the usefulness of this publication.

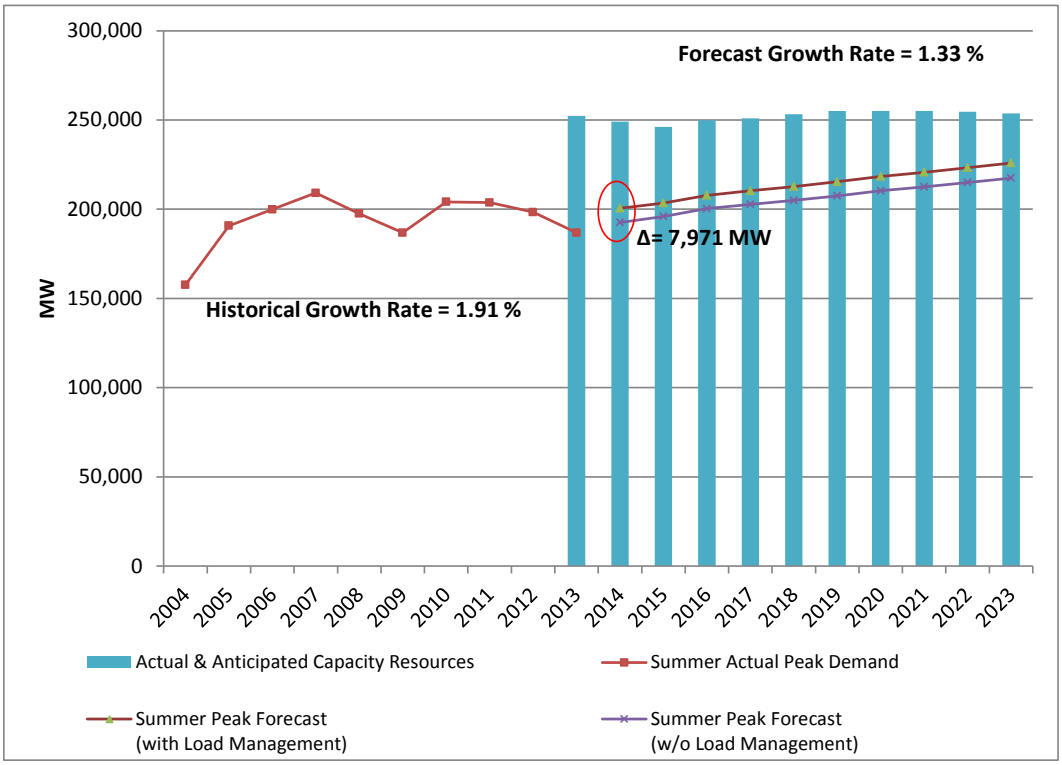
SERC is a nonprofit corporation responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states. Owners, operators, and users of the bulk power system in the SERC Region serve electric customers in an area of approximately 560,000 square miles. SERC membership includes 54 member entities consisting of publicly owned (federal, municipal, and cooperative) and investor-owned operations. In the SERC Region, there are 23 balancing authorities and over 200 registered entities under the NERC (North American Electric Reliability Corporation) functional model.

On July 20, 2006, NERC was certified as the ERO (Electric Reliability Organization) in the United States, pursuant to Section 215 of the Federal Power Act. On June 18, 2007 the initial reliability standards developed by NERC (and approved by FERC) became mandatory, with legal authority for enforcement granted to the ERO. Included in the ERO certification is a provision for the ERO to delegate authority for the purpose of proposing and enforcing its reliability standards to regional entities by entering into delegation agreements with regional entities such as SERC.

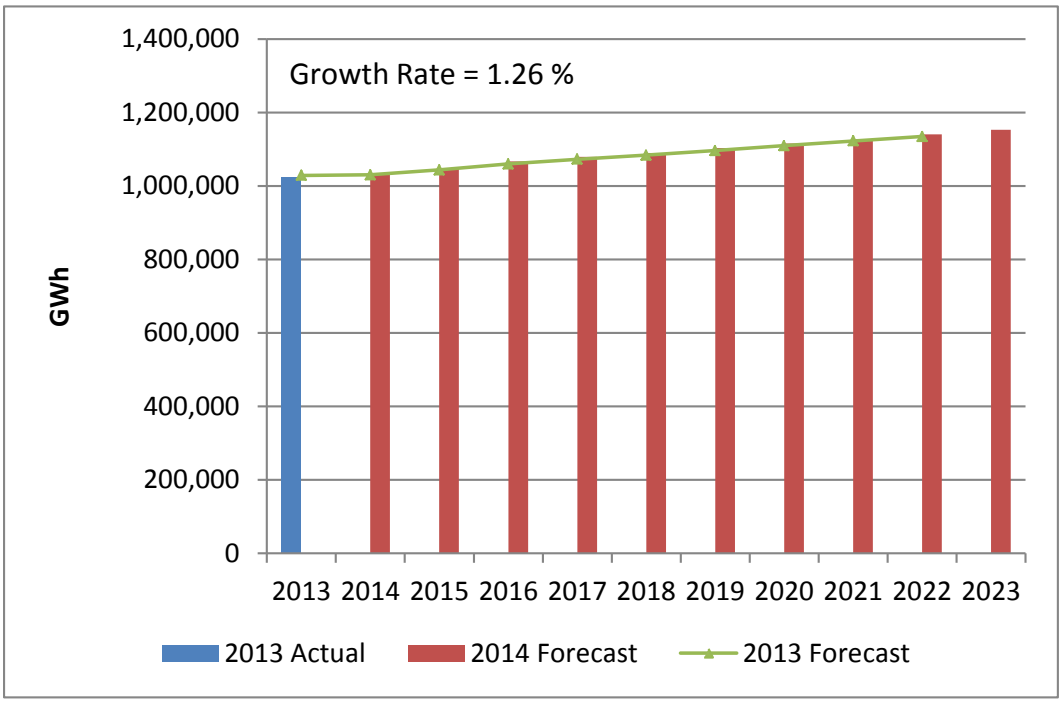
SERC is divided geographically into five subregions that are identified as Central, Delta, Gateway, Southeastern, and VACAR. Additional information can be found on the SERC website (www.serc1.org).



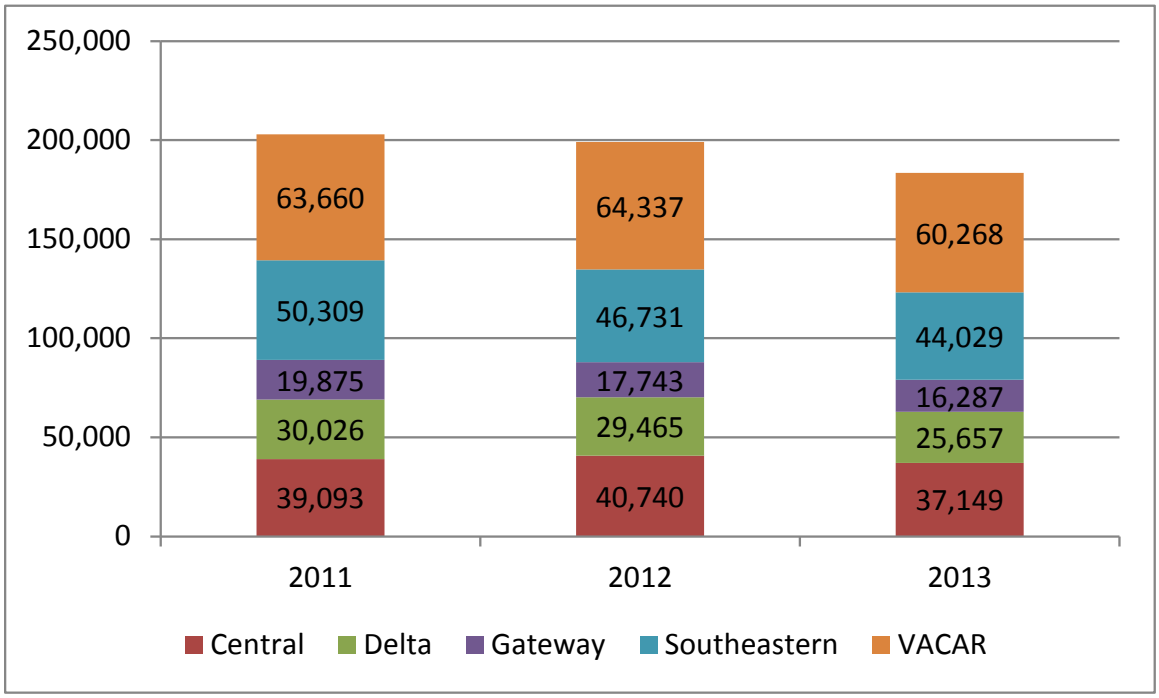
Actual Peak Demand / Projected Peak Demand and Resources



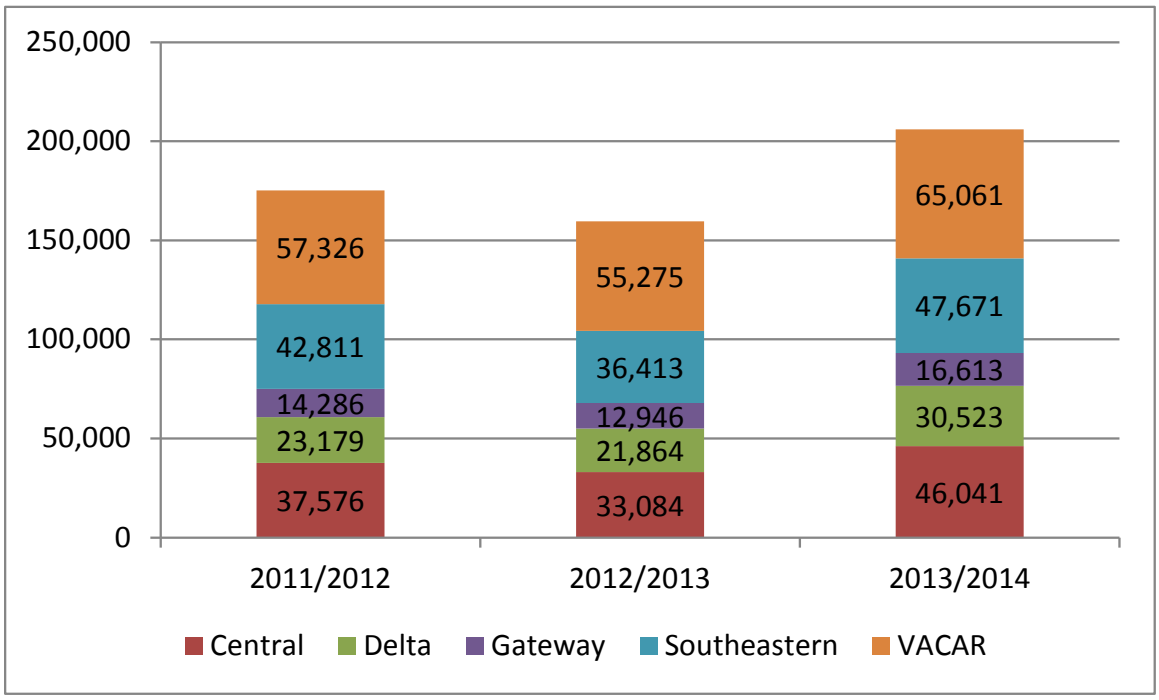
Actual / Projected Net Energy For Load



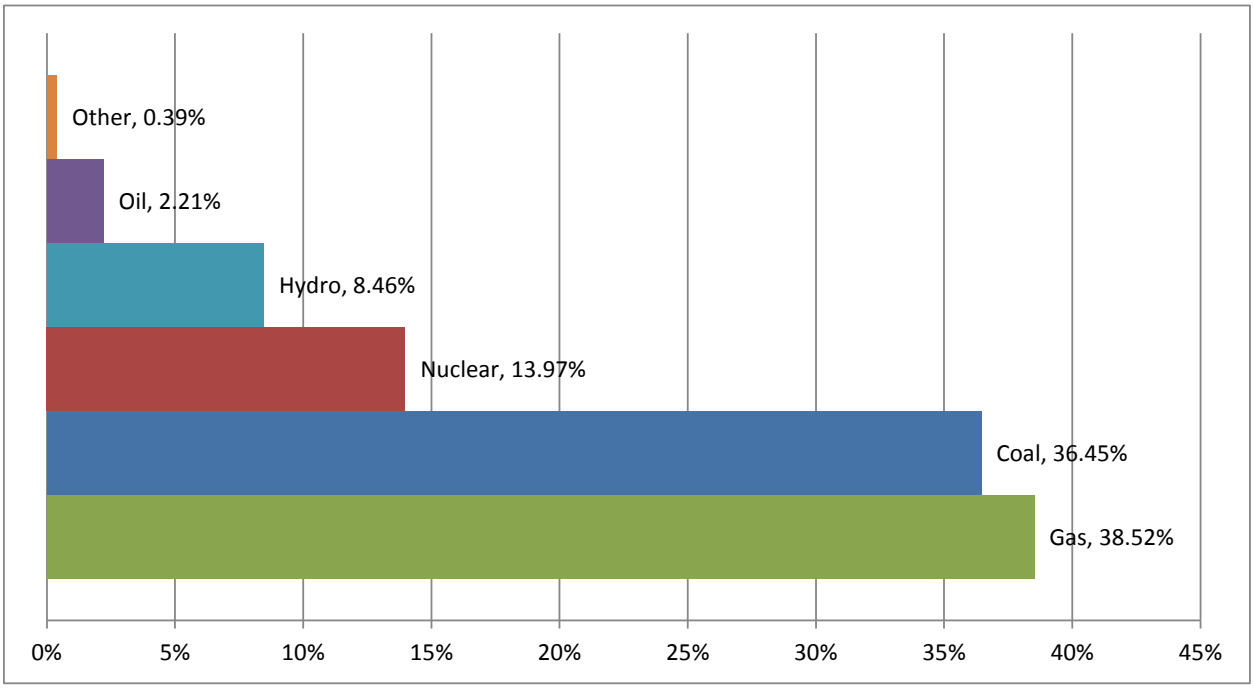
Summer Actual Peak Demand



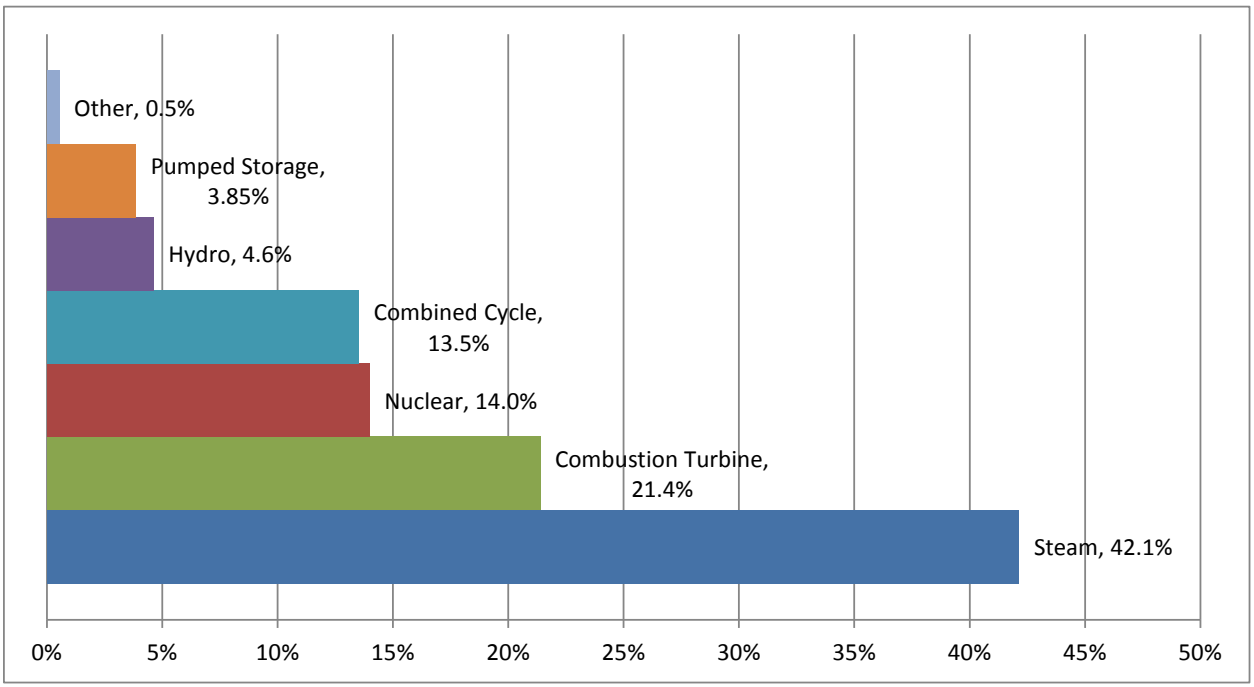
Winter Actual Peak Demand



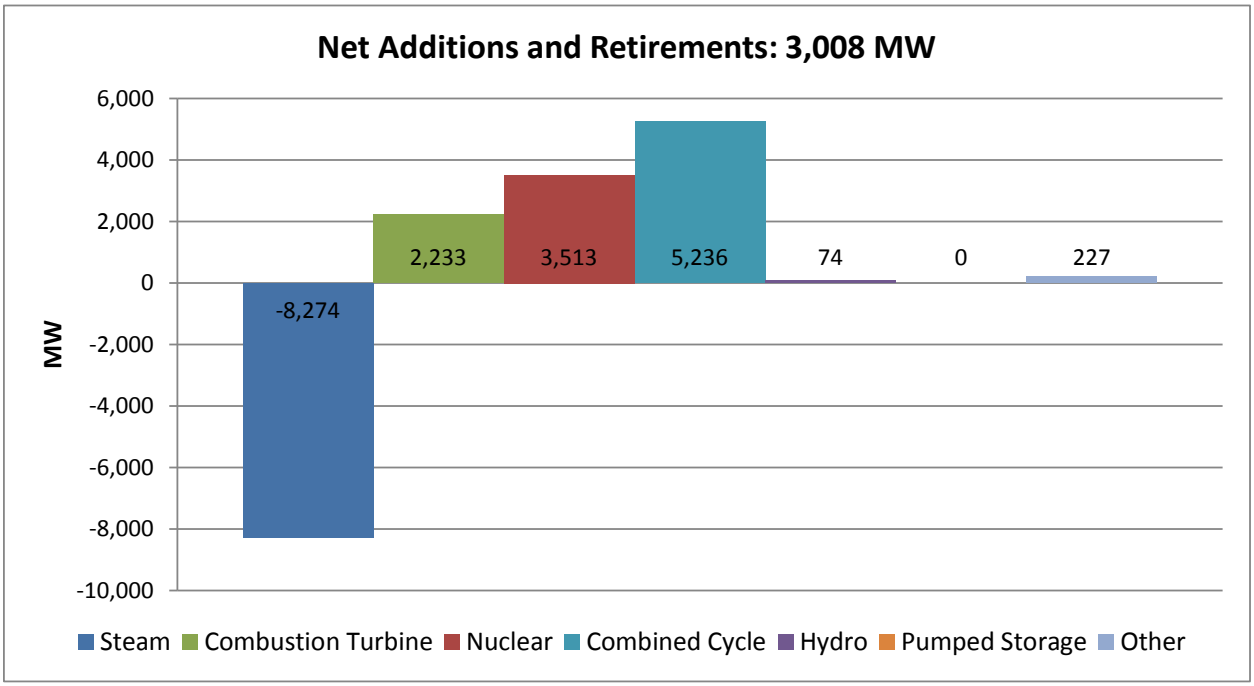
Regional Capacity Breakdown by Fuel Type – 2014



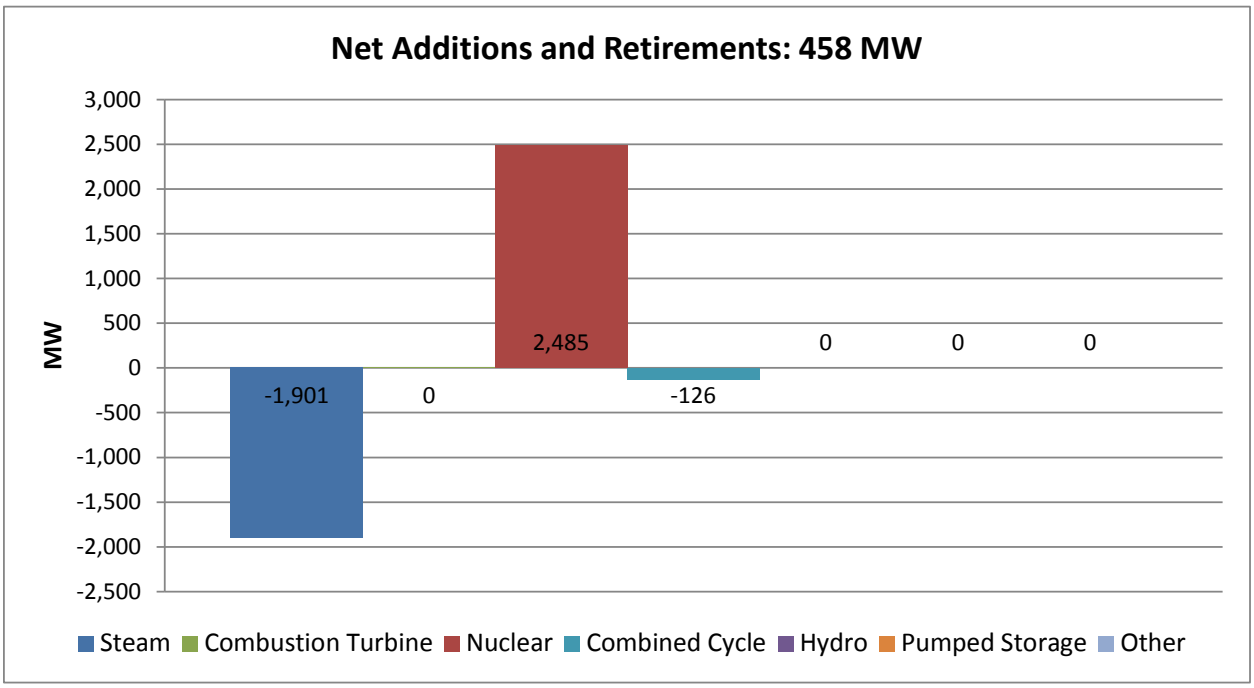
Regional Capacity Breakdown by Technology – 2014



Regional Capacity Additions & Retirements – 2014-2018



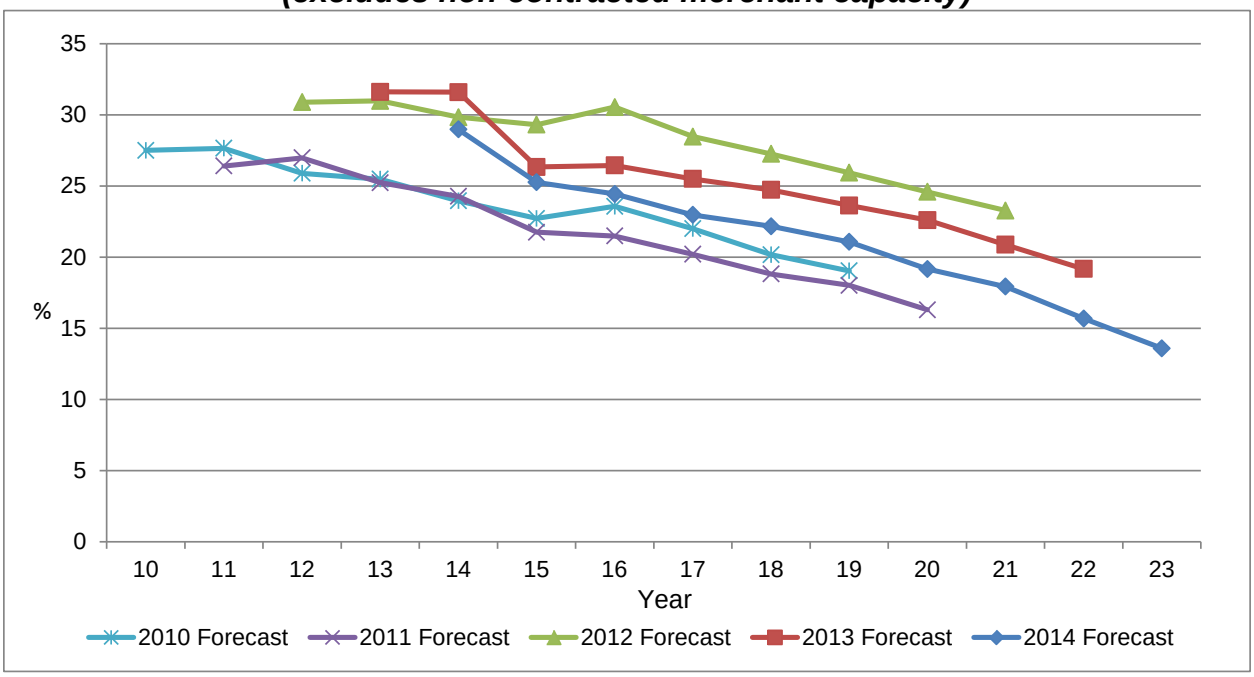
Regional Capacity Additions & Retirements – 2018-2023



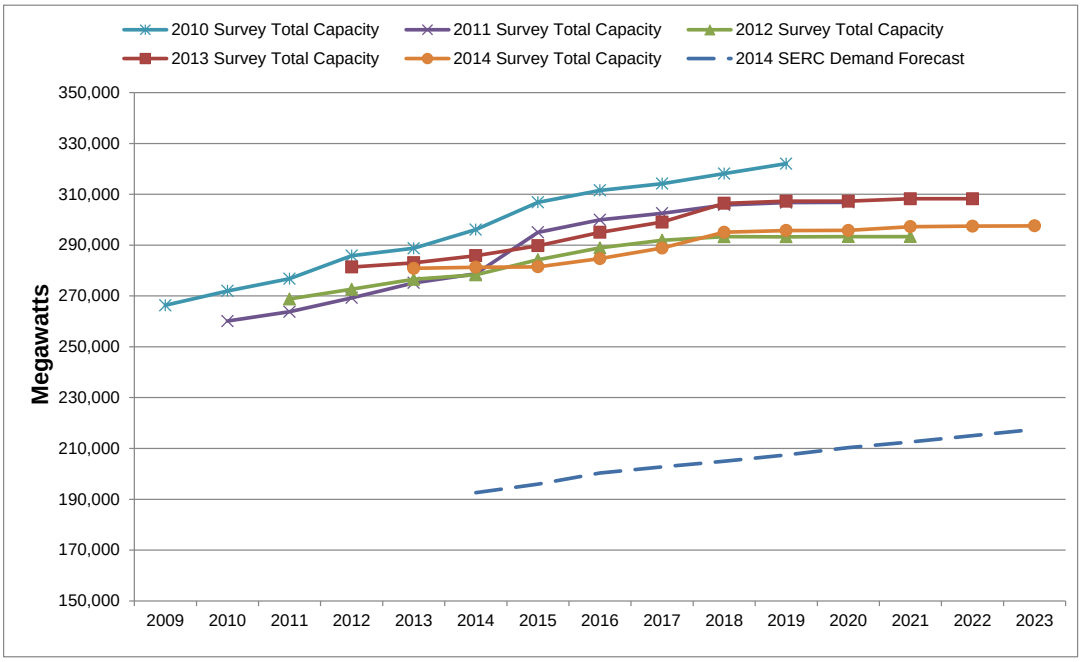
Generation facilities need to be planned and constructed to ensure that aggregate generation capacity keeps pace with the electric demand, and reserve capacity must remain sufficient for grid contingency events. SERC obtains information on the total amount of generation connected within the Region by conducting the Generation Plant Development Survey. In this survey, respondents are asked to report all existing generation connected and all generation development to be connected to the transmission systems within SERC, whether uncommitted or dedicated to serve native load. Generation contracted to serve load within the SERC footprint is included in SERC's firm capacity and related margins.

According to the latest survey, as of December 31, 2013, total generation (including uncommitted generation) connected to the transmission system within the SERC footprint was 281,332 MW, with an additional 458.7 MW of net projected additions planned to be connected by July 1, 2014. Of that total, approximately 270,963 MW were committed to serving load within the SERC Region for summer 2014. Uncommitted generation within SERC totals 10,032 MW. Over the period covered by the 2014 survey, generation capacity additions totaled 16,708 MW versus 26,893 MW projected in the 2013 survey.

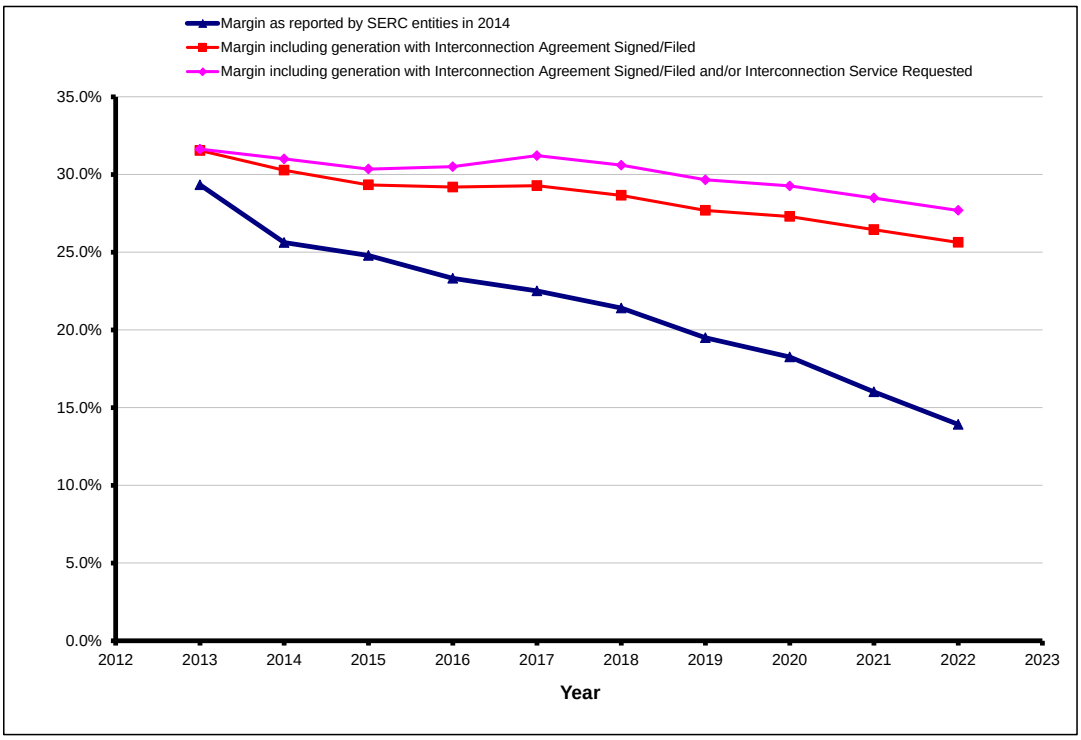
SERC Region Projected Firm Reserve Margins
(excludes non-contracted merchant capacity)



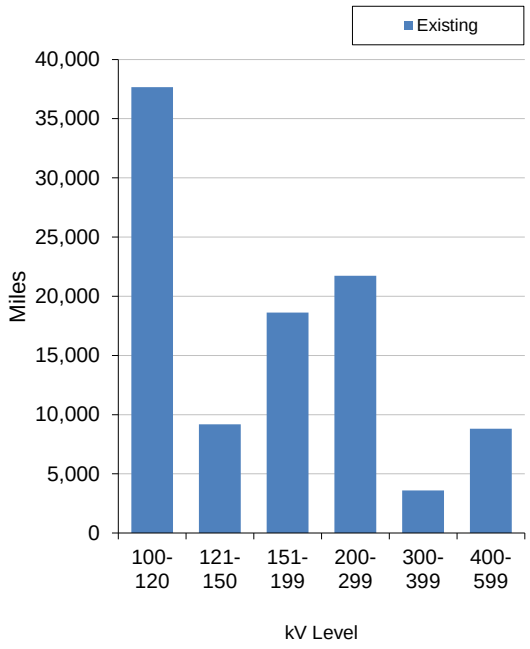
SERC Generation Development

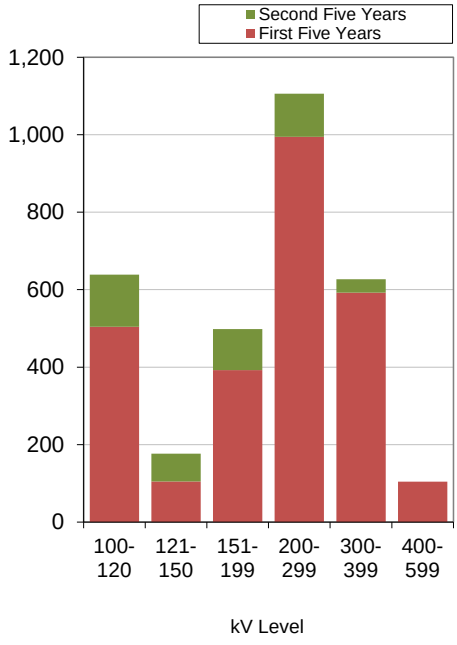


Effects of Generation Development on SERC Reserve Margins

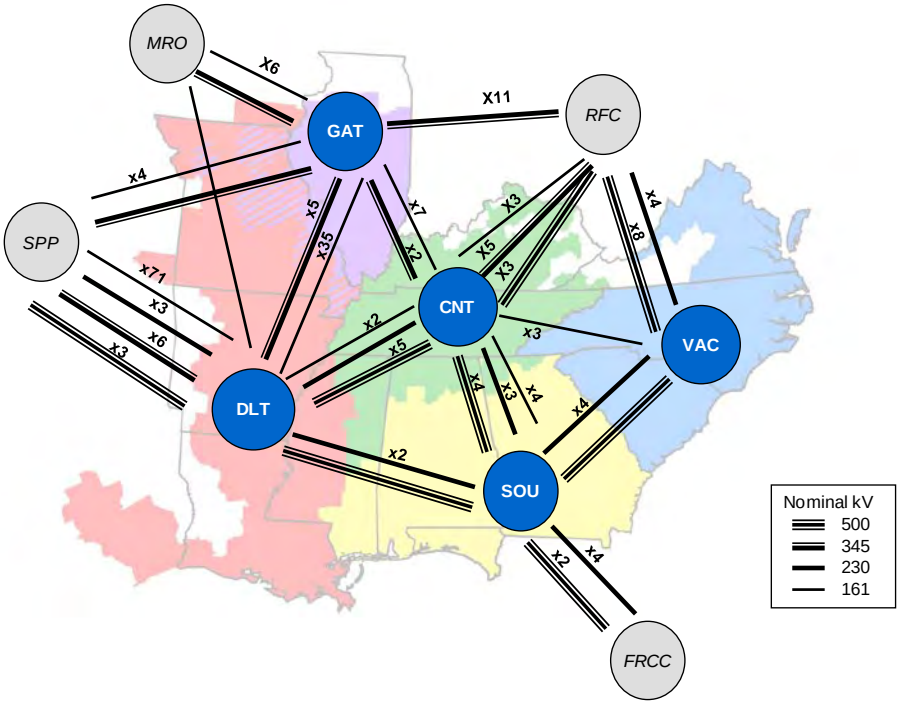


SERC Existing and Planned Transmission Mileage (121kV and above)



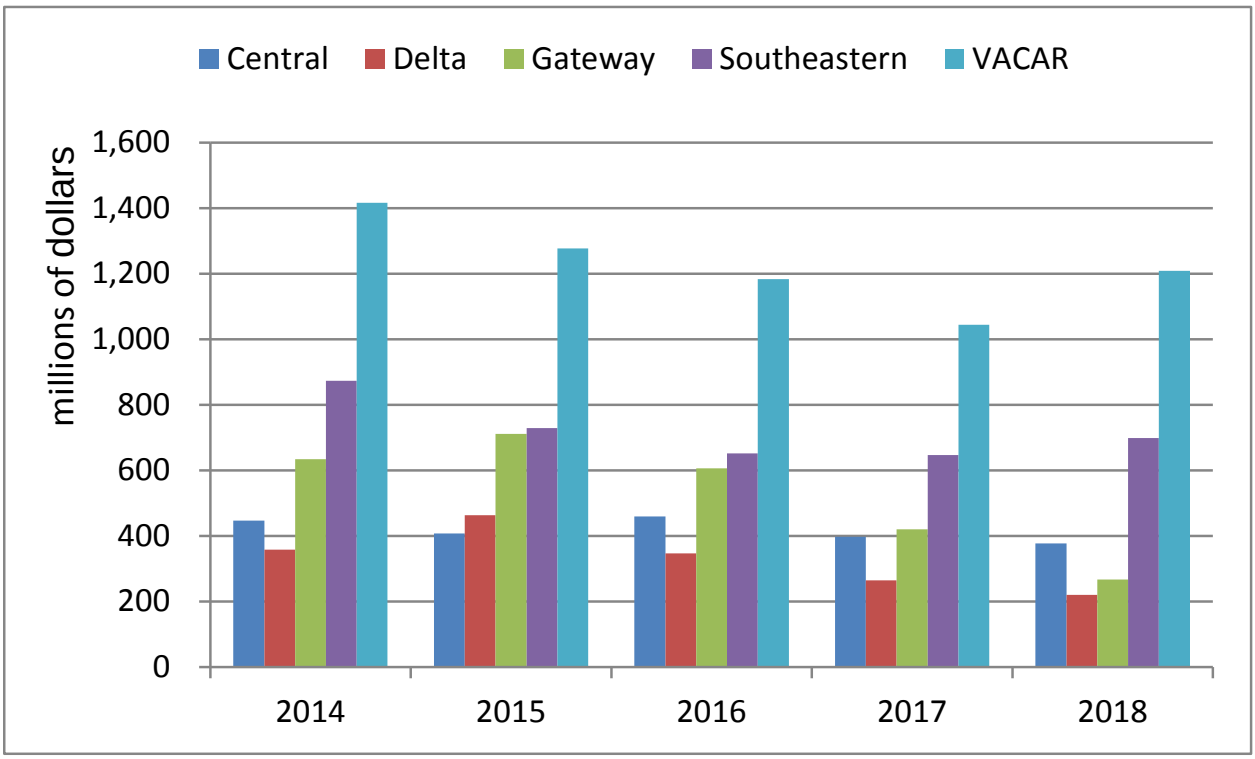


SERC Inter- and IntraRegional Interconnections

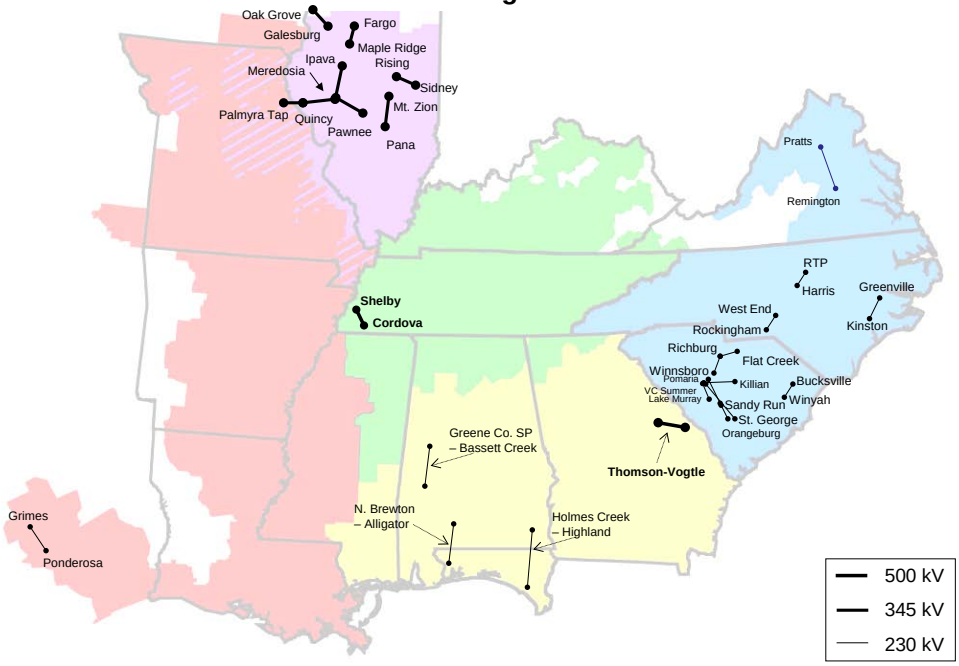


Systems in the SERC Region have developed a robust transmission system with more than 100 transmission connections to their neighbors in the north and west. Additionally, numerous interconnections exist between the five SERC subregions. SERC utilities invested more than $2.3 billion in new transmission lines and system upgrades in 2013. Transmission investments of approximately $13.4 billion in the next five years are planned for the systems within SERC. The projected expenditures from the 2013 survey totaled $15.6 billion through 2017. It is important to note that this transmission expansion is a subset of the total transmission expenditures, which also includes transmission-level substation projects.

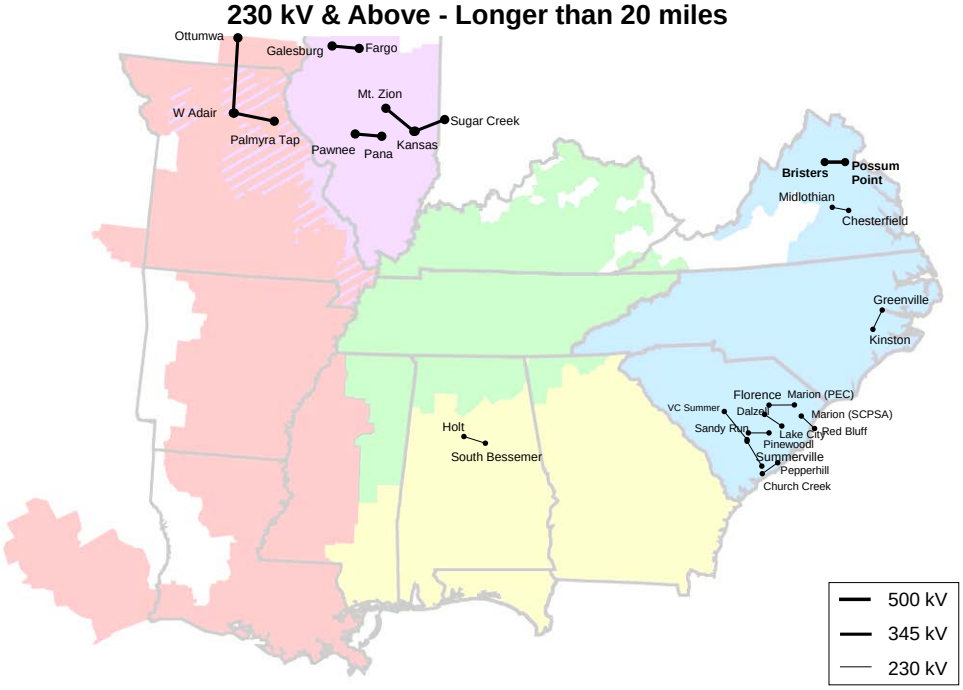
SERC Total Transmission Expenditures



2014 – 2018 SERC Transmission Additions
230 kV & Above - Longer than 20 miles



2019 – 2023 SERC Transmission Additions
230 kV & Above - Longer than 20 miles



The SERC Agreement sets forth the purpose of the organization and the responsibilities of and criteria for membership. Membership in SERC is voluntary, but members recognize a commitment to comply with NERC and SERC policies and principles for the planning and operating of the interconnected electric power system.

Membership Requirements

2.1 General. The Corporation shall be a membership corporation. Entities that meet the eligibility requirements and apply for membership in the Corporation shall hereinafter be referred to individually as a “Member Company” and collectively as "Member Companies".

2.2 Eligibility. Membership in the Corporation is open to any entity in the SERC Region (defined in Section 3.2 below) that is a user, owner or operator of the Bulk Power System and is subject to the jurisdiction of the Federal Energy Regulatory Commission for the purpose of complying with Reliability Standards established under Section 215 of the Federal Power Act and all amendments thereto. Membership in the Corporation is voluntary; however, membership is predicated on mandatory acceptance of the responsibility to promote, support, and comply with Reliability Standards of the Corporation and the North American Electric Reliability Corporation ("NERC"), and to assist the Corporation in its compliance with the terms and provisions of a Delegation Agreement (a “Delegation Agreement”) with NERC, by which NERC delegates authority to propose and enforce Reliability Standards, pursuant to 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions. For purposes of these Bylaws, the terms “Bulk Power System”, “Reliability Standards” and “Regional Entity” shall be as defined in 16 U.S.C. § 824o or the corresponding provisions of any subsequent U.S. Code revisions.

2.3 Termination. A Member Company may terminate its membership in the Corporation by giving the Board of Directors at least thirty (30) days written notice of its intent to terminate such membership (such Member Companies shall hereinafter be referred to as "Terminated Member Companies"). Terminated Member Companies shall nevertheless continue to be liable for any and all obligations incurred prior to the end of the calendar year in which such notice is given, including, but not limited to, the obligation to pay a pro rata share of any Corporation expense. In addition to termination of membership by the Member Company, the Board of Directors, following notice to the Member Company, may terminate the membership of a Member Company if in the judgment of the Board of Directors that Member Company has violated its obligations and responsibilities to the Corporation. The termination of the membership of a Member Company by the Board of Directors shall require a Supermajority vote, as defined in these Bylaws.

2.4 Sectors. Each Member Company shall be classified by the Executive Committee in one of the following seven (7) Sectors (each a "Sector", and collectively, the "Sectors"):

(a) Investor-Owned Utility Sector – This Sector includes any investor-owned entity with substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission or distribution.

(b) Federal/State Sector – This Sector includes any U.S. federal entity that owns and/or operates electric facilities and/or provides balancing authority services, in any of the asset categories of generation, transmission, or distribution; or any entity that is owned by or subject to the governmental authority of a state and that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state.

(c) Cooperative Sector – This Sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities.

(d) Municipal Sector – This Sector includes any entity owned by or subject to the governmental authority of a municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating or purchasing electricity for sale at wholesale to their members.

(e) Marketer Sector– This Sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in the SERC Region on a physical or financial basis.

(f) Merchant Electricity Generator Sector – This Sector includes any entity that owns or operates an electricity generating facility or provides balancing authority services for such entities. This includes, but is not limited to, small power producers and all other non-utility producers such as exempt wholesale generators who sell electricity at wholesale.

(g) ISO-RTO Sector – This Sector includes any entity that operates a FERC approved ISO or RTO.

The Executive Committee's classification of a Member Company in a particular Sector may only be changed by the Executive Committee.

2.5 **Transfer of Membership.** A Member Company may not give or otherwise transfer its membership, except to a successor that becomes a Member Company in accordance with the terms and conditions of these Bylaws, and provided that the successor continues to meet its predecessor's obligations.

2.6 **Powers.** Notwithstanding any other provisions of these Bylaws, except for the appointment of Directors as provided in Section 4.2 below, Member Companies shall be non-voting members and shall have no power or authority or right to vote with respect to the actions of the Corporation, specifically including, but not limited to, the dissolution or merger of the Corporation.

Current SERC Member Listing

Investor-Owned Utilities (13)

Alabama Power Company (S)
Ameren Services Company (G)
Duke Energy Carolinas (V)
Duke Energy Progress, Inc. (V)
Entergy (D)
Florida Power & Light Company
Georgia Power Company (S)
Gulf Power Company (S)
LG&E and KU Services Company (C)
Mississippi Power Company (S)
South Carolina Electric & Gas Company (V)
Southern Company Services, Inc. (S)
Virginia Electric and Power Company (DP, LSE, TO) (V)

Cooperatives (14)

Associated Electric Cooperative, Inc. (D)
Big Rivers Electric Corporation (C)
East Kentucky Power Cooperative (C)
Georgia System Operations Corporation (S)
Georgia Transmission Corporation (S)
Louisiana Generating, LLC (D)
North Carolina Electric Membership Corporation (V)
Oglethorpe Power Corporation (S)
Old Dominion Electric Cooperative (V)
Piedmont Electric Membership Corporation (V)
PowerSouth Energy Cooperative (S)
Prairie Power, Inc. (G)
South Mississippi Electric Power Association (D)
Southern Illinois Power Cooperative (G)

Municipal (9)

Alabama Municipal Electric Authority (S)
City of Columbia, MO (G)
City of Springfield, IL (G)
ElectriCities of North Carolinas, Inc. (V)
Fayetteville Public Works Commission (V)
Illinois Municipal Electric Agency (G)
Municipal Electric Authority of Georgia (S)
Owensboro, KY Municipal Utilities (C)

Federal/State Systems (3)

South Carolina Public Service Authority (V)
Southeastern Power Administration (C,S,V)
Tennessee Valley Authority (C)

Merchant Electricity Generators (8)

Brookfield Smoky Mountain Hydropower, LLC (C)
Calpine Corporation
Cogentrix Energy Power Management, LLC
Dynegy, Inc
Electric Energy, Inc.
Entegra Power Group LLC
Exelon Generation Company, LLC - Constellation.
Occidental Chemical Corporation

Marketers (5)

ACES Power Marketing
Alcoa Power Generating, Inc.
DTE Energy Trading, Inc.
Tenaska Power Services Co.
The Energy Authority, Inc.

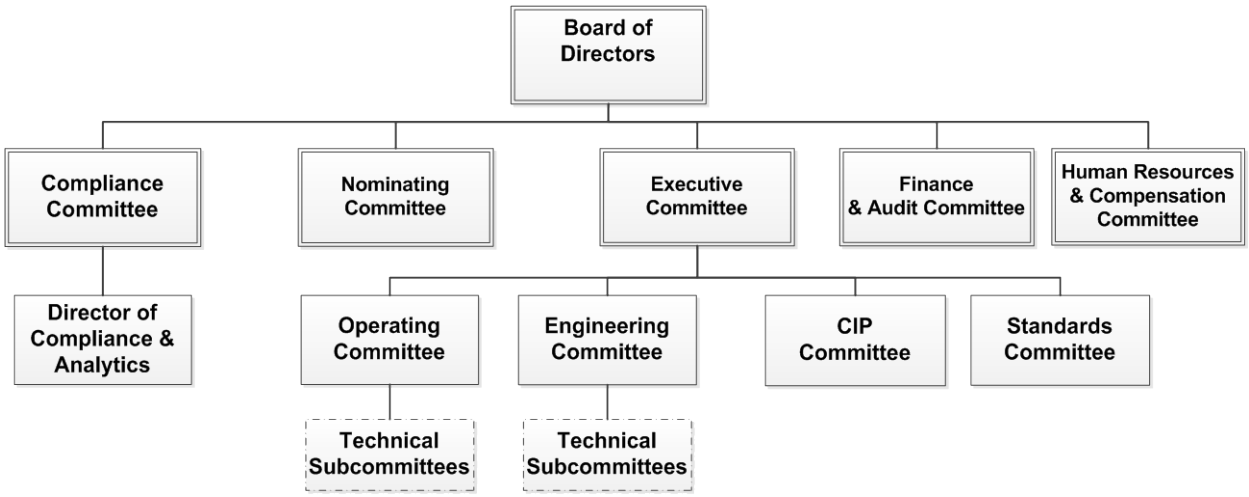
RTO/ISO (3)

Midwest Independent Transmission System Operator, Inc.
PJM Interconnection, LLC
Southwest Power Pool, Inc.

Subregional Affiliation

(C) - Central Subregion **(S)** - Southern Subregion
(D) - Delta Subregion **(V)** - VACAR Subregion
(*G*) - Gateway Subregion

Stakeholder Organizational Chart



SERC Standing Committee Officers

Board of Directors

Chair
Caren Anders, Duke Energy Progress, Inc.

Vice-Chair
Greg Ford, Georgia System Operations Corporation

Secretary-Treasurer
Marion Lucas, Alcoa Power Generating, Inc.

Engineering Committee

Chair
Doug McLaughlin, Southern Company Services, Inc.

Vice-Chair
Clayton Clem, Tennessee Valley Authority

Operating Committee

Chair
Stuart Goza, Tennessee Valley Authority

Vice-Chair
Sammy Roberts, Duke Energy Progress, Inc.

Critical Infrastructure Protection Committee

Chair
Ed Goff, Duke Energy Progress

Vice-Chair
Cynthia Hill-Watson, Tennessee Valley Authority

Attachment D

SPP Annual Looking Forward Report:

Strategic Issues Facing the Electricity Business

Boston Pacific

SOUTHWEST POWER POOL
ANNUAL LOOKING FORWARD REPORT:
Strategic Issues Facing the Electricity Business

Prepared by:

BOSTON | PACIFIC
COMPANY, INC.

As an Independent Advisor
to the SPP Board of Directors

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Craig R. Roach, Ph.D.
Vincent Musco
Sam Choi
Andrew Gisselquist

April 20, 2015

This Report is dedicated to the memory of Stacy Duckett.

Table of Contents

ABOUT BOSTON PACIFIC COMPANY, INC.

Boston Pacific Company, Inc. (Boston Pacific) is a consulting and investment services firm, located in Washington, D.C., specializing in the electricity and natural gas industries. For 28 years, we have provided information and insight to our clients who span the full range of stakeholders: state regulatory commissions, regional transmission organizations, energy consumers, competitive power producers, electric utilities, gas pipeline companies, and electric transmission companies. We are nationally recognized experts on the electricity business as documented by our service as expert witnesses throughout North America. Boston Pacific also is an industry leader in designing and monitoring major power procurements of every type for state commissions across the country, as well as open seasons for merchant transmission lines. In addition, Boston Pacific has extensive, hands-on experience with a full range of power technologies including clean coal, on- and off-shore wind, geothermal, waste-to-energy, solar photovoltaics, and natural gas-fired combined-cycle. For 11 years, we have served as an independent advisor to the Board of Directors of the Southwest Power Pool Regional Transmission Organization (RTO) on a full range of issues related to market design and operation.

For more information on Boston Pacific, please visit us at www.bostonpacific.com.

DISCLAIMER

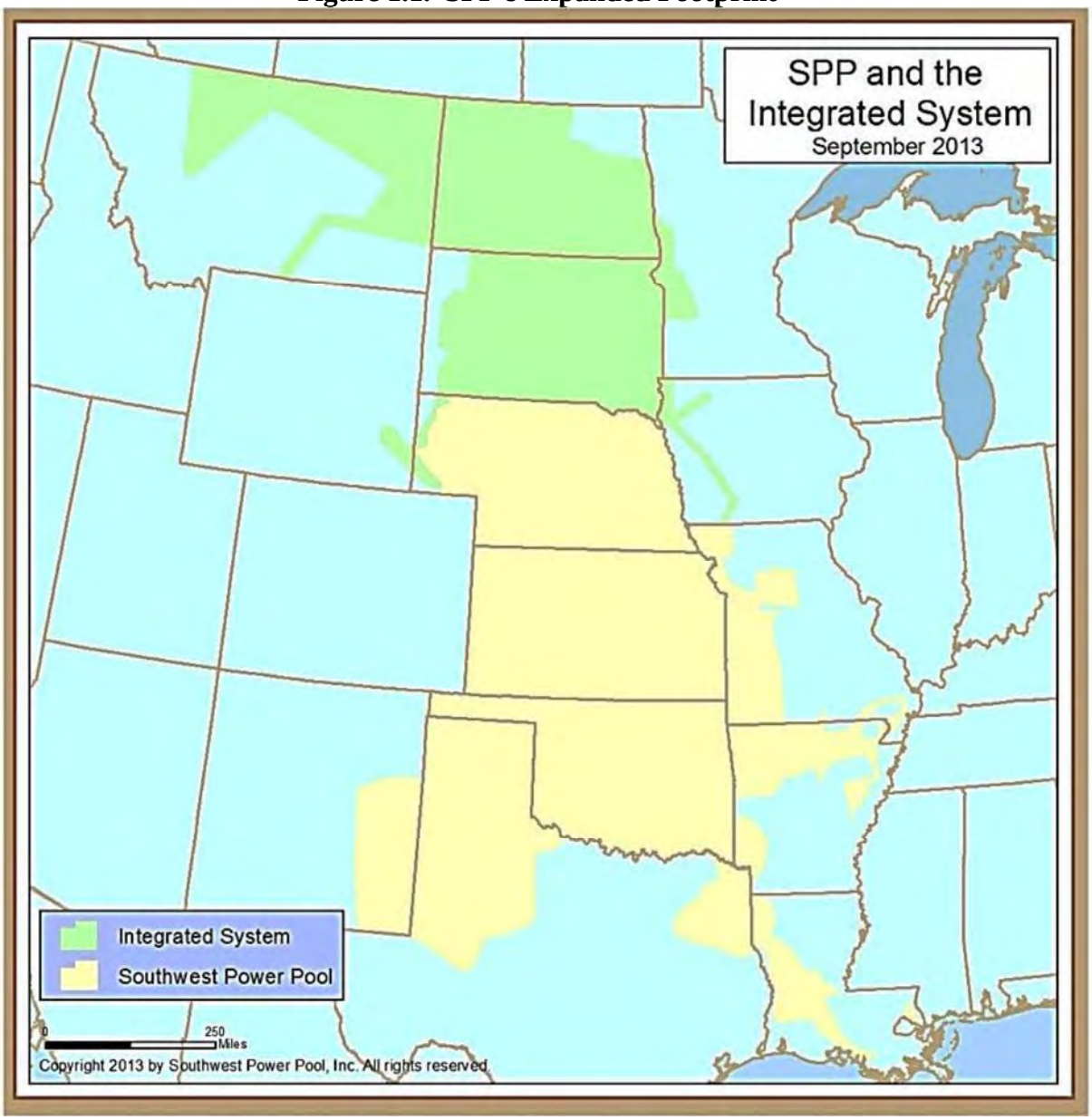
I. Executive Summary

This is the fifth year in which Boston Pacific Company, Inc. (Boston Pacific) has prepared a separate *Annual Looking Forward Report* for the Southwest Power Pool (SPP) Board of Directors (Board). As with the first four, this report is intended to contribute to the longer-term strategic planning by the Board. To that end, we focus on broad market and regulatory events that (a) could potentially have a significant impact on SPP's markets and/or (b) could require the Board's special attention. Boston Pacific greatly appreciates the input to and guidance for this report provided by the Board's Oversight Committee.

This year's report comes at an exciting time for SPP, which has recently expanded its footprint to include the Basin Electric Power Cooperative (Basin), the Heartland Consumers Power District (Heartland), and the Western Area Power Administration's Upper Great Plains Region (UGP) (collectively, the Integrated System). These new members add to SPP over 3 million new customers and about 9,500 miles of transmission lines located in seven states;[1] the addition increases SPP's size by approximately 20 percent. While these entities will not be full members until October 2015 following the completion of various transmission upgrades, joining SPP was estimated to provide $310 million in net benefits over the first ten years. Figure 1.1 shows SPP's expanded footprint to include the Integrated System.

[1] The seven states in the Integrated System include portions of North Dakota, South Dakota, Montana, Wyoming, Minnesota, Iowa, and Nebraska.

Figure 1.1. SPP's Expanded Footprint



This year's Report covers eight topics: (a) an update on EPA's continued environmental campaign, (b) an update on the shale gas revolution, (c) an update on the changing utility model, (d) physical grid security, (e) federal-state jurisdictional issues in the electricity business, (f) thoughts on a framework for considering transmission investments, (g) smart grid, and (h) the prospects for exporting power from SPP's renewable energy resources, especially wind.

A. EPA's Continued Environmental Campaign

The future of coal-fired generation is largely being determined by Environmental Protection Agency (EPA) regulations. Four primary EPA regulations are reshaping the power

sector by causing the shutdown or retrofitting of coal-fired generation: (1) the Cross-State Air Pollution Rule (CSAPR); (2) Mercury and Air Toxics Standards (MATS); (3) the Cooling Water Intake Structures regulation, otherwise referred to as 316(b); and (4) the disposal of Coal Combustion Residuals from Electric Utilities regulation (CCR). The U.S. Government Accountability Office (GAO) recently confirmed that the estimated impact that these regulations will have on coal-fired power generation is at the high-end of previous estimates. In total, roughly one-third of all coal plants are estimated to be retired or retrofitted as a result of these regulations.[2]

Additionally, EPA's proposed regulations on carbon emissions from new and from existing power plants could place even more pressure on coal units and impact other types of fossil fuel resources, too. EPA's proposed Clean Power Plan aims to achieve a 30 percent reduction in carbon dioxide (CO_2) emissions from the power sector by 2030 as compared to emissions in 2005.[3] It would limit CO_2 emissions from *existing* power plants and would essentially require carbon capture and sequestration for *newly built* coal-fired generation. In terms of the possible impact of compliance with the Clean Power Plan, the North American Electric Reliability Corporation (NERC) raised concerns about reliability and estimated that implementation of the Clean Power Plan could result in a reduction in capacity between 108 and 134 gigawatts (GW) by 2020.[4] That is roughly 2.5 to 3 times the estimated 42 GW of retirements caused by the four EPA regulations listed above.[5] Although, as a counterpoint, we note that a report released by the Brattle Group concluded that there is sufficient flexibility in the Clean Power Plan such that reliability is unlikely to be materially affected.

As to the cost of compliance with EPA's Clean Power Plan, studies conclude that *regional* compliance strategies would be cheaper than *state-by-state* compliance plans. The Midcontinent Independent System Operator (MISO) conducted analysis of the proposed Clean Power Plan and found that regional compliance options could save approximately $3 billion annually, as compared to compliance plans that are consistent with EPA's state-by-state "building blocks" approach.[6] PJM Interconnection (PJM) also came to the same conclusion that MISO did, in that regional approaches were seen to be less expensive than state-by-state approaches. In particular, state-by-state compliance would be nearly 30 percent more expensive in 2020 than a regional approach – nearly $45 billion versus $35 billion.[7] Given that the regional approach appears to be the lower cost option for compliance, we believe that it could be constructive for SPP to facilitate a regional compliance plan with its member states if the Clean Power Plan regulation is finalized.

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[2] According to the GAO report in 2012, there was 309,680 MW of coal-fired capacity. *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*, GAO, August 2014, 5, 15.
[3] *Overview of the Clean Power Plan: Cutting Carbon Pollution from Power Plants*, U.S. Environmental Protection Agency, June 2014.
[4] *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review*, NERC, November 2014, 2.
[5] Ibid.
[6] *GHG Regulation Impact Analysis – Initial Study Results*, MISO, September 17, 2014.
[7] Sotkiewicz and Abdur-Rahman, EPA's Clean Power Plan Proposal Review of PJM Analyses Preliminary Results, PJM, November 17, 2014, 56.

B. The Shale Gas Revolution

Based on current metrics, there is no slowdown in the momentum of the shale gas revolution. The growth story continues and is being underpinned by (a) increasing shale gas production, which grew six-fold from 2007 to 2013, (b) shale gas displacing some conventional gas production and making up 40 percent of total natural gas extracted in 2013,[8] and (c) dramatic growth in shale gas reserves with total proved natural gas reserves having grown by 80 percent from 2003 to 2013 and shale gas reserves accounting for 45 percent of total proved reserves in 2013.[9] As a result, natural gas prices, though volatile, remain relatively low at about $3/MMBtu at Henry Hub through the first two months of 2015.[10] Furthermore, this growth in natural gas production has been met by growth in demand, with electricity from natural gas-fired power generation increasing as a share of total generation from 18 percent to 30 percent in 2012.[11]

Though there is no arguing the past and current strength of the shale gas revolution, there is debate about exactly how robust its future will be. Mainstream projections, as represented by the U.S. Energy Information Administration's (EIA's) 2014 Annual Energy Outlook, are that shale gas production will continue to grow through 2040. However, despite that increased production, EIA forecasts natural gas prices to increase by 2.9 percent in real terms per year as production shifts into areas where natural gas recovery is more difficult and costly.[12] In large part, EIA's assumptions about future natural gas production and prices are supported by estimates of significant shale gas reserves and assumptions that advances in technology and successful exploration will continue to produce more recoverable resources. But questions about the nature of shale gas resources below ground is where much of the debate lies. One skeptical analyst, David Hughes, a geoscientist who had spent 32 years with the Geological Survey of Canada, produced an estimate of recoverable reserves in the major shale gas plays that is 39 percent below EIA's estimate.[13]

In addition to below-ground risks, the future of the shale gas revolution also is subject to above-ground risks. Many of these risks concern new regulations for or even bans on hydraulic fracturing. Regulations are likely to arise from worry over impacts on public health, environmental harm, and earthquakes. The potential impact for regulations to limit shale gas production is real, as shown by New York State's ban on hydraulic fracturing announced in December 2014. In addition to regulation, the courts are also involved. Notably, the Oklahoma Supreme Court is hearing a lawsuit that could decide whether shale gas producers can be found liable for earthquakes.

Finally, another above-ground risk that could lead to increased demand and higher natural gas prices is the export of liquefied natural gas (LNG). Thus far, five LNG export terminals have been approved. If, in addition to these five, fourteen other currently proposed

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[8] EIA, *Natural Gas Gross Withdrawals and Production*, release date February 27, 2015.
[9] EIA, *U.S. Crude Oil and Natural Gas Proved Reserves*, Table 8, released December 4, 2014.
[10] EIA, *Henry Hub Natural Gas Spot Price*, release date March 11, 2015.
[11] EIA, *Electric Power Annual*, Table 3.1.A, release date December 12, 2013.
[12] EIA, *Annual Energy Outlook 2014*, April 2014 (2014 EIA Annual Energy Outlook),MT-21.
[13] Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts For a Lasting Tight Oil & Shale Gas Boom*, post carbon institute, October 2014, 15.

terminals are also approved, the combined export capacity could exceed the total amount of natural gas used by the electricity sector in 2013.

C. Update on the Changing Utility Model

In last year's Looking Forward Report, we noted that (a) decentralized technologies have already impacted the operation of the electric power grid, (b) are projected to play a greater role going forward, and (c) though there are concerns about distributed generation becoming an existential threat to the traditional bulk electric system, it may be better to think of decentralized technologies as complements to, not competitors for, the grid. This year, we update our findings to provide the Board with a view of what is happening with decentralization and the attempts to use it to compete with centralized power. While there is no conclusive evidence suggesting that widespread decentralization is imminent, we find constructive activity on a number of fronts that may suggest an emerging challenge to the traditional utility model.

First, increased adoption of and cost reductions in distributed energy technologies – especially solar photovoltaics – mean that they may become cost competitive with centralized generation in some higher-cost jurisdictions for energy generation. Data from the Lawrence Berkeley National Laboratory, for example, suggests that the installed price per watt of solar photovoltaic capacity has fallen 50 percent from 2009 to 2013.[14] Separately, SolarCity, the largest U.S. solar installer, is targeting an installed cost of just $1.20/watt for solar capacity, a 42.6 percent decline from its current costs.[15] Adoption of distributed solar continues to increase, driven by cost reductions, favorable public policy, and lower cost financing through use of securitized products.

Second, through private innovation, new business models are emerging that seek to apply these new technologies to challenge the traditional utility model. These offerings include: (a) efforts by two major American companies – SolarCity and Tesla Motors – to combine distributed solar generation with battery storage; (b) so-called "virtual power plants," which are aggregations of distributed generation, energy storage, and demand-side resources – linked together by smart grid technology – to be a single, dispatchable resource; and (c) new ways to aggregate load resources to offer value to wholesale markets, including an example of a company that is aggregating electric home heating systems to provide frequency response service in PJM.

Third, utilities are starting to feel financial pressure from a combination of (a) competition from decentralized technologies, sometimes driven by public policies like net metering for distributed generation (b) slow demand growth – EIA estimates growth to average just 0.9 percent per year through 2040,[16] and (c) rising capital expenditures to maintain the grid and accommodate environmental compliance. One indicator of this financial pressure comes from Barclays, an international bank, which recently downgraded electric utility bonds, noting in

[14] Lawrence Berkeley National Laboratory, "Tracking the Sun VII," September 2014, 13.
[15] Bullis, "Solar City and Tesla Hatch a Plan to Lower the Cost of Solar Power," *MIT Technology Review*, September 19, 2014.
[16] 2014 EIA Annual Energy Outlook, MT-16.

its analysis that "[i]n the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power…[w]e believe that solar [plus] storage could reconfigure the organization and regulation of the electric power business over the coming decade."[17]

Fourth, some regulators are working to reform the regulatory compact with utilities to encourage the growth of these distributed energy resources. The most complete state regulatory reform effort currently underway is New York's Reforming the Energy Vision initiative, which grants to utilities a new role as Distribution System Platform Providers – essentially an independent system operator for distributed energy resources – so that these new technologies and business models can be incorporated into distribution systems. The initiative also seeks to reform ratemaking to provide utilities with the financial incentives to take on this new role.

D. Physical Grid Security

Two recent, notable events have brought significant attention to and intensified a nation-wide discussion about the vulnerabilities of the grid. In April of 2013, gunmen opened fire at one of Pacific Gas and Electric's substations causing damage to 17 high voltage transformers which led to grid operators having to respond quickly to avert a blackout. In March of 2014, a leaked analysis by the Federal Energy Regulatory Commission (FERC) showed that disabling as few as nine of this type of substation during a time of peak electricity demand reportedly could cause a "coast-to-coast blackout."[18]

High voltage transformers are critical to the grid's operations since they serve as the backbone of the electric grid by handling the bulk of the flow of the nation's electricity. However, recent analysis shows that they are the most vulnerable to an intentional physical attack. This is due to a number of factors, including (a) the sheer size of the equipment making it easy to identify and, therefore, an easy target for a physical attack, (b) its penetrability to gunshots, (c) a lack of security measures and human presence if remotely located, (d) not being easily interchangeable, (e) long manufacturing lead times, (f) high cost, and (g) difficulty in transporting equipment.

Yet, despite the risk from physical attack on high voltage transformers, there are other threats such as storms and earthquakes that could have equal or greater impact with a much higher chance of actually occurring. Accordingly, while we believe that improving defensive measures and deterrents to physical attacks are important, since all future attacks may not be preventable, resiliency should be emphasized. Investments in resiliency such as in redundant transmission lines or substations would allow the affected transmission system to respond and recover faster. In any case, investment decisions should be based on which investments would provide the greatest system-wide net benefits.

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[17] Michael Aneiro, "Barclays Downgrades Electric Utility Bonds, Sees Viable Solar Competition," *Barron's Income Investing*, May 23, 2014.

[18] Paul W. Parfomak, *Physical Security of the U.S. Power Grid: High –Voltage Transformer Substations*, Congressional Research Service, June 17, 2014, 6.

E. Blurred Jurisdictional Lines

In 2013, judges in two separate decisions in U.S. District Court – one in New Jersey, the other in Maryland – ruled that federal law preempted state law with respect to important resource choice decisions. In both cases, the states sought long-term contracts for new generation because of reliability concerns for their ratepayers. The basis for each of these landmark decisions – that FERC alone sets wholesale rates and the states' programs violated the Supremacy Clause of the U.S. Constitution – threatened to upset the longstanding jurisdictional coexistence between state and federal regulators. Since then, there have been other developments in the jurisdictional split between the states and the federal government.

First, in the New Jersey and Maryland cases, both states have petitioned the U.S. Supreme Court for consideration of the two decisions. If unsuccessful, states may no longer be able to procure new generation even when faced with reliability concerns. This could be problematic in states with federal capacity markets. As a backdrop, note that, according to the American Public Power Association, 97.6 percent of new capacity that was built in 2013 was either utility- or customer-built, or backed by a long-term, power purchase agreement, while just 0.1 percent of the new capacity was constructed for sale into RTO markets without any supplemental assistance.[19] Moreover, the courts' decisions may endanger other state programs such as full requirements electricity service for default service customers and renewable resources pursuant to state Renewable Portfolio Standards (RPS). This may be all the more reason for states in the SPP footprint to avoid capacity markets altogether and maintain jurisdiction over resource adequacy and new generation.

Second, in May 2014, the D.C. Court of Appeals vacated FERC Order No. 745, which required RTOs and Independent System Operators (ISOs) to compensate demand response providers at full locational marginal prices in the energy market. The Court concluded that demand response is a retail transaction, not a wholesale transaction, and thus is under the sole jurisdiction of the states, not FERC. FERC has appealed the case to the U.S. Supreme Court, arguing that the D.C. Court of Appeals decision threatens significant damage to U.S. electricity markets and throws into question whether FERC has authority to permit the participation of demand response providers in wholesale-electricity markets at all. After the decision, some parties have challenged FERC's regulation of the capacity markets, where demand response participation is substantial.

Third, an emerging potential front in the jurisdictional divide between states and the federal government involves sales from distributed generation. While discussion of distributed generation is dominated by talk of net metering policies, some are raising a more fundamental question: are sales by retail customers with distributed generation resources back to the grid a wholesale or retail transaction? Today, sales from distributed generation resources are considered FERC-jurisdictional, and FERC has rejected efforts by states to regulate some distributed generation. But a recent article in the *Energy Law Journal* argues that FERC cannot claim jurisdictional over wholesale sales from distributed generators that are *intrastate*; that is, both the seller and the buyer are in a single state and on local distribution facilities. These are

[19] "Power Plants are not Built on Spec," American Public Power Association, 2014, 2.

intrastate wholesale transactions that, as result of not being interstate, should be considered state jurisdictional.

Fourth, another emerging potential issue involves RTOs' role in providing service at just and reasonable rates pursuant to the Federal Power Act while also helping states comply with EPA's proposed Clean Power Plan's emissions reductions. So far, we have not seen much evidence suggesting that RTOs will have trouble complying with these two federal standards (if the Clean Power Plan is adopted). For example, the proposed Clean Power Plan offers options for meeting emissions reductions, including pricing carbon, which can be added to a RTO's commitment and dispatch software to encourage the lowest-cost result. However, questions remain over FERC's ability to alter or reject an RTO-proposed compliance plan. Some parties suggest that, at minimum, it may be advantageous for similarly-situated states – like states within the same RTO – to collaborate on developing a uniform compliance strategy, such as a single, regional price for carbon to be included in market dispatch.

F. Thinking About a Framework for Evaluating Transmission Investments

One of the Board's most important functions is reviewing and approving transmission investments. Those investments can be significant: in 2012, 2013, and 2014, SPP has issued "notice to construct" letters for new transmission projects totaling $1.52 billion,[20] $1.64 billion,[21] and $1.48 billion,[22] respectively. More recently, SPP approved another $270 million of additional transmission investment in early in 2015.[23] Complicating this function of the Board are a series of challenging, disparate issues that sometimes lead to debate between reasonable people about whether new transmission is needed and, if so, which project(s) best address the need. In this chapter, we provide the Board with thoughtful intelligence on these issues.

The first issue we identify is the potential for general pushback by customers against paying for additional transmission investments, even when those investments are projected to have benefits. One example comes from Public Service Electric & Gas Company (PSE&G) in New Jersey, where, in the wake of the impact of Superstorm Sandy – $12 billion in lost economic activity and 7,300 job losses[24] – the utility developed its voluntary $3.9 billion "Energy Strong" proposal to strengthen its electric and gas systems against severe weather conditions.[25] Despite findings of benefits commensurate with its costs, PSE&G faced pushback from numerous parties and eventually settled on a scaled-back $1.22 billion investment. Another example of customer attitudes toward paying for additional transmission investment comes from General Electric's Digital Energy group, which in 2014 released the results of its Grid Resiliency

[20] Southwest Power Pool, "2013 SPP Transmission Expansion Plan Report," January 29, 2013, 4.
[21] Southwest Power Pool, "2014 SPP Transmission Expansion Plan Report," January 6, 2014, 7.
[22] Southwest Power Pool, "2015 SPP Transmission Expansion Plan Report," January 5, 2015, 7.
[23] Rich Heidorn Jr., "Falling Oil Prices, Wind Exports Raise Concerns about SPP Transmission Expansion," RTO Insider, January 19, 2015.
[24] Peter Fox-Penner, William Zarakas, "Analysis of Benefits: PSE&G's Energy Strong Program," The Brattle Group, October 7, 2013, xi.
[25] Ibid., viii.

Survey noting that just 38 percent of U.S. adults aged 18 and over are willing to pay an additional $10 per month to ensure the grid is more reliable.[26]

A second issue related to valuing transmission investments is quantifying the value of reliability benefits. Reliability is about reducing outages, and outages can be expensive, costing the U.S. between $20 billion and $150 billion annually.[27] Estimating the value of added reliability can be done through the use of metrics – such as the value of lost load – that seek to measure the economic value from avoiding outages. (SPP uses such metrics in its planning.) These metrics can be imperfect, however, as they can be volatile and dependent on assumptions.

A third issue is the accommodation of renewable power exports. Moving remotely-located wind and solar to load centers outside of SPP typically requires new transmission investment, and it should be of no surprise that SPP customers may have concerns in paying a share of the costs of this investment. We tee up some fair questions related to exports, such as: Are exporters of SPP wind (and the importing buyers in another control area) being allocated their fair share of transmission upgrades and firm transmission service costs through the interconnection process and through paying for firm transmission service? We also note that one way to bypass the complexities of cost allocation for grid expansion projects to support SPP wind power exports is through the use of high voltage direct current (HVDC) transmission projects.

A fourth issue challenging transmission planners is load forecasting, one of the most important variables in a transmission plan and one that is inherently uncertain and that can vary substantially by region. We have seen concerns that transmission planners' forecasts – or those by its members – may be too high, leading to overinvestment in transmission. This places a premium on the importance of (a) regularly updating (and sharing) load forecasts for SPP member load serving entities and (b) using sensitivity analyses on load when the Board considers proposals for new transmission investments.

Lastly, we consider the issue of decentralized technologies' potential competition to provide services typically reserved for new transmission investments. There is what we would term some "intelligent chatter" from credible voices suggesting decentralized solutions may be around the corner, including some promising examples of storage and microgrid investment and performance. However, there also are credible sources of caution about the effectiveness of decentralized technologies, especially in displacing grid services. London Economics, for example, concludes that decentralized technologies may only be able to provide partial services as compared with full network transmission service, which provides the full suite of energy, capacity, and ancillary services on a continuous basis.[28]

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[26] GE Digital Energy, "Grid Resiliency Survey," August 14, 2014.
[27] Johannes Pfeifenberger, "Reliability and Economics: Separate Realities or Part of the Same Continuum?," The Brattle Group, Presented to the Harvard Electricity Policy Group, December 1, 2011, 2.
[28] Julia Frayer, Evan Wang, "A WIRES Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process," London Economics International LLC, on behalf of the Working Group for Investment in Reliable and Economic Electric Systems, October 2014, 12-13.

G. Smart Grid

Over the past several years, there has been a relative surge in smart grid investment, mainly due to a joint cost sharing program between the private sector and the federal government that began in 2009. The electricity industry spent $18 billion on smart grid technologies from 2010 to 2013. Nearly half of that amount came from investments made under the American Recovery and Reinvestment Act of 2009 (ARRA), totaling about $8 billion.

While "smart grid" is a broad term that can refer to a range of technologies, we focus here on advanced metering infrastructure (AMI) and, in particular, smart meters, as it has been the most popular application of smart grid technology. Its primary benefit is that it can facilitate two-way and real-time communications between the utility and the customer. Such technologies, if adopted by enough customers, can have an impact by reducing peak electricity demand and, thereby, potentially deferring new capacity needs through various time-based rate programs. Oklahoma Gas and Electric Company (OG&E) ran a pilot program to test a new time-based rate program over a two-year period. The program resulted in peak demand reductions and an average bill reduction of $150 per customer during the summer. Due to the favorable results, OG&E stated that it would roll out the program to "20% of their customers (120,000) by 2016, with the aim of deferring investment in about 170 MW of power plant capacity."[29]

While AMI has seen impressive growth over the past several years, a big part of it has been due to ARRA funding which will end in 2015. Given that, there are questions about whether the industry will be able to maintain momentum. Other issues such as cybersecurity will play an important role in further customer adoption of smart grid technologies. Despite these issues, AMI, if deployed effectively, can promote the centralized grid by making it more efficient, reliable, and resilient. Therefore, we recommend that the SPP Board continue to communicate with its members to: (a) see what type of efforts, if any, they have implemented with respect to smart grid and (b) if they have made such efforts, see how SPP can add value to its members' smart grid investments.

H. Wind (and Solar) Exports from SPP's Footprint

SPP has been described as the "Saudi Arabia" of wind resources and may soon have a substantial amount of solar power. While SPP uses much of that wind energy internally – wind provided 11 percent of total generation in 2013 and provided as much as 33.4 percent of total SPP load on a single day in 2013[30] – it is natural to consider export possibilities to areas less rich in renewable resources. In this chapter, we explore that opportunity for exports, focusing particularly on sales to the southeast. We explore issues of (a) supply, (b) demand, and (c) transport of renewable exports and conclude with a potential next step for SPP's consideration.

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[29] United States Department of Energy, *Demand Response Defers Investment in New Power Plants in Oklahoma*, April 2013.

[30] Southwest Power Pool, *2013 State of the Market*, May 19, 2014 (2013 SPP State of the Market Report), 36.

Regarding supply, the prospects for exports are bright. SPP is in a geographical sweet spot with between 60,000 MW and 90,000 MW of wind potential[31] and strong solar potential – especially in eastern New Mexico – where approximately 2,000 MW have recently been added to the SPP interconnection queue.[32]

Regarding demand, however, challenges abound. Only one southeastern state – North Carolina – has a renewable portfolio standard. And, though Production Tax Credit (PTC)-eligible wind – which according to the Lawrence Berkeley National Laboratory averaged a 2.1 cents per kWh price in 2013[33] – could be economically attractive in the southeast, the total cost of wind must also include the cost of transmission, which can be significant. SPP's wind may, however, also provide economic benefits to the southeast through diversification. A recent IHS study found that diversification saves U.S. ratepayers $93 billion per year.[34] Because the southeast states have relied on expensive clean coal and nuclear projects to address environmental policies, they now may be more open to a different approach.

Regarding transport, it is likely that SPP will need additional transmission expansion to accommodate significant amounts of exports, as evidenced by SPP's own scenario analysis in its transmission planning process. One way to export wind is over the alternating current (AC) system, which could provide reliability benefits in SPP (through a more robust grid) and a greater sharing of the costs of such projects among a larger number of beneficiaries. However, such projects may be expensive, may require expanded interregional coordination with SPP's neighbors, and may test system operators' ability to maintain reliable grid operations despite higher wind penetration. A second way to export wind would be through new HVDC transmission projects, which offer a less complex cost allocation and lesser system impacts. However, HVDC projects can be expensive and difficult to site and permit.

Going forward, SPP can begin by considering its own value proposition for wind. The primary benefit to SPP states from additional wind exports will likely be economic, in the form of new jobs in states like Oklahoma, Kansas, Texas, and Nebraska. If SPP considers it worthwhile to pursue wind exports, it may consider playing the role of facilitator of further discussions between developers, policymakers, legislators, and utilities by hosting a free-of-charge expo in a major target market city in the Southeast, which could be funded, attended, and staffed by wind and transmission developers seeking to secure buyers for SPP export projects. Developers could use the opportunity to demonstrate the benefits of SPP's renewable power.

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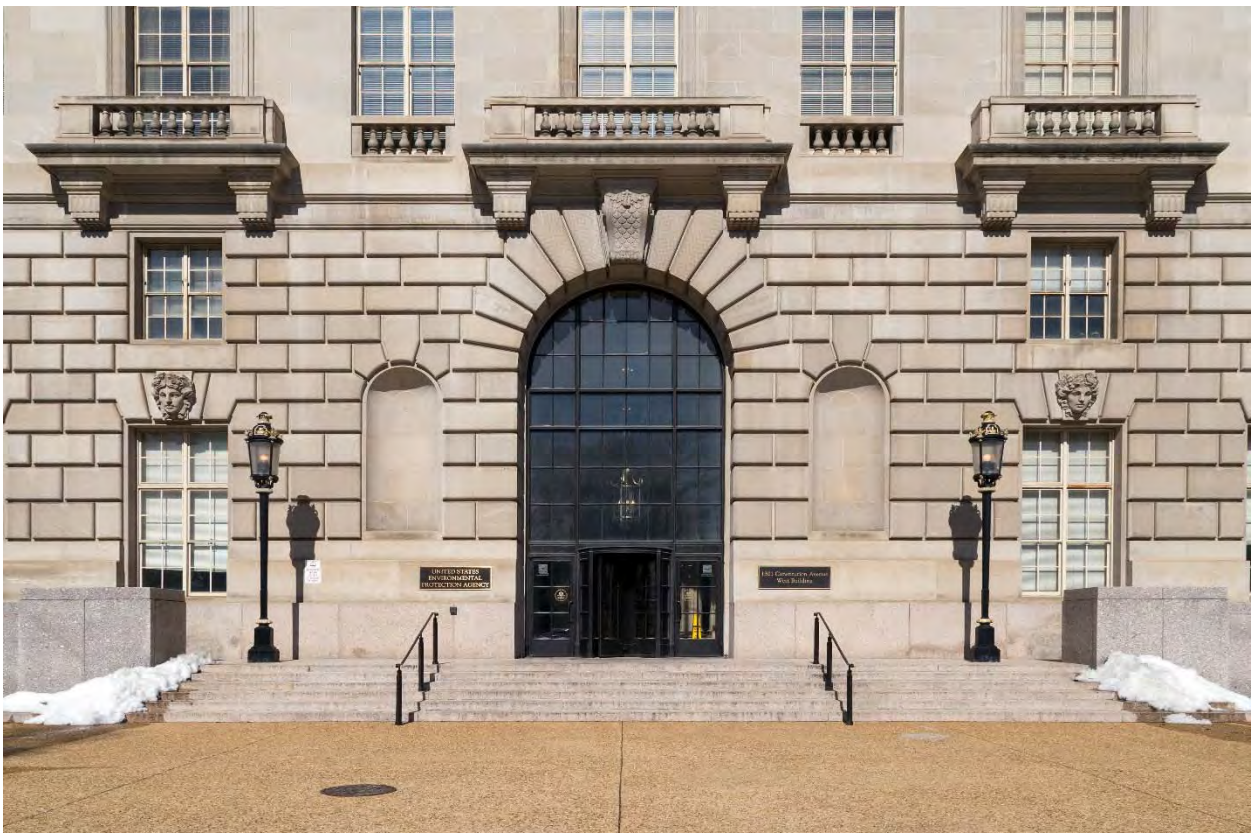
[31] Southwest Power Pool, "SPP 101," 76.
[32] Comments of Jay Caspary, available at https://youtube.com/watch?v=JWXGGI1JrjU.
[33] "2013 Wind PPA Prices In U.S. Interior Averaged 2.1 Cents/kWh (Windpower 2014)," Clean Technica, May 8, 2014.
[34] IHS Energy, *The Value of US Power Supply Diversity*, July 2014, 5.

II. EPA's Continued Environmental Campaign (An Update)



EPA regulations continue to be a driving force in the shutdown or retrofitting of coal-fired generation which is reshaping the power sector. This chapter first updates the status and impacts of key EPA regulations, beginning with an update on four regulations that primarily affect coal-fired generation: (1) the Cross-State Air Pollution Rule, or CSAPR; (2) Mercury and Air Toxics Standards, or MATS; (3) Cooling Water Intake Structures regulation, otherwise referred to as 316(b); and (4) Disposal of Coal Combustion Residuals from Electric Utilities regulation, or CCR. According to estimates from the GAO, roughly one-third of all coal plants will be retired or retrofitted as a result of these regulations.

The chapter then turns to the status and estimated impacts of EPA's proposed regulations on carbon emissions from new and existing power plants. State and regional energy regulators and other organizations are studying the impacts of these regulations, and how best to comply. The analyses covered in this chapter make two things clear. First, the impact of these regulations on carbon emissions may be several times as large as the other regulations combined. It is possible that every large fossil-fueled power plant will be affected by these regulations,

especially if states decide to implement regulations with a cap-and-trade approach. Second, as to the regulations on existing power plants, called EPA's Clean Power Plan, several initial impact analyses agree that regional compliance strategies would be cheaper than state-by-state compliance plans. RTOs/ISOs may have a role in implementing regional compliance strategies.

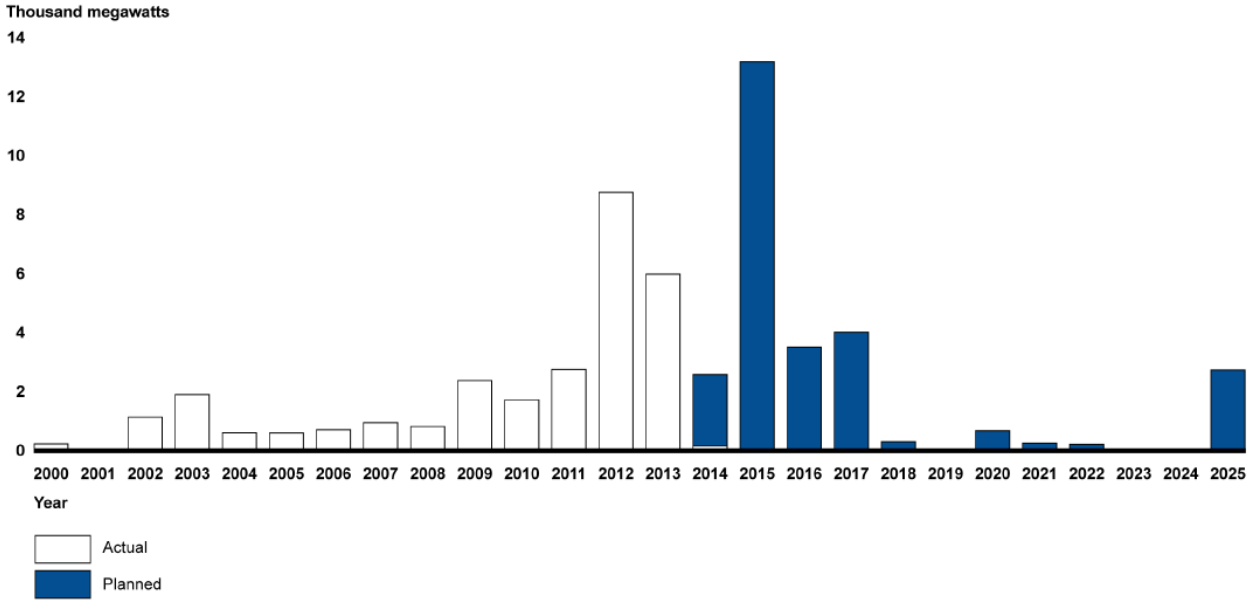
Finally, because one path for implementing regional compliance options for the Clean Power Plan is through cap-and-trade style markets, the chapter closes with an update on current carbon prices in the U.S. from existing cap-and-trade markets and other sources.

A. Updates on Four EPA Regulations Affecting Coal-Fired Generation

For several years, the electric sector has been planning for generation retirements caused by a series of EPA regulations. Now these retirements are beginning to occur, as compliance deadlines approach in 2015 and 2016. An August 2014 report from the GAO provides a status report on these EPA regulations CSAPR, MATS, Cooling Water Intake Structures regulations 316(b), and CCR.[35] It is an update on a similar 2012 report. A key takeaway from this GAO report is that estimates of coal-fueled generation unit retirements in the near future have increased since they were originally made in 2012. The GAO report now confirms the high end of its previous estimates that 13 percent, or 42,192 MW of capacity, will be retired between 2012 and 2025. According to the GAO report, RTOs identified an additional 7,000 MW of capacity that is at risk of being retired. While not all of these retirements will directly be caused by EPA regulations, the report states that about three-quarters were expected to occur by the end of 2015, which is consistent with the MATS compliance deadline. The expected level of coal-fueled retirements each year is shown in Figure 2.1, which indicates that 2015 is the year with the most expected retirements with almost 14,000. This is about the same as the total amount of retirements as between 2000 and 2011.[36]

[35] *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*, GAO, August 2014.
[36] *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*, GAO, August 2014, 15-17.

Figure 2.1. Actual and Planned Retirements of Coal-Fueled Electricity Generation Units 2000-2025 (Net Summer Generating Capacity, thousand MW)



Source: *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*, GAO, August 2014. GAO analysis of SNL Financial Data.

In addition to the 42,192 MW of units expected to be retired, the GAO report noted an additional 70,000 MW of generation is expected to be retrofitted to meet regulations. This means that about one-third of coal fired capacity will be retired or retrofitted between 2012 and 2025.[37] This is a much higher rate of retrofits and retirements than in the past. For example, over a similar number of years, between 2000 and 2011, the GAO report notes that less than 14,000 MW of coal-fueled units were retired.[38]

According to the PJM State of the Market Report for the third quarter of 2014, just over half of the 42,192 MW of retirements expected by the GAO report are estimated to occur in the PJM region. That PJM report showed that over 25,000 MW of PJM generation retired or was planned to retire beginning in 2012.[39] According to MISO's most recent State of the Market report, it expects approximately 8,100 MW of coal-fired retirements.[40] For SPP, as of a 2012 member survey, 1,089 MW of generation was expected to be retired as a result of EPA regulations.[41]

Even as many units are retiring, the regulations forcing the retirements still face some amount of uncertainty. For example, depending on the outcome of pending litigation on the

[37] According to the GAO report in 2012 there was 309,680 MW of coal-fired capacity. *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*, GAO, August 2014, 5, 15.
[38] *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*, GAO, August 2014, 17.
[39] Monitoring Analytics, LLC, *State of the Market Report for PJM*, November 13, 2014, 400.
[40] Potomac Economics, *2013 State of the Market Report for the MISO Electricity Markets*, June 2014, 16.
[41] SPP ITP20 Survey Results, June 14, 2012, available at http://www.spp.org/publications/20120605%20Policy%Survey.xls.

MATS rule before the U.S. Supreme Court, some plants could be brought out of retirement.[42] As reported in last year's Looking Forward Report, the MATS rule had been upheld in legal challenges, including at the D.C. Circuit Court. However, on November 25, 2014, the Supreme Court agreed to hear challenges to the MATS rule brought by industry groups and a consortium of 21 states. The challenge asks the Supreme Court to consider whether it was reasonable for the EPA to ignore costs when deciding whether to regulate, and only consider costs later, when issuing specific pollution standards.[43] According to legal analysts consulted for an article by Bloomberg BNA[44], it was surprising that the Supreme Court decided to hear the case at all because EPA's approach seemed consistent with Supreme Court precedent. These analysts went on to say that the fact that the Supreme Court decided to hear the case at all could indicate a willingness to require the EPA to consider costs in more circumstances. Oral argument is set for March 25, 2015, and a ruling is likely to occur sometime by the end of the Supreme Court's term in June.[45]

While the MATS rule is still going through legal proceedings, the CSAPR rule appears to have finally emerged from an extended legal limbo. The CSAPR rule is designed to limit sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from upwind states so that downwind states can comply with ozone and/or fine particulate National Ambient Air Quality Standards. The CSAPR rule was finalized in 2011, but has been tied up in court proceedings ever since. Most recently, the Supreme Court upheld EPA's rule on April 29, 2014.[46] On December 3, 2014 EPA published in the Federal Register an interim final rule that was in effect as of that date. At that time, EPA also published limits on SO_2 and NO_x emissions, in tons, for each affected unit.[47] Note that affected units are present in eight of the nine states that SPP is currently in, excluding New Mexico.

The other two regulations covered by the GAO report, the 316(b) Cooling Water Intake Structures regulations and CCR rules, were both finalized in the past year. EPA's Cooling Water Intake Structures regulation require electric generating units to limit fish mortality.[48] This regulation was being finalized shortly after last year's Looking Forward Report. Specific deadlines will be established by permitting authorities, which are generally state agencies.[49] The CCR rule, as discussed in last year's Looking Forward Report, was to be finalized in December 2014. At that time, EPA decided to classify CCR as non-hazardous waste, rather than hazardous

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[42] Ambrosio, "Supreme Court Agrees to Hear Challenges To EPA's Mercury Standards for Power Plants," *Bloomberg BNA*, November 26, 2014.
[43] Denniston, "Court to rule on disability rights, mercury pollution," *SCOTUSblog*, November 25, 2014, available at http://www.scotusblog.com/2014/11/court-to-rule-on-disabiity-rights-mercury-pollution/.
[44] Ambrosio, "Supreme Court Agrees to Hear Challenges To EPA's Mercury Standards for Power Plants," *Bloomberg BNA*, November 26, 2014.
[45] "National Mining Association v. Environmental Protection Agency," *SCOTUSblog*, accessed March 6, 2015, available at http://www.scotusblog.com/case-files/cases/national-mining-association-v-environmental-protection-agency/.
[46] For a summary of the legal proceedings prior to this ruling, see Craig R. Roach, Ph.D., Vincent Musco, Andrew Gisselquist, Sam Choi, *Southwest Power Pool Annual Looking Forward Report: Strategic Issues Facing the Electricity Business*, April 22, 2014 (2014 Looking Forward Report), 34.
[47] EPA, "Cross-State Air Pollution Rule: Regulatory Actions," March 6, 2015, available at http://www.epa.gov/crossstaterule/actions.html.
[48] 2014 Looking Forward Report, 37.
[49] *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*, GAO, August 2014, 6.

waste. Industry welcomed this decision, as it reduced direct compliance costs and allowed companies to continue to sell CCR as an input to products such as cement, concrete and wallboard.[50] EPA's original estimate of the effect on electricity rates of CCRs being classified as a non-hazardous pollutant was just 0.2 percent.[51]

B. Status of EPA's Regulations on Carbon Emissions from Power Plants

EPA's proposed regulations on carbon emissions cover both new and existing power plants. Regulations on *new* plants were initially proposed on September 20, 2013 and discussed in last year's Looking Forward Report. In their current form, those regulations require coal plants and natural gas plants that are 100 MW or larger to limit carbon emissions. Coal plants would be limited to 1,100 lbs CO_2/MWh (or a 7-year average emission rate of 1,000 – 1,050 lbs CO_2/MWh) while natural gas plants roughly 100 MW and larger would be limited to 1,000 lbs CO_2/MWh and smaller natural gas plants would be limited to 1,100 lbs CO_2/MWh. The impact – and it is a major impact – is that new or modified coal plants would be required to install carbon capture and sequestration technology to meet these proposed regulations.[52]

EPA's proposed Clean Power Plan will limit emissions from *existing* power plants. These regulations, as a whole, are designed to achieve a 30 percent reduction in CO_2 emissions from the power sector by 2030 as compared to 2005. To calculate the proposed target for each state, EPA began with that state's 2012 average rate of emissions per MWh for covered fossil-fuel units. EPA then applied four "building blocks:"[53]

1. Improve coal units' heat rates by 6 percent.
2. Use lower emitting power sources more by dispatching existing and under-construction natural gas combined cycle units to up to a 70 percent capacity factor.
3. Use more zero- and low-emitting power sources, consistent with maintaining nuclear generation and the average renewable portfolio standard in that state's region.
4. Using electricity more efficiently, by increasing energy efficiency to as much as 1.5 percent annually, and 10.7 percent in total by 2030.

However, these four building blocks are simply how EPA calculated the targets. States are able to develop compliance plans of their choosing to meet these targets, they are not required to use these same methods of reducing emissions. In fact, EPA's Clean Power Plan proposal envisions methods to allow states to use cap-and-trade programs, or another method of pricing emissions, at least implicitly. Specifically, the Clean Power Plan includes a method for states to convert between an average carbon emissions rate per MWh and a calculation of "mass," or total quantity, of allowed carbon emissions. This is useful because it is more practical

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[50] See, for example, National Rural Electric Cooperatives Association "Electric Cooperatives Welcome Non-Hazardous Designation for Coal Combustion Residuals," December 19, 2014, available at www.nreca.coop/electric-cooperatives-appreciate-non-hazardous-designation-for-coal-combustion-residuals/.

[51] Craig R. Roach, Ph.D., Vincent Musco, Sam Choi, Andrew Gisselquist, *2013 Southwest Power Pool Annual Looking Forward Report*, April 23, 2013 (2013 Looking Forward Report), 27.

[52] 2013 Looking Forward Report, 30 and Center for Climate and Energy Solutions, "EPA Regulation of Greenhouse Gas Emissions from New Power Plants," March 6, 2015, http://www.c2es.org/federal/executive/epa/ghg-standards-for-new-power-plants.

[53] *Goal Computation Technical Support Document*, U.S. Environmental Protection Agency, June 2014.

to create cap-and-trade programs to control the mass of emissions than the rate of emissions. Systems that reduce emissions by pricing carbon are generally recognized to be more efficient than a command-and-control approach that requires power plants to take specific types of actions to reduce emissions.

EPA's proposal also included an alternative, and less stringent, set of emission rate targets that it requested comment on. These alternative targets represent emissions performance that EPA believes is achievable by 2025 instead of 2030. These alternatives were for a coal heat rate improvement at 4 percent instead of 6 percent, a capacity factor for natural gas combined cycle units of 65 percent instead of 70 percent, and energy efficiency improvements of 1 percent as opposed to 1.5 percent.[54]

On October 28, 2014 EPA issued a notice of data availability to allow for additional comment on specific aspects of the Clean Power Plan. Aspects that EPA brought up included (a) giving states more flexibility to meet emissions reductions, including phasing in the assumed contribution of higher levels of natural gas dispatch; (b) whether assumptions about the availability of natural gas combined cycle generation are too stringent or too weak for different states; (c) details about how renewable energy potential is calculated within a region; (d) how renewable energy is assumed to contribute to lowering the average emissions rate; and (e) whether it is appropriate to use 2012 as the single base year from which to calculate emission rate reductions, as opposed to another year or combination of years.[55]

EPA's current plan for finalizing carbon regulations is to issue final rules this summer on new, modified, and reconstructed power plants as well as final rules on the Clean Power Plan affecting existing sources. In the summer of 2016, states will submit complete compliance plans or initial plans with requests for 1- or 2-year extension. For states that do not submit plans, EPA will issue a final federal plan for meeting Clean Power Plan. The proposed beginning of the Clean Power Plan compliance period is summer of 2020.

Like every EPA regulation, there are risks to these carbon regulations going forward as planned by EPA. Some risks are political, including efforts to encourage states to not comply with these regulations. For example, Senate Majority Leader Mitch McConnell wrote an op-ed on March 3, 2015 that encouraged states to refuse to go along with these regulations.[56] This approach is also represented in white papers such as one released by the Federalist Society in November 2014 titled *EPA's Section 111(d) Carbon Rule: What if States Just Said No?*[57]

C. Impacts of EPA's Clean Power Plan

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[54] EPA, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," EPA Proposed Rule, June 2, 2014, 201-205, 363-369.

[55] "Clean Power Plan: Notice of Data Availability Related to the Proposed Clean Power Plan," EPA Fact Sheet, October 28, 2014, and Lynch, "Summary: Clean Power Plan – Notice of Data Availability," Georgetown Climate Center, October 30, 2014.

[56] Cappiello, "Top Senate Republican tells states to not draft plans to cut carbon dioxide from power plants," Associated Press, March 4, 2015, available at http://www.usnews.com/news/politics/articles/2015/03/04/top-senate-republican-tells-states-ignore-epa-carbon-rules.

[57] Glaser et al., *EPA's Section 111(d) Carbon Rule: What if States Just Said No?*, Federalist Society, November 2014.

There have been several analyses of the potential impact of EPA's Clean Power Plan on carbon emissions from existing power plants, including analyses from NERC and RTOs/ISOs. Common conclusions from these analyses are that compliance may be expensive, and that regional approaches to compliance are less expensive than state-by-state compliance.

NERC released a study titled *Potential Reliability Impacts of EPA's Proposed CPP* on November 5, 2014.[58] This initial reliability review of the proposal noted both the potentially large impact of the Clean Power Plan and some potential challenges and reliability concerns, especially given the constrained timetable for implementation. NERC summarized EPA's own *Regulatory Impact Assessment* of the Clean Power Plan as indicating it would reduce generation capacity "by between 108 and 134 GW by 2020"[59] depending on whether states choose to implement compliance plans regionally or state-by-state. These estimates of likely retirements are roughly 2.5 to 3 times the 42 GW estimates of retirements caused by the set of EPA regulations MATS, CSAPR, 316(b) and CCR discussed earlier in this chapter. NERC went on to say that "The number of estimated retirements identified in the EPA's proposed rule may be conservative if the assumptions prove to be unachievable. Developing suitable replacement generation resources to maintain adequate reserve margin levels may represent a significant reliability challenge, given the constrained time period for implementation."[60]

NERC's main concerns about EPA's plans included:

- "Assumed heat rate improvements for existing generation may be difficult to achieve:"[61]
- "Increased dependence on renewable energy generation will require additional transmission to access areas that have higher-grade wind and solar resources (generally located in remote areas)."[62]
- "Increased natural gas use will require pipeline expansion to maintain a reliable source of fuel, particularly during the peak winter heating season."[63]
- EPA's assumptions about energy efficiency may also be aggressive.

Overall, NERC has reliability concerns about the Clean Power Plan:

> More time for [Clean Power Plan] implementation may be needed to accommodate reliability enhancements: State and regional plans must be approved by the EPA, which is anticipated to require up to one year, leaving as little as six months to two years to implement the approved plan. Areas that experience a large shift in their resource mix are expected to require transmission enhancements to maintain reliability. Constructing the resource additions, as well as the expected transmission enhancements, may represent a significant reliability challenge given the constrained time period for implementation.[64]

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[58] Additional NERC assessments are scheduled to be released in April 2015, December 2015, and potentially December 2016. NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review*, November 2014, 4.
[59] NERC, *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review*, November 2014, 2.
[60] Ibid.
[61] Ibid.
[62] Ibid.
[63] Ibid.
[64] Ibid.

As an opposing viewpoint, The Brattle Group released a report in February 2015 that assessed NERC's initial reliability review. The Brattle report concluded that there is sufficient flexibility in the Clean Power Plan such that reliability is unlikely to be a concern:

> Following a review of the reliability concerns raised and the options for mitigating them, we find that compliance with the [Clean Power Plan] is unlikely to materially affect reliability. The combination of the ongoing transformation of the power sector, the steps already taken by system operators, the large and expanding set of technological and operational tools available and the flexibility under the [Clean Power Plan] are likely sufficient to ensure that compliance will not come at the cost of reliability.[65]

The discrepancy between these analyses was noted during a panel at the NARUC Winter Conference on February 16, 2015. Gerry Cauley, President of NERC, was asked whether this Brattle report led him to question any of NERC's conclusions on the reliability impacts of the Clean Power Plan. He declined to get into specifics, but essentially said no. He stated that the Brattle report repeats assertions made by EPA in support of its draft regulation, like the potential for coal plant efficiency gains, which NERC believe are not true.

Other analyses have been issued by RTOs. As the Board is aware, SPP's own analysis of the potential reliability impacts of the Clean Power Plan noted that "EPA projections represent approximately a 200% increase in retired generating capacity compared to SPP's current expectations."[66] The implications of EPA's anticipated retirements indicate that significant capacity will need to be constructed in the SPP region to meet SPP's reserve margin.

> In evaluating the impacts of the projected [electric generating unit] retirements on SPP's reserve margin, SPP utilized current load forecasts, currently planned generator retirements and additions, as well as the retirements projected by the EPA. The Assessment showed that by 2020, SPP's reserve margin would fall to 4.7%, which is 8.9% below our minimum reserve margin requirement. Out of SPP's fourteen load-serving members impacted by the EPA's projected retirements, nine would be deficient in 2020. Furthermore, SPP found that its anticipated reserve margin would fall to -4.0% in 2024, increasing the number of deficient load serving entities to ten. These anticipated reserve margins represent a generation capacity deficiency of approximately 4.6 GW in 2020 and 10.1 GW in 2024.[67]

SPP noted that the current timeline to implement EPA's proposed Clean Power Plan may not leave enough time for states to develop and approve plans, for the necessary coordination beyond typical regional planning efforts, broader system assessments of the bulk power system and natural gas pipeline and storage systems, and construction and mitigation measures to accommodate retrofits and retirements.[68]

MISO analysis of the proposed Clean Power Plan found that regional compliance options could save approximately $3 billion annually, as compared to compliance plans that are consistent with EPA's "building blocks" approach. This is not surprising, as MISO calculated

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[65] Weiss, et al., *EPA's Clean Power Plan and Reliability: Assessing NERC's Initial Reliability Review*, The Brattle Group, February 2015, iv.
[66] *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan*, SPP, October 8, 2014, 2.
[67] Ibid., 5-6.
[68] Ibid., 6-7.

that the cost per ton of CO_2 reduced for some of EPA's building blocks was quite high. For example, meeting EPA's building block 3, which is largely about fulfilling state renewable energy targets, could cost $237/ton CO_2 emissions reductions. This is MISO's estimate of the cost of adding enough wind to meet the incremental regional non-hydro renewable energy target. A regional approach, however, required a $38/ton CO_2 price.[69]

PJM modeled several scenarios for complying with the Clean Power Plan. PJM came to the same conclusion that MISO did, in that regional approaches were seen to be less expensive than state-by-state approaches. In particular, state-by-state compliance was modeled as being nearly 30 percent more expensive in 2020 than a regional approach – nearly $45 billion versus $35 billion. Also, as opposed to an estimated 8,000 MW of generation at risk of being retired by 2020 if compliance is done on a regional basis, almost 11,000 MW of additional generation is estimated to be at risk of retirement by 2020 if compliance was done state-by-state.[70] PJM's analysis also argued that, depending on the exact scenario modeled, the resulting CO_2 price in 2020 to limit carbon emissions appropriately ranges from at or near zero to about $40/ton. A scenario consistent with EPA's assumptions for implementing the Clean Power Plan would produce very modest carbon prices. A scenario that had lower renewable energy and energy efficiency, in line with trend growth in PJM renewable energy and energy efficiency, would imply carbon prices that are higher, but still near the lower end of this range.[71]

D. Existing Carbon Pricing in the U.S.

As suggested by the RTO analyses of the Clean Power Plan, regional compliance is likely to be less expensive than state-by-state compliance. A regional approach may be accomplished via regional cap-and-trade markets that will price greenhouse gas emissions. As noted above, MISO indicated that a regional approach may require a carbon price of $38/ton. PJM noted that a wide range of potential carbon prices, from near zero to $40/ton, could be consistent with the carbon emissions reductions sought by the EPA depending on factors such as natural gas prices and the pace of renewable energy generation construction.

To give some context to these estimates of the carbon price needed for the MISO and PJM regions to comply with the Clean Power Plan, Figure 2.2 below presents actual prices for carbon allowances in recent auctions held by existing carbon cap-and-trade markets in the U.S. These two carbon markets are the Regional Greenhouse Gas Initiative (RGGI) in the Northeast and Mid-Atlantic, and the California Cap-and-Trade Program. As can be seen, carbon allowance prices in RGGI have recently risen from about $2/ton – which is near the floor price – to nearly $6/ton, which is the level at which additional allowances will be released, to limit further price increases. The carbon allowance price in California's market has held relatively stable at about $12/ton, which is just above the current floor price of $11.34/ton.[72] These existing carbon prices,

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[69] MISO, *GHG Regulation Impact Analysis – Initial Study Results*, September 17, 2014.

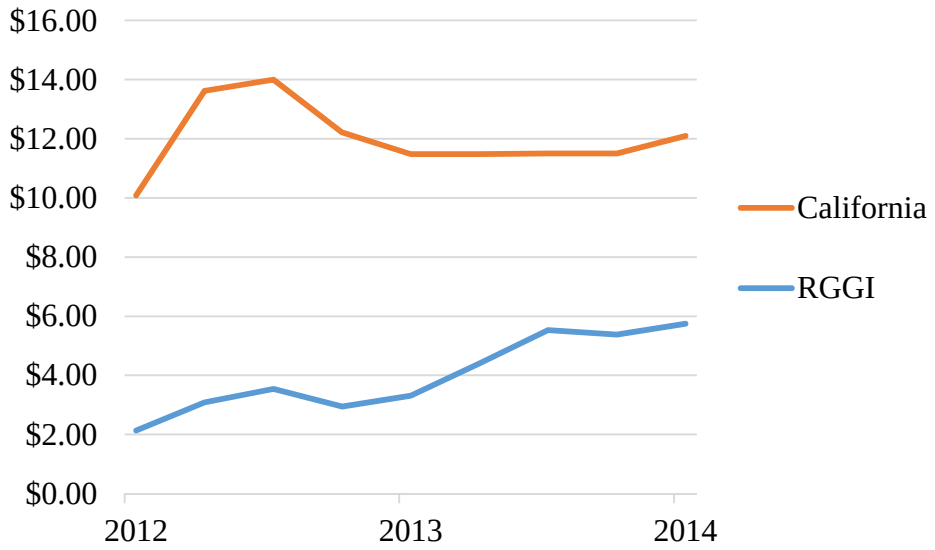
[70] "At risk" means that the unit is a steam turbine that requires revenues equal to at least half of Net Cone to cover its fixed costs. Sotkiewicz and Abdur-Rahman, *EPA's Clean Power Plan Proposal Review of PJM Analyses Preliminary Results*, PJM, November 17, 2014, 56.

[71] Sotkiewicz and Abdur-Rahman, *EPA's Clean Power Plan Proposal Review of PJM Analyses Preliminary Results*, PJM, November 17, 2014, 22-26.

[72] California Cap-and-Trade Program carbon allowance prices are available from the California Environmental Protection Agency Air Resources Board at http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm. For a

which are already accounted for in functioning energy markets, are at the low end of the range of carbon prices that may be needed to comply with the Clean Power Plan in some regions, depending on the stringency of the final regulations.

Figure 2.2. Carbon Allowance Auction Settlement Prices ($/metric ton)



Source: RGGI, California Air Resources Board, author's calculations. RGGI uses short tons and California uses metric tons. Thus, RGGI's prices are converted to metric tons for comparison.

In addition to these existing cap-and-trade markets, a number of electric utilities and other major companies are beginning to use carbon pricing in their corporate planning. These companies factor an implied cost of carbon into their corporate decision-making to limit corporate carbon emissions or to prepare for an external cost to emitting carbon.

According to a September 2014 report from the Carbon Disclosure Project, at least 14 companies in North America, presented below in alphabetical order, disclose an explicit carbon price ($U.S./ton):[73] these prices range from $6/ton to $80/ton. The conclusion is that the internal planning processes of at least some firms may already be consistent with a world in which carbon regulations are placed on the electricity sectors, and possibly other sectors as well.

- Ameren Corporation: $30
- Cenovus Energy Inc.: $16-65
- ConocoPillips: $8-46

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description of the floor price for carbon allowances in California, see this description from the Environmental Defense Fund, at http://www.edf.org/climate/california-cap-and-trade-updates. Allowances prices from the Regional Greenhouse Gas Initiative are available at http://rggi.org/market/co2_auctions/results. For a description of the current floor price and provisions to limit price increases above a certain level, see the Auction Notice for Upcoming RGGI Auctions, available at http://rggi.org/market/co2_auctions.

[73] The Carbon Disclosure Project notes that they "identify a company as using an internal price on carbon if it specifically disclosed using an internal price or if it disclosed internalizing a market price in its business operations, risk management and/or investment decisions." However, it is unclear whether these prices are dollars per ton of carbon or CO_2. It is also unclear whether tons are measured as "short tons" or "metric tons." *Global corporate use of carbon pricing: Disclosures to Investors*, Carbon Disclosure Project, September 2014, 3, 18-20.

- Encana Corporation: $10-80
- Exxon Mobil Corporation: $60-80
- Google: $14
- Mars: $20-30
- Microsoft Corporation: $6-7
- TD Bank Group: $10
- Teck Resources Limited: $30-60
- TransAlta Corporation: $15-23
- Walt Disney Company: $10-20
- Xcel Energy Inc: $20

E. Conclusion

Amid all that EPA is doing to reshape the electricity sector, there are several conclusions that the Board can draw.

1. Current estimates of the impact of EPA regulations that are currently being implemented, which include MATS, CSAPR, 316(b) and CCR, is that they are hitting coal-fired generation hardest. As reported by the GAO, these regulations are estimated to cause fully one-third of coal-fired to be retired or retrofitted.

2. EPA's proposed regulations on carbon emissions from *new* generation prevent any new conventional coal generation from being built. Coal generation will not be allowed under these proposed regulations without being constructed with carbon capture and sequestration technology.

3. EPA's proposed regulations on carbon emissions from *existing* generation, called the Clean Power Plan, could impact all coal generation, as well as large natural gas fired generation.

4. The reliability impacts of EPA's Clean Power Plan are estimated to be significant, but can be reduced through regional compliance approaches.

5. As with all environmental regulations, it is important to remember that EPA's carbon regulations have only been proposed thus far, and may change substantially before being finalized. Once finalized, these regulations will face inevitable court challenges.

III. The Shale Gas Revolution (An Update)

The last several Looking Forward Reports have each discussed extensively the ongoing shale gas revolution brought about by hydraulic fracturing and horizontal drilling technologies. These reports have discussed natural gas prices, estimates of the amount of shale gas that is ultimately recoverable, and possible changes in demand for natural gas, including LNG exports. They have also discussed potential environmental regulations of shale gas that could limit future extraction.

The availability and price of natural gas continues to be an important issue for the Board, as indicated by the 48 percent of the time in 2013 that natural gas is on the margin in SPP, and thereby setting the SPP's spot energy price.[74] Given that, the chapter revisits the state of the natural gas business in the U.S., finding that the shale gas revolution is alive and well. Evidence of this includes strong levels of production of shale gas and natural gas in general, low prices, and increasing levels of natural gas-fired power generation.

Though current estimates are that the shale gas revolution will continue, there is debate about the extent to which it will continue and for how long. The future of the shale gas

[74] SPP 2013 State of the Market Report, 28.

revolution relies, to a large extent, on the shale resources in the ground. The chapter describes mainstream estimates of shale gas resources, as represented by EIA projections, as well as more skeptical estimates which reveal the complex debate over recoverable shale gas reserves. The chapter then turns to the need for additional natural gas pipeline development to ensure that natural gas can be delivered as sources of production and demand grow and shift. A recent report from the Department of Energy concludes that pipeline development over the next 15 years is likely to be less than was needed over the past 15 years largely because areas of production and consumption are now closer. Next, the chapter presents several examples of environmental concerns, including earthquakes and water usage and drinking water contamination. Most such environmental concerns are addressed at the state and local levels. Finally, the chapter ends with a short discussion about the expanding potential for LNG exports. It points to recent approvals of several large LNG export terminals to say that LNG exports could be another major source of demand for U.S. natural gas, on the scale of the current electric sector.

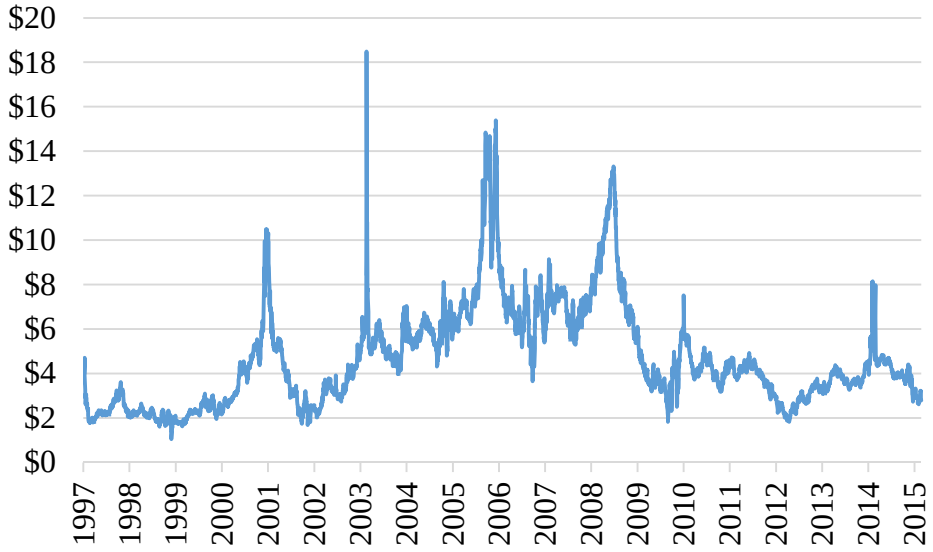
A. The Shale Gas Revolution Continues

As of the writing of this chapter, it is clear that the shale gas revolution is continuing. This means that natural gas production from shale resources continues to be strong and growing, and, as a result, natural gas prices remain low even as the use of natural gas continues to grow. To give some sense of the scale of this revolution, note that EIA data indicates that production of natural gas from shale resources has increased six-fold between 2007 and 2013, and has grown from 8 percent of all natural gas withdrawals in the U.S. in 2007 to 40 percent in 2013. At the same time, production from other sources has declined by 20 percent, suggesting that shale gas is replacing conventional production of natural gas. The total result is an overall increase of 22 percent in natural gas production from 2007 to 2013.[75]

This boom in natural gas production has kept prices relatively low. Figure 3.1 below shows the Henry Hub daily spot price, as given by EIA, 1997 through early 2015. Though current Henry Hub spot prices – which have averaged about $3/MMBtu so far in 2015 – are not as low as in 2012 when prices dipped as low as $1.82/MMBtu on April 20, current prices are much lower than they were in 2008, before the shale gas revolution. In 2008, prices spiked as high as $13.31/MMBtu, on July 2.[76]

[75] EIA, *Natural Gas Gross Withdrawals and Production*, release date February 27, 2015.
[76] EIA, *Henry Hub Natural Gas Spot Price*, release date March 11, 2015.

Figure 3.1. Henry Hub Natural Gas Spot Price ($/MMBtu)

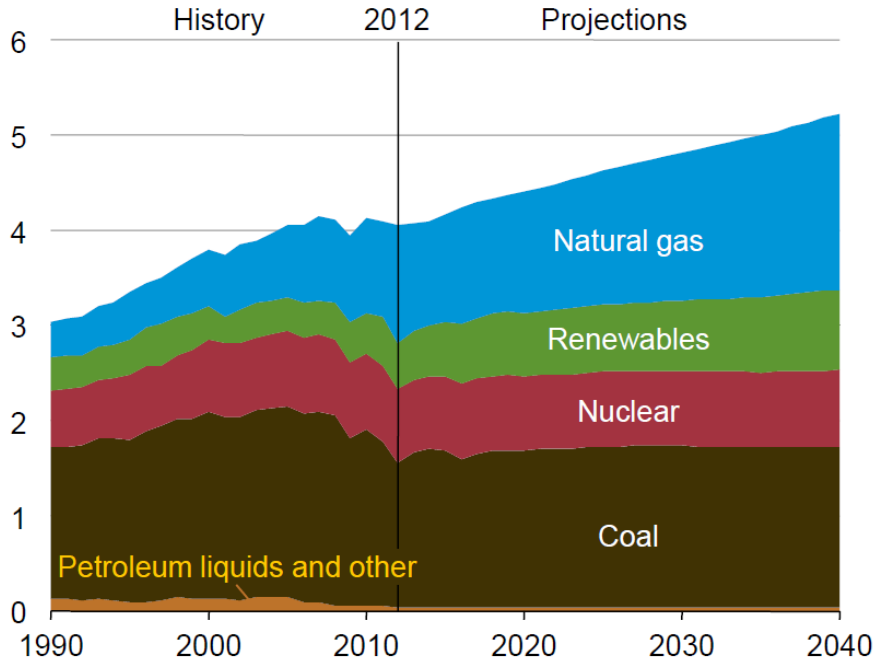


Source: EIA, daily nominal spot price

These low prices have been one of the drivers of the increased use of natural gas in the electric sector (the other main driver being increasingly strict environmental regulations on coal, as discussed in chapter 2). According to EIA, between 2002 and 2012 natural gas-fired power generation increased 77 percent, growing as a share of total electricity generation in the U.S. from 18 percent to 30 percent.[77] This historical growth is shown on the left side of Figure 3.2 below, which is a graph from EIA's 2014 Annual Energy Outlook of the share of electricity generated from different fuels. Further, the right side of that graph shows that EIA expects this growth in the share of natural gas-fired generation to continue, though at a reduced pace, with natural gas making up 35 percent of total generation in 2040.[78]

[77] EIA, *Electric Power Annual*, Table 3.1.A, release date December 12, 2013.
[78] 2014 EIA Annual Energy Outlook, Table A8.

Figure 3.2. Electricity Generation by Fuel in EIA's 2014 Annual Energy Outlook Reference Case (billion MWh)

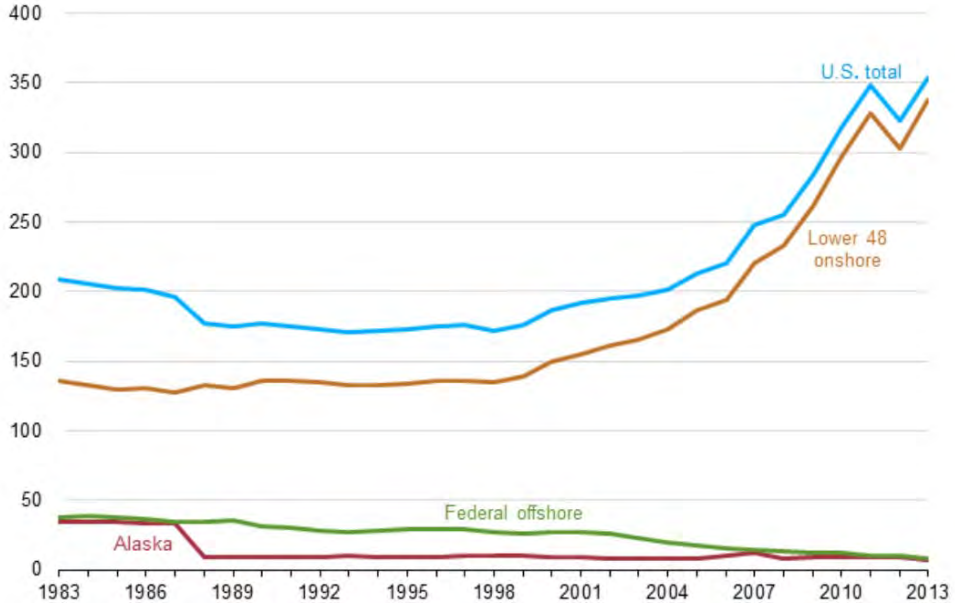


Source: EIA Annual Energy Outlook 2014, page MT-16

Underlying all of this growth in shale gas and natural gas, quite literally, are the shale gas reserves. Through improvements in technology and increased exploration, total natural gas reserves have grown sharply in the last decade. EIA's estimate of the total U.S. natural gas proved reserves is shown in Figure 3.3. From the end of 2003 to the end of 2013, these reserves have increased by 80 percent. [79]

[79] EIA, *U.S. Crude Oil and Natural Gas Proved Reserves*, Table 9, release date December 4, 2014.

Figure 3.3. U.S. Total Natural Gas Proved Reserves (trillion cubic feet)



Source: EIA, *U.S. Crude Oil and Natural Gas Proved Reserves*

The size of that increase in proved reserves (156,849 billion cubic feet)[80] is almost identical to the size of EIA's estimated shale gas reserves (159,115 billion cubic feet).[81] At the end of 2013, 45 percent of EIA's estimate of total proved reserves was composed of shale gas reserves.[82]

B. Natural Gas Price and Supply Projections

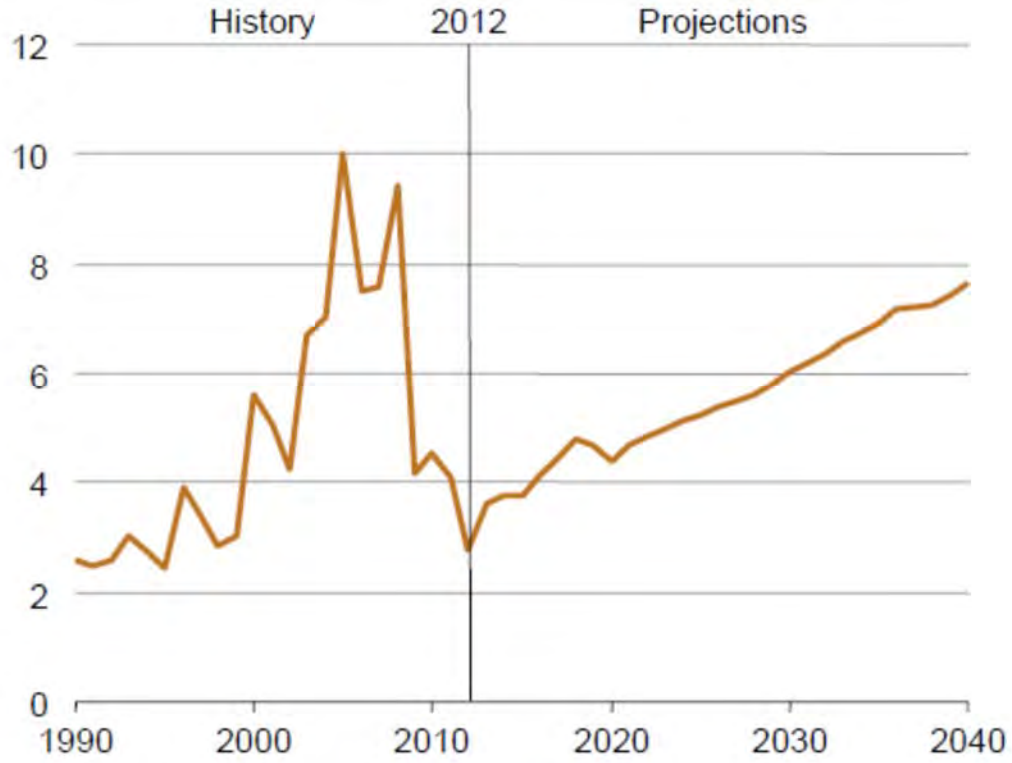
Traditionally, natural gas has been a relatively volatile resource sector, as shown by Henry Hub spot prices in Figure 3.1 above. This volatility is one reason why we have stated in past Looking Forward Reports that the Board should maintain a healthy skepticism when evaluating price forecasts and projections, which typically do not show such volatility. This is either because they discount how volatile the future is likely to be, or more reasonably, are simply unable to predict it. The result is that projections of natural gas production and prices tend to appear much more stable than the future is likely to be. This section of the chapter examines EIA's current projection for natural gas, as an example of mainstream opinion. It then discusses uncertainty around estimates of natural gas reserves.

A current mainstream scenario for future natural gas prices, as represented by EIA's 2014 Annual Energy Outlook, is for steady increases. EIA says that in its Annual Energy Outlook 2014 Reference scenario, natural gas reserves are "abundant" but production costs will increase over time as "producers move into areas where the recovery of natural gas is more difficult and expensive."[83] Figure 3.1 below shows the increase in natural gas price projected by EIA. Prices,

[80] EIA, *U.S. Crude Oil and Natural Gas Proved Reserves*, Table 9, released December 4, 2014.
[81] Ibid., Table 13.
[82] Ibid., Table 8.
[83] 2014 EIA Annual Energy Outlook, MT-21.

in real terms, are assumed to increase from $3.74/MMBtu in 2015 to $7.65/MMBtu in 2040, or 2.9 percent annually.

Figure 3.4. Annual Average Henry Hub Spot Natural Gas Prices in EIA's 2014 Annual Energy Outlook Reference Case ($2012 per MMBtu)



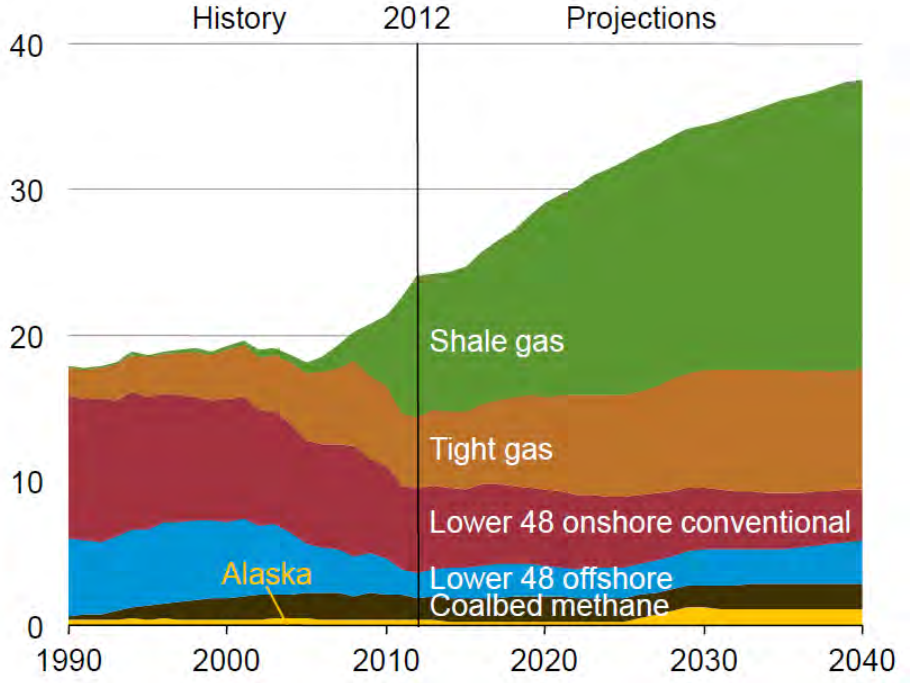
Source: EIA Annual Energy Outlook 2014, page MT-21

A major driver of long-term price expectations for natural gas is the supply picture for shale gas. Although the shale gas revolution is well established in today's natural gas markets, there is little long-term data on production from shale gas fields and wells, so there remains significant uncertainty around estimates of future shale gas production. This uncertainty is reflected in the ongoing debate about natural gas reserves.

To begin to understand this debate, consider EIA's current estimates of natural gas reserves. EIA projects that between 2012 and 2040 there will be a 56 percent increase in total U.S. dry gas production.[84] Shale gas production, which is shown in Figure 3.5 as the top slice of production, is assumed to drive the majority of this growth, increasing from 40 percent of all production in 2012 to 53 percent in 2040.

[84] 2014 EIA Annual Energy Outlook, CP-11.

Figure 3.5. U.S. Natural Gas Production by Source in EIA's 2014 Annual Energy Outlook Reference Case (trillion cubic feet)



Source: EIA Annual Energy Outlook 2014, page MT-23

It is difficult to give some measure of how likely this projection is because long-term production projections tend to be revised significantly, even from one year to the next. For example, as opposed to the 56 percent growth in natural gas production currently projected, EIA's 2013 Annual Energy Outlook had projected an increase between 2011 and 2040 of 44 percent.[85] That is, in the span of one year EIA's current view projections of long-term growth of natural gas production by 2040 increased by 12 percentage points.

On top of this variability in EIA's own estimates of natural gas production, there is uncertainty raised by the existence of other, differing analyses. Some are more optimistic, other less so.[86] Two of the more prominent and technical alternative analyses have both been less optimistic than EIA about estimates of shale gas reserves, which have led them to issue lower projections for natural gas production. The debate about these analyses, at a minimum, highlights the uncertainty faced in natural gas forecasts.

The first of the two alternative estimates of natural gas reserves that are discussed in this chapter is from David Hughes, a geoscientist who had spent 32 years with the Geological Survey of Canada. One of Hughes's credentials with respect to EIA estimates is a December 2013 study in which he referred to EIA's estimates of the recoverable barrels of tight oil in California's

[85] EIA, *Annual Energy Outlook 2013*, April 2013, 101.
[86] For examples of more optimistic analyses, see the figure in Nature, which shows projections from Goldman Sachs, Wood Mackenzie and Navigant as all being more optimistic than EIA. Inman, "Natural gas: The fracking fallacy," *Nature*, December 4, 2014, available at http://www.nature.com/news/natural-gas-the-fracking-fallacy-1.16430.

Monterey shale play as "wildly overoptimistic."[87] Within 6 months the EIA revised their estimates downward by 96 percent.[88]

In 2014, Hughes released a broader report that examines the top seven shale gas plays in the country, which he says account for 88 percent of EIA's 2014 estimated U.S. shale gas production.[89] He concludes that shale gas production will fall off much faster than the EIA projects. From 2014-2040, cumulatively, Hughes's study shows the seven shale plays underperforming their EIA projection by 39 percent. In 2040, Hughes estimates daily production from the seven shale plays to be only approximately one-third that of EIA's estimate.[90]

Hughes offers several critiques of EIA's methodology for estimating future shale gas production. One of them is that EIA does not properly analyze declining production at "sweet spots" – areas that are particularly productive, in boosting current production numbers.[91] For example, in discussing the large Marcellus shale play, Hughes argues that "prices will have to increase to justify drilling in lower quality parts of the play when sweet spots are exhausted."[92] Another critique from Hughes is that EIA assumes that significant additional resources will continue to be found over time and that technology will continue to improve to increase extraction.[93] Hughes says that EIA assumes that between 74 and 110 percent of all *unproved reserves*, which have not been proven to be economically recoverable, plus all *proved reserves* of the seven major plays will be extracted by 2040. Hughes believes that to be "highly speculative."[94]

Hughes also argues that many analysts, EIA included, are too confident that advances in hydraulic fracturing technology will lead to increases in shale gas production. As proof of his concerns over the limits of hydraulic fracturing, Hughes offers evidence that productivity per well in some shale gas plays has stagnated or even declined in recent years.[95]

The other alternative analysis is from the Bureau of Economic Geology at the University of Texas at Austin (BEG), which is studying four major shale plays. BEG's methodology examines wells at a more granular level of analysis than EIA does, each square mile rather than at a county level. This square mile analysis is then aggregated to create production estimates for

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[87] Hughes, *Drilling California: A Reality Check on the Monterey Shale*, post carbon institute, December 2013, 39.
[88] Sahagun, "U.S. officials cut estimate of recoverable Monterey Shale oil by 96%," LA Times, May 20, 2014, available at http://www.latimes.com/business/la-fi-oil-20140521-story.html.
[89] Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts For a Lasting Tight Oil & Shale Gas Boom*, post carbon institute, October 2014, 162.
[90] Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts For a Lasting Tight Oil & Shale Gas Boom*, post carbon institute, October 2014, 15.
[91] Ibid., 16.
[92] Ibid., 282.
[93] Ibid., 14, 16.
[94] Ibid., 14.
[95] Hughes measures well productivity as the average amount of natural gas produced in the first year of new wells. See, for example, Hughes's discussion of the well quality in the Barnett play at Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts For a Lasting Tight Oil & Shale Gas Boom*, post carbon institute, October 2014, 177.

each entire shale play.[96] BEG's methodology allows them to model the productivity of wells at different price points, and assumes advances in technology and recovery factors for each well.[97]

So far BEG has completed its analysis on two shale plays. The results, as compared to EIA's analysis, is lower estimated ultimate recovery amounts. In the Barnett shale play, BEG calculated that 45 trillion cubic feet of gas could ultimately be recovered, which is about 16 percent below EIA's estimate of 53.3 trillion cubic feet recovered by 2040.[98] In the Fayetteville play, BEG estimated ultimate recovery amount of 18.2 trillion cubic feet is about 56 percent below EIA's estimate of 41.5 trillion cubic feet recovered by 2040.[99]

A recent EIA Working Paper discussed improving EIA's model performance by using a more granular level of analysis for estimating reserves, like the BEG methodology, as opposed to its current methodology looking at county-level production. The authors of the paper point out that EIA's current method – which assumes that all wells in a county will have similar production levels – may overweight the sweet spots that are drilled first. The effect would be to overestimate the production potential of that county.

> "A county might have a population of wells within a small area of geologic favorability, and the operative model uses those results across a potentially much larger area, when in fact, the geologic favorability is concentrated in a small area and future results in that county are likely to be much poorer. The presence of the geology necessary for production might not even exist in the remainder of the county….
>
> Across large resource plays this issue may be significant in the aggregate because of resource concentrations and increased well productivity in areas with more favorable rock properties within the same formation. Past experience has shown that industry will locate and focus on drilling in sweet spots for the enhanced production performance these areas offer. However, well productivities are described by a distribution of results, with the more productive end of this distribution residing within sweet spot areas. Future development of the same formation will expand beyond sweet spot areas based on industry considerations of economic viability. This changes the portion of the productivity distribution from which new drilling samples, and leads to a different average outcome as drilling results are projected into less productive parts of a given formation."[100]

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[96] Inman, "Natural gas: The fracking fallacy," *Nature*, December 4, 2014, available at http://www.nature.com/news/natural-gas-the-fracking-fallacy-1.16430.

[97] Browning, et al., "Study Develops Decline Analysis, Geologic Parameters for Reserves, Production Forecast," Oil & Gas Journal, August 5, 2013.

[98] Browning, et al., "Barnett Study Determines Full-field Reserves, Production Forecast," Oil & Gas Journal, September 2, 2013 and EIA estimate from Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts For a Lasting Tight Oil & Shale Gas Boom*, post carbon institute, October 2014, 193.

[99] Browning, et al., "Study Develops Fayetteville Shale Reserves, Production Forecast," Oil & Gas Journal, January 6, 2014 and EIA estimate from Hughes, *Drilling Deeper: A Reality Check on U.S. Government Forecasts For a Lasting Tight Oil & Shale Gas Boom*, post carbon institute, October 2014, 234.

[100] Cook and Van Wagener, *Improving Well Productivity Based Modeling with the Incorporation of Geologic Dependencies*, EIA Working Paper Series, October 14, 2014, 3.

Still, EIA's estimates in its 2014 Annual Energy Outlook may prove to be right. This is despite the technical and more granular nature of the alternate analyses and the EIA Working Paper which suggests EIA could improve their methodology to be more like these alternative analyses. For one, these alternate studies could be too conservative – discounting likely increases in technology and the potential for finding new sources of natural gas. In fact, as cited in a Nature article, "Members of the Texas team are still debating the implications of their own study. [Principal Investigator Scott W.] Tinker is relatively sanguine, arguing that the team's estimates are "conservative," so actual production could turn out to be higher."[101] Second, EIA may also turn out to be right if geologic exploration and technical development continue to be more successful than assumed by these alternate analyses. As shown in Figure 3.3 above, natural gas reserves fluctuate over time. Reserves increase with successful geologic exploration and improvements in technology. Reserves decrease as gas is extracted. The only thing that is certain is uncertainty.

C. Natural Gas Pipeline Developments

The shale gas revolution has shifted the geography of natural gas extraction and the directions of natural gas pipeline flows. This raises the question of whether there is sufficient natural gas pipeline capacity to serve the growing demand from the electric power sector. Without sufficient pipeline capacity, the shale gas revolution can seemingly pass entire regions by. Alternatively, ample supply may be ready to serve demand elsewhere, but is locked in due to limited pipeline capacity, as in Pennsylvania and other states in and around the Marcellus and Utica formations, where prices have recently been half as much as at Henry Hub.[102]

Here we examine a February 2015 report from the Department of Energy titled "Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector." This report models how much natural gas pipeline development will be needed over several scenarios. A key finding of the report is that while pipeline capacity expansion is needed, the amount of pipeline capacity expansion needed over the next fifteen years, 38 to 42 billion cubic feet per day between 2015 to 2030, is only about one-third of the historical rate of pipeline capacity expansion, which was 127 billion cubic feet per day between 1998 to 2013.[103]

There are at least two reasons that the amount of pipeline construction needed going forward is projected to be less than the amount of construction in the recent past. One reason is higher utilization of existing pipeline. Average capacity utilization between 1998 and 2013 was 54 percent, and this is projected to increase to 57 percent by 2030 in the report's reference case.[104] Another reason is that flow patterns for natural gas have evolved.[105] Shale gas

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[101] Mason Inman, *Natural Gas: The fracking fallacy*, Nature, December 4, 2014, available at http://www.nature.com/news/natural-gas-the-fracking-fallacy-1.16430.
[102] Gearino, "Regional natural-gas price half of benchmark," *The Columbus Dispatch*, October 16, 2014.
[103] U.S. Department of Energy, *Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector*, February 2015, vi.
[104] Ibid., 22.
[105] Ibid., vi.

development and increased demand for natural gas has brought sources of production and demand closer together.[106]

In addition to the reference case, two other scenarios analyzed the incremental pipeline capacity needs under a national carbon policy.[107] The report found that the additional capacity needs are modest, at four to ten percent of the reference case additions, depending on the specific assumptions used for coal retirements.[108]

As for natural gas pipeline capacity in the SPP region, this report suggests that only a small portion of the additional capacity will be needed in the SPP region. SPP also appears to avoid significant pipeline expansion in case of a national carbon policy. The report states that "regions in which coal-fired generation is replaced with a greater amount of renewable power, such as MRO and SPP, do not demand as much incremental natural gas as other regions."[109]

D. Environmental and Regulatory Issues

Since the 2012 Annual Looking Forward Report, the reports and analysis that we have reviewed on the impacts of hydraulic fracturing on the environment have come to the same general conclusion – "When done properly, horizontal drilling methods used to release shale gas may not carry more risk than traditional vertical oil and gas drilling."[110] However, this certainly does not mean that hydraulic fracturing is riskless, or that some jurisdictions would not prefer to heavily regulate or ban the practice altogether. Thus, as in previous Looking Forward Reports, we continue to examine the concerns about hydraulic fracturing and whether they are leading to regulations and restrictions that could limit shale gas production.

This section discusses selected changes in state and local regulations, the effect of hydraulic fracturing on earthquakes, and water use and contamination. In the last year, there does not appear to have been much movement for federal action to limit hydraulic fracturing, through there have been numerous state and local regulations passed and court cases heard on the issue. Our conclusion remains that these issues bear continued monitoring.

1. State regulations on hydraulic fracturing

States are the primary venue for regulations related to shale gas and hydraulic fracturing. A 2013 report from the think tank Resource for the Future (RFF) studied state regulations and came to several conclusions.[111] First, these regulations are rapidly changing, consistent with the rapid change of pace of the shale gas industry itself and public attitudes towards it. Anecdotal evidence, discussed below, confirms that this rapid change has continued through 2014. Second, RFF concluded that states regulate shale gas and hydraulic fracturing very differently. This is consistent with a regulatory framework that is in flux. Though the RFF report found it difficult

[106] Ibid., 31.
[107] Ibid., 11.
[108] Ibid., 24.
[109] Ibid., 15.
[110] Craig R. Roach, Ph.D., Vincent Musco, Sam Choi, Andrew Gisselquist, Katherine Smith, *Southwest Power Pool Annual Looking Forward Report*, Boston Pacific Company, Inc., April 17, 2012, 17.
[111] Richardson, et al., *The State of State Shale Gas Regulation*, Resources For the Future, June 2013, 87-90.

to identify specific differences between states that could account for the variance in regulations, it did identify that states with more resource development tend to regulate more broadly. This was thought to be due to these states having more of a need to regulate. One of the few other variables that RFF found that could explain some of the variance in regulations across states was the type of drinking water that a state relied on. The RFF report stated that "Evidence suggests that states that rely more on surface water are likely to have more water regulations, and that those that rely more on groundwater are likely to have more stringent groundwater regulations."[112] This suggests ongoing concerns about the impact of hydraulic fracturing on drinking water supplies.

Turning now to examples of new state regulations, perhaps the most high-profile regulation of the past year was from New York, which sits on parts of the large Marcellus and Utica shale gas plays. In December 2014, Governor Cuomo shifted a moratorium on hydraulic fracturing to an outright ban.[113] Because the moratorium had meant that there had been no shale gas production as of yet, this ban will not actually reduce natural gas production.[114] It will however limit natural gas's potential growth. In issuing this ban, New York joined Vermont and several other jurisdictions around the country.[115]

Governor Cuomo's administration based its decision on a determination that there were uncertainties about the risks of potential health and environmental impacts to allow hydraulic fracturing.[116] Coinciding with the ban, the New York State Department of Health issued a report on the potential consequences of hydraulic fracturing. That report says that a number of ongoing studies – some of which are not scheduled to be completed for years – would help remedy the deficit of data, but that any one study alone would not be sufficient.[117] One conclusion to draw is that, absent a Governor with significantly different beliefs, New York is unlikely to allow hydraulic fracturing for many years. The Department of Health report also summarized the wide array of New York's environmental and health outcome concerns in the following list:[118]

- "Air impacts that could affect respiratory health due to increased levels of particulate matter, diesel exhaust, or volatile organic chemicals.
- Climate change impacts due to methane and other volatile organic chemical releases to the atmosphere.
- Drinking water impacts from underground migration of methane and/or fracking chemicals associated with faulty well construction.
- Surface spills potentially resulting in soil and water contamination.

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[112] Ibid., 86.
[113] Erica Orden and Lynn Cook, "New York Moves to Ban Fracking," *The Wall Street Journal*, last modified December 18, 2014.
[114] EIA, *Natural Gas Gross Withdrawals from Shale Gas Wells*, release date February 27, 2015.
[115] Richardson, et al., *The State of State Shale Gas Regulation*, Resources For the Future, June 2013, 74.
[116] Erica Orden and Lynn Cook, "New York Moves to Ban Fracking," *The Wall Street Journal*, last modified December 18, 2014.
[117] New York State Department of Health, *A Public Health Review of High Volume Hydraulic Fracturing for Shale Gas Development*, December 2014, 85-88.
[118] Ibid., 4.

- Surface-water contamination resulting from inadequate wastewater treatment.
- Earthquakes induced during fracturing.
- Community impacts associated with boom-town economic effects such as increased vehicle traffic, road damage, noise, odor complaints, increased demand for housing and medical care, and stress."

In other states where hydraulic fracturing is already happening at any significant scale, the debate that we have seen most frequently in the past year has been between (a) state laws and regulations that generally allow hydraulic fracturing and (b) localities that want to enact more restrictive regulations. Localities have met different results in different states. In Pennsylvania, localities have won court cases allowing them to restrict hydraulic fracturing more than the state does. However, the opposite has occurred in Ohio and Colorado where state law has prevailed.[119]

2. Earthquakes

As discussed in last year's Looking Forward Report, there has been a significant increase in the number of earthquakes where hydraulic fracturing is occurring. Last year's report concluded that these earthquakes appear to be tied to the use of injection wells, which are used in hydraulic fracturing and for many other purposes.[120] In fact, research has tied earthquakes to injection wells for decades, long before hydraulic fracturing became common.[121]

News about earthquakes this past year largely confirmed our previous discussions. Reports continue to be released about the increasing frequency of earthquakes. For example, in May, 2014 the Seismological Society of America released a notice which said that each year from 2010 to 2012, the U.S. Geological Survey registered, on average, 100 earthquakes measuring 3.0 and larger. This was many more than the just 21 such earthquakes, on average, observed per year from 1967 to 2000.[122] Also, a study published in the journal Science linked a swarm of earthquakes, "which accounted for 20% of the seismicity in the central and eastern United States between 2008 and 2013," to Jones City, Oklahoma from injection wells used in hydraulic fracturing.[123]

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[119] For example, see Rothenberg, Gray and Glickstein, "Current Developments Affecting Hydraulic Fracturing Operations," O'Melveny & Meyers LLP, September 2, 2014, http://www.omm.com/current-developments-affecting-hydraulic-fracturing-operations-09-02-2014/. For further information on the Ohio decisions, see Gorovitz Robertson, "Ohio Supreme Court leaves room for traditional zoning as it rejects Munroe Falls' ordinances," Crain's Cleveland Business online, March 6, 2015, http://www.crainscleveland.com/article/20150306/BLOGS05/150309881/ohio-supreme-court-leaves-room-for-traditional-zoning-as-it-rejects.

[120] 2014 Looking Forward Report, 24.

[121] U.S. Geological Survey, *Earthquake Hazard Associated With Deep Well Injection – A Report to the U.S. Environmental Protection Agency*, Survey Bulletin 1951, 1990.

[122] Seismological Society of America, "Wastewater disposal may trigger quakes at a greater distance than previously thought: Man-made quakes need to be included in seismic hazard planning say experts," May 1, 2014.

[123] Branson-Potts, "Study links Oklahoma earthquake swarm with fracking operations," Los Angeles Times, July 3, 2014, available at http://www.latimes.com/science/sciencenow/la-sci-sn-oklahoma-earthquakes-fracking-science-20140703-story.html.

These earthquakes in Oklahoma have led to at least one major state court case. The state Supreme Court agreed to hear the lawsuit of a woman who was injured in an early November, 2011 earthquake in Prague, Oklahoma which registered a magnitude 5.7 and destroyed 13 homes. She is suing two companies that operate injection wells in that area. At the time of writing, no decision had been rendered. However, one of the defendant corporations is concerned that a finding of legal liability for earthquakes could make it cost prohibitive to conduct hydraulic fracturing in the state.[124]

Other states are also facing earthquakes. A sampling of official reactions suggest that the typical response has been to increase monitoring, but not to significantly increase barriers to hydraulic fracturing; this could be termed a "wait and see" approach. Some examples of state action with regards to earthquakes induced by shale gas development include:

- Colorado, in 2011, began asking a state geologist to review permit applications for new or expanded injection wells after a 5.3 magnitude earthquake.[125]
- The Ohio Department of Natural Resources announced in April of 2014 that it would require "New permits… for horizontal drilling within 3 miles of a known fault or area of seismic activity greater than a 2.0 magnitude would require companies to install sensitive seismic monitors. If those monitors detect a seismic event in excess of 1.0 magnitude, activities would pause while the cause is investigated. If the investigation reveals a probable connection to the hydraulic fracturing process, all well completion operations will be suspended."[126]
- In Texas in October 2014, "The three-member Texas Railroad Commission voted unanimously to adopt the rules, which require companies to submit additional information – including historic records of earthquakes in a region – when applying to drill a disposal well. The proposal also clarifies that the commission can slow or halt injections of fracking waste into a problematic well and require companies to disclose the volume and pressure of their injections more frequently."[127]

3. Water Use and Contamination

In previous Looking Forward Reports we have discussed the effect of hydraulic fracturing on water use and contamination.[128] Several studies released in the past year have shed

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[124] Schlanger, "Oklahoma Court to Decide Whether Fracking Companies Are to Blame for Spate of Earthquakes," Newsweek, January 28, 2015, available at http://www.newsweek.com/oklahoma-court-decide-whether-fracking-companies-are-blame-spate-earthquakes-302747.

[125] Efstathiou, "Fracking-Linked Earthquakes Spurring State Regulations," Bloomberg Business, April 20, 2012, available at http://www.bloomberg.com/news/articles/2012-04-20/fracking-linked-earthquakes-spurring-state-regulations.

[126] Ohio Department of Natural Resources, "Ohio Announces Tougher Permit Conditions for Drilling Activities Near Faults and Areas of Seismic Activity," April 11, 2014, available at http://ohiodnr.gov/news/post/ohio-announces-tougher-permit-conditions-for-drilling-activities-near-faults-and-areas-of-seismic-activity.

[127] Malewitz, "Responding to Quakes, Texas Passes Disposal Well Rules," The Texas Tribune, October 28, 2014, available at http://www.texastribune.org/2014/10/28/responding-quakes-texas-passes-disposal-well-rules/.

[128] A major upcoming report that we highlighted in both the 2013 and 2014 Looking Forward Reports was EPA's *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. A draft of this study was to

light on water usage and causes of water contamination related to hydraulic fracturing. These studies imply that the risks to water from hydraulic fracturing are not much greater than from conventional oil and gas drilling.

One study from the University of Texas Austin indicates that the total amount of water used in hydraulic fracturing for oil production is consistent with the low end of the range of water used in conventional oil production techniques. That is, to the extent water usage has increased as a result of hydraulic fracturing, it appears to be due to an increase in resource extraction, not because hydraulic fracturing uses more water than other techniques.[129] Of course, this does not mean the increased water usage as a result of additional hydraulic fracturing is not a concern. As we discussed in the 2013 Looking Forward Report, water acquisition is an important concern, even if it is highly localized. As a result, more and more drillers are using wastewater or brackish water in their operations.[130]

In addition to the absolute amount of water being used, water contamination continues to be a concern, as discussed above in reference to the RFF report and some of the concerns cited in the New York ban on hydraulic fracturing. However, two recent studies on this issue suggest that water contamination from hydraulic fracturing may be limited and, to the extent it does occur, linked not necessarily to the practice itself, but to faulty wells. A Department of Energy effort independently monitored the hydraulic fracturing process and for 18 months afterwards, at a site in southwestern Pennsylvania. Though there were technical issues that limited the extent of the monitoring, the team found no evidence that the hydraulic fracturing fluid injected far below drinking water migrated upward to contaminate that drinking water.[131] A separate effort, published in the Proceedings of the National Academy of Sciences, studied drilling sites in Pennsylvania and Texas and found that faulty well construction, not hydraulic fracturing itself, were the cause of water contamination.[132] These studies suggest that – at least in the geologic formations studied – hydraulic fracturing may not cause any more environmental concern than other forms of resource extraction such as conventional oil and gas production. To the extent regulations are imposed on hydraulic fracturing, research results like these suggest that the regulations will be on how hydraulic fracturing is done and on the technical aspects of the wells used, as opposed to limiting the practice itself.

E. Liquefied Natural Gas Exports

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have been released in 2014, but it has been delayed, perhaps, as some analysts have said, because EPA has found it harder than expected to get access to data from industry. The draft study is now scheduled to be released this year. See http://insideclimatenews.org/news/02032015/can-fracking-pollute-drinking-water-dont-ask-epa-hydraulic-fracturing-obama-chesapeake-energy.

[129] Scanlon, et al., "Comparison of Water Use for Hydraulic Fracturing for Unconventional Oil and Gas versus Conventional Oil," *Environmental Science & Technology*, (September 18, 2014), 12386, 12392.

[130] 2013 Looking Forward Report, 17.

[131] U.S. Department of Energy, Office of Fossil Energy, *An Evaluation of Fracture Growth and Gas/Fluid Migration as Horizontal Marcellus Shale Gas Wells are Hydraulically Fractured in Greene County, Pennsylvania*, September 15, 2014.

[132] Darrah, et al., "Noble gases identify the mechanisms of fugitive gas contamination in drinking-water wells overlying the Marcellus and Barnett Shales," *Proceedings of the National Academy of Sciences of the United States of America*, vol. 111 no. 39, published online September 15, 2014. See also Begos, "Landmark fracking study finds no water pollution," *Associated Press*, September 16, 2014.

The U.S. is currently a net importer of natural gas, due largely to Canadian imports and scant exports. However, the EIA projects this to change and that the U.S. will become a net exporter of natural gas in 2018, driven by LNG export terminals, exports to Mexico, and declining imports from Canada.[133]

LNG exports have the potential to be another significant source of demand, which would put upward pressure on natural gas prices. Though there remains significant uncertainty about the future scale of U.S. LNG exports, information exists about currently approved and proposed applications for LNG export terminals. There have been five export terminals approved by FERC thus far, totaling 9.22 billion cubic feet of export capacity per day.[134] This is 41 percent as much natural gas as was used by the electricity sector in 2013 – 22.3 billion cubic feet per day.[135] However, in addition to these five approved export terminals, another 14 export terminals have been proposed to FERC.[136] If all currently approved and proposed LNG export terminals are approved, constructed, and operated at their peak capacity, total LNG exports would be 24.6 billion cubic feet per day. This is slightly more than the total amount of natural gas used by the electricity sector in 2013.[137]

F. Conclusion

Natural gas, and shale gas in particular, continues to be a driving force in the electricity sector, as demonstrated by continued low natural gas prices, increasing production, and increasing use for electricity generation. Whether the shale gas revolution continues into coming decades is uncertain. There exist both below ground and above ground risks to continuing the shale gas revolution. Below ground, estimates by EIA and others of a robust future of shale gas generation depends in part on whether current estimates of abundant shale gas reserves below ground prove to be accurate. While other recent technical analyses of shale gas reserves have not disproved EIA's projections, these analyses have at least revealed the uncertainty inherent in predicting future natural gas production and prices.

Above ground, the clearest risk is from more restrictive regulations. So far, we have not seen significant moves to restrict hydraulic fracturing at the federal level, but some states and localities have gone so far as to ban it – New York being a prominent example. Concerns continue to exist around the earthquakes that continue to be linked to injection wells used in hydraulic fracturing and other practices. However, in terms of water contamination, the practice of hydraulic fracturing itself has not yet been identified as a major culprit. Research has instead pointed to poor well construction. However, further research is needed. Additionally, concerns still exist over the absolute quantity of water being used in many forms of resource extraction, which can aggravate drought conditions.

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[133] 2014 EIA Annual Energy Outlook, MT-24.
[134] U.S Department of Energy/FERC, "North American LNG Import / Export Terminals: Approved," as of February 5, 2015.
[135] EIA, *U.S. Natural Gas Deliveries to Electric Power Consumers* and author's calculations, assuming 365 days per year.
[136] U.S. Department of Energy/FERC, "North American LNG Export Terminals: Proposed," as of February 5, 2015.
[137] EIA, "U.S. Natural Gas Deliveries to Electric Power Consumers (MMcf)," 2014; Author's calculations.

Finally, even if natural gas supply continues to grow due to shale gas production, natural gas demand is uncertain and may significantly affect prices. LNG exports could significantly increase demand for natural gas, putting pressure on natural gas prices.

IV. Update on the Changing Electric Sector Business Model

A. Introduction

Last year's Looking Forward Report noted increasing interest and discussion of distributed generation and other decentralized technologies. We noted that these technologies have already impacted the operation of the electric power grid and are projected to play a greater role going forward.[138] We looked at concerns about distributed generation becoming an existential threat to the traditional bulk electric system, while noting an Electric Power Research Institute (EPRI) report[139] that suggested that the grid and decentralized technologies are best thought of as complements, not competitors, and that an integrated grid, with both centralized and distributed components, is more likely. EPRI stated, for example, that for average homeowners to separate from the grid completely through a combination of solar and batteries

[138] 2014 Looking Forward Report, 42.
[139] Electric Power Research Institute, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, February 2014 (EPRI Report).

would be hundreds of dollars per month more expensive than remaining on the grid, even with expected cost reductions over the next decade.[140]

We concluded in the 2014 Looking Forward Report that, at this point, "there is no definitive answer to whether and to what extent distributed technologies will represent a head-on competitive threat to the existing utility network model."[141] We noted that distributed generation already exists widely, with capacity equal to one-fifth that of centralized generation, but that most of it is used primarily by customers to provide emergency, backup power when grid power is not available. As noted by the U.S. Department of Energy (DOE), "[w]hile many electric utilities have evaluated the costs and benefits of [distributed generation], only a small fraction of the [distributed generation] units in service are used for the purpose of providing benefits to electric system planning and operations."[142]

This year, we build on and update last year's findings to provide the Board with a view of what is happening in the area of decentralization and the attempts to compete with centralized power. The Board should be aware that there is activity on a number of fronts, including (a) cost reductions and technological advances in decentralized resources, and other drivers of new electric sector business models, (b) innovation by private industry to develop decentralized business models, (c) continued financial pressures on traditional utilities via rising costs and flat demand, and (d) regulatory initiatives to provide decentralized technologies (and businesses) to compete with utility power. We expand on these four points below, including some pertinent examples and evidence of this ongoing activity. As we noted in the 2014 Looking Forward Report, "[i]n the extreme, decentralized technologies could represent a competitive threat to the existing, centralized power grid" leading some to suggest that "the grid could be relegated to backing up distributed resources."[143] While we do not see evidence that such a result is inevitable, the Board should be aware that there is significant activity in the private and public sector that could lead to fundamental changes in the electricity business.

B. Cost Reductions and Technological Advances in Decentralized Resources

There are several drivers opening up space for new electric sector business models to deliver distributed energy solutions. One driver, for example, is that distributed energy solutions offer customers ways to be proactive about their energy production and use that until recently were not possible. But perhaps the biggest drivers are the cost reductions and technological advancements that have been made in decentralized resources.

A commonly cited form of distributed energy technology is solar photovoltaic, sometimes combined with batteries. The growth in solar photovoltaic generation and decline in its costs – as we have discussed in the past[144] – has continued. Figure 4.1, which is taken from a recent report from Lawrence Berkeley National Laboratory, shows the steady decline in the installed price of solar photovoltaics that has occurred since 1998. As shown in the figure, the

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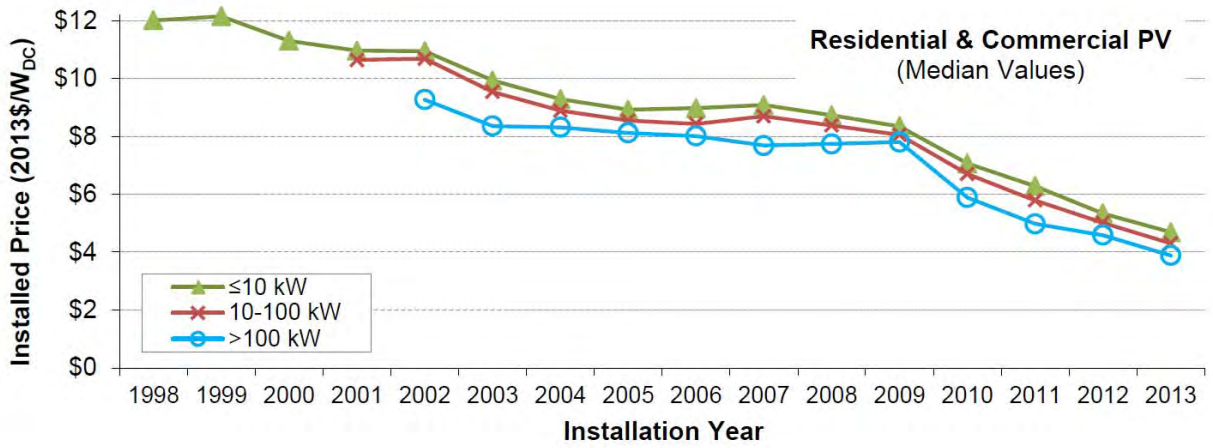
[140] EPRI Report, 23.
[141] 2014 Looking Forward Report, 5.
[142] U.S. Department of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion*, February 2007, iii.
[143] 2014 Looking Forward Report, 5.
[144] 2014 Looking Forward Report, 47.

installed price per watt of solar photovoltaic capacity has fallen especially since 2009, when it dropped from about $8/watt in 2009 to near $4/watt in 2013, a decline of roughly 50 percent.

Figure 4.1. Installed Price of Residential and Commercial Solar Photovoltaics over Time



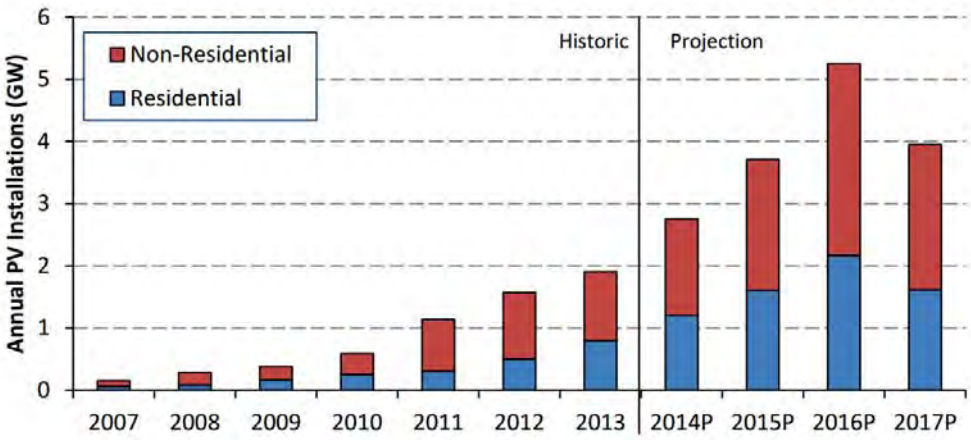
Source: Lawrence Berkeley National Laboratory, Tracking the Sun VII, September 2014, p. 13

Other sources show even lower prices for solar photovoltaics today. A recent report from Lazard, a large financial services firm, assumes that by 2017, the levelized cost of power from residential rooftop solar will be $130/MWh, or $2.20/watt.[145] SolarCity, the largest U.S. solar installer, which is discussed later in this chapter, says that its current installed cost is already down to $2.09/watt.[146] Additionally, as an example of the potential future declines in the cost of solar, SolarCity says that its current expansions of scale will help it to continue to reduce costs. It is targeting an installed cost of just $1.20/watt of solar capacity, a further 42.6 percent decline from current costs.[147] These installed costs suggest that in certain locations, distributed solar generation may become competitive with centralized power generation for energy.

Alongside the decline in price, the adoption of distributed solar resources continues to increase. According to a report from NREL, analysts expect that the strong growth in distributed solar installations in recent years will continue through 2016, when federal tax incentives are scheduled to expire. The report goes on to say that even after the expiration of federal tax incentives, the distributed solar market is expected to continue to remain strong, primarily due to (a) cost reductions, (b) high market prices for distributed solar in the U.S., and (c) lower cost financing vehicles in the solar market using securitized products, like those recently developed by SolarCity, Mosaic, and NRG. Figure 4.2 below shows historical, current, and projected distributed solar installations.

[145] *Lazard's Levelized Cost of Energy Analysis – Version 8.0*, Lazard, September 2014 (Lazard LCOE Report), 6.
[146] "SolarCity Slashes Installation Costs; Citigroup Pledges $100B for Projects," The Energy Collective, March 7, 2015, available at http://theenergycollective.com/lexie-briggs/2199541/news-solarcity-slashes-installation-costs-citigroup-pledges-100b-projects.
[147] Bullis, "Solar City and Tesla Hatch a Plan to Lower the Cost of Solar Power," *MIT Technology Review*, September 19, 2014.

Figure 4.2. U.S. Distributed Solar Photovoltaic Installations



Source: Feldman and Lowder, *Banking on Solar: An Analysis of Banking Opportunities in the U.S. Distributed Photovoltaic Market*, NREL, November 2014, 16.

Though solar is the most prominent source of distributed energy services, it is not the only source that is growing in technical sophistication and declining in cost. For example, hydrogen fuel cells "are electrochemical devices that combine hydrogen and oxygen to produce electricity, water, and heat. Unlike batteries, fuel cells continuously generate electricity as long as a source of fuel is supplied."[148] According to a report by the U.S. DOE, "[f]uel cells do not burn fuel, making the process quiet, pollution free and two to three times more efficient than combustion."[149] Cost reductions in stationary fuel cells appear to be substantial. The DOE Fuel Cell Report noted several examples of fuel cell manufacturers reducing costs per kW of up to 75 percent per kW over roughly the last decade; in one instance, the cost per kW for one fuel cell manufacturer is $2,500/kW.[150]

Batteries are also poised to reduce the demands on the bulk energy system by shifting demand to off-peak periods, and by providing various ancillary services which will allow more intermittent distributed generation to be incorporated. A recent EPRI report estimates that installed battery costs today are $697/kWh of storage capacity.[151] The Lazard report assumes similar capital costs and calculates that, with a $60/MWh cost to charge the battery, the levelized cost of energy would be between $265/MWh and $324/MWh.[152] However, battery technology is expected to see substantial cost reductions going forward. The EPRI report estimates that the costs of batteries for residential customers will decline by almost 40 percent in the next decade, to $422/kWh of storage capacity in 2025.[153] Other analysts are even more optimistic. A recent study from The Brattle Group cited a projection of installed costs of battery systems of

[148] *2013 Fuel Cell Technologies Market Report*, U.S. Department of Energy, Energy Efficiency & Renewable Energy Fuel Cell Technologies Office, November 2014, (DOE Fuel Cell Report) 1.
[149] DOE Fuel Cell Report, 1.
[150] DOE Fuel Cell Report, 45.
[151] *Residential Off-Grid Solar Photovoltaic and Energy Storage Systems in Southern California*, EPRI, September 2014, (EPRI Storage Report), viii.
[152] Lazard LCOE Report, 2.
[153] EPRI Storage Report, viii.

$350/kWh in 2020.[154] In that same report, Brattle also noted forecasts by Morgan Stanley and Tesla Motors that forecasted battery-only costs of $125/kWh to $150/kWh and $110/kWh, respectively, in "the near future."[155]

C. Private Innovation to Develop Decentralized Business Models

We now turn to describe a selection of new business models that are being developed to harness technology advances. These models seek to apply new technology to challenge existing regulatory constructs, the traditional relationship between utilities and customers, and the monopoly of the transmission grid.

1. Distributed Solar

One prominent example of a new business model challenging tradition is distributed solar photovoltaic panels, which as we explained in the previous section, have seen cost decreases in recent years. Distributed solar panels can provide local energy generation and, often incentivized by net metering regulations, sales of excess generation to the grid. When combined with a battery, these systems can provide a measure of resilience against grid outages and, as new markets for distribution systems develop – like the example of New York's "Reforming the Energy Vision" initiative we explain below – other services, including ancillary services, for the grid.

The growth in solar panel installations has challenged utilities in at least two ways. First, according to a recent article in *Electric Light & Power*, solar PV growth has challenged utilities operationally; the intermittency of distributed solar cane lead to "voltage fluctuations…reverse power flow, reduced switching flexibility, lack of visibility of actual circuit loads…increased O&M costs for voltage regulation equipment, and transmission-level aggregation issues."[156] Second, distributed solar has challenged utilities financially, especially through the use of net metering programs, which credit distributed solar customers for power they generate and often pay them the full-bundled retail rate for excess power they sell to the grid. As we noted in last year's Looking Forward Report, some contend that because distributed solar customers are paid the retail rate – which averaged 12.5 cents per kWh – solely for their generation that would otherwise sell for "near or below 3 cents per kWh," "net metering allows the owners of distributed generation to effectively sell their energy at prices between two and six times the market price for energy."[157] Utilities, meanwhile, may be concerned that incentives for investing in distributed solar – like net metering programs – will cause some of their customers to buy less of their product; as the utility must still incur costs to maintain the distribution and transmission

[154] Chang, et al., *The Value of Distributed Electricity Storage in Texas*, The Brattle Group, November 2014 (Brattle Storage Study), 1.
[155] Brattle Storage Study, 1.
[156] Rodger Smith, "How to Tackle the Challenges of Distributed Generation on the Grid," Electric Light & Power, October 8, 2014, available at http://www.elp.com/articles/print/volume-92/issue-5/sections/it-cis-crm/how-to-tackle-the-challenges-of-distributed-generation-on-the-grid.html.
[157] 2014 Looking Forward Report, 51, citing Raskin, "The Regulatory Challenge of Distributed Generation," *Harvard Business Law Review Online*, last modified December 2, 2013, 41.

infrastructure, it may need to pursue rate increases, which could further incentivize utility customers to invest in distributed solar.

One large Arizona utility, Salt River Project, recently responded to this concern by approving a new tariff for residential solar customers. This tariff introduces a demand charge based on a customer's peak energy usage, making their bill more like that of a commercial customer. The effect is about $50 per month extra to the average solar user's bill, making a basic solar energy installation less cost effective.[158] Salt River Project has stated that customers can reduce the size of this demand charge by "reduc[ing] demand during on-peak periods,…installing load controllers, using battery technologies, and by shifting load to off-peak periods."[159]

The largest distributed solar installer in the U.S., SolarCity, has already filed suit against the tariff change.[160] However, at the same time, SolarCity has also been adapting its business model and product offerings to adapt to the reality represented by Salt River Project's tariff change. Since December 2013, SolarCity has been targeting utility demand charges by offering a package of solar panels, batteries, and software that can target and reduce peak energy demand.[161]

SolarCity is also evolving its business model from marketing and installing third-party solar panels and related systems to a more vertically integrated approach that incorporates solar panel and battery manufacturing. In June 2014, SolarCity agreed to purchase solar panel maker Silevo.[162] It is currently planning a large solar panel manufacturing facility that could, with other continued advances, reduce the cost of installed solar systems from $2.09/watt today to $1.20/watt. Alongside that effort, SolarCity is part of the plan announced in September 2014 by its sister company, Tesla Motors, for a battery factory in Nevada that could produce as many lithium-ion batteries as are currently produced worldwide. These batteries could be used both in cars and on the grid. Elon Musk, SolarCity's chairman and CEO of Tesla Motors, said that the battery factory could help lower the cost of batteries by about two-thirds and that in the next five to ten years, every SolarCity installation will include battery backup.[163]

2. Virtual Power Plants

Another emerging challenge to the traditional utility model involves "virtual" power plants, which Navigant Research defines as "a system that relies upon software and a smart grid to remotely and automatically dispatch and optimize distributed energy resources via an

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[158] Randazzo, "SRP board OKs rate hike, new fees for solar customers," *The Arizona Republic*, February 27, 2015.
[159] "Proposed changes for new rooftop solar customers," *Salt River Project website, March 5, 2015,* http://www.srpnet.com/prices/priceprocess/customergenerated.aspx.
[160] "SolarCity Files Lawsuit Against Salt River Project for Antitrust Violations," *greentechmedia*, March 3, 2015.
[161] SolarCity, "SolarCity Introduces Energy Storage for Businesses," December 4, 2013, available at http://www.solarcity.com/newsroom/press/solarcity-introduces-energy-storage-businesses.
[162] SolarCity, "SolarCity to Acquire Silevo," June 17, 2014, available at http://www.solarcity.com/newsroom/press/solarcity-acquire-silevo.
[163] Bullis, "Solar City and Tesla Hatch a Plan to Lower the Cost of Solar Power," *MIT Technology Review*, September 19, 2014.

aggregation and optimization platform linking retail to wholesale markets."[164] In other words, virtual power plants are aggregation of distributed generation, energy storage, and customer load into a system that can be treated, from the utility's perspective, as a single, dispatchable resource. Using smart grid and communications technology, established firms such as Siemens and Ventyx are seeking to commercialize this approach, with Siemens having already created systems in excess of 20 MW.[165] These virtual power plants could be another challenge to the assumption that meeting load growth requires adding centralized generation and associated transmission.

A specific example of the virtual power plant comes from Duke Energy. Duke's pilot project "at a substation in Charlotte, N.C. …. includes a 50-kilowatt solar array, a 500-kilowatt zinc bromide battery and about 100 households equipped with a home energy management system." [166] This pilot project used smartgrid technology and automated systems to arbitrage energy production, storage and demand across volatile renewable energy (solar), batteries, and customer load. In short, this system located on the local distribution grid was able to choose how to manage the battery storage capacity, in conjunction with the distributed energy production and local energy demand, to determine when it was most cost effective to buy and sell power from the grid or to send signals to homeowners' appliances to reduce demand during high load events. Representatives from Duke Energy and their project partner presented on the pilot project, saying normal operations "would result in a net loss of over a dollar, while managing all these resources as a system results in a net income of over four dollars." These representatives described the project in their own words:

> Utilities in general are seeking ways to curtail electricity at peak time, such as the middle of a hot summer day, when they may need to fire up expensive and polluting auxiliary power plants to meet high demand. Rather than bring on new power capacity during peak times, the McAlpine Creek substation draws stored electricity from the battery and level[s] off demand through the residential energy management system. Consumers can volunteer to have their air conditioner thermostat adjusted or other appliances turned off for a short period to reduce energy usage. The information about power reduction--aggregated across the different homes--is communicated back to Duke via a network so the utility can supply electricity to meet adjusted demand.[167]

3. Demand Side

The increasing power and pervasiveness of two-way communications technology is opening the demand side of the grid to new business models. Some companies have deployed demand response in electricity markets by applying advanced analytics on top of data and communications made possible by the smart grid. Companies are now taking the capabilities of demand a step further by aggregating specialized types of load to offer ancillary services. One example is VCharge, which has access to hundreds of home electric heating units. These units

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[164] Asmus, "How Real are Virtual Power Plants?," *Electric Light & Power*, November 18, 2014 (EL&P Virtual Power Plants Article).
[165] EL&P Virtual Power Plants Article.
[166] Ozog and Ratnayake, *Orchestrating Duke's 'Virtual Power Plant,'* Presented at: Association for Energy Services Professionals National Meeting, 2010 (Duke VPP Presentation), 1.
[167] Duke VPP Presentation, 7.

may be large ceramic bricks or water tanks that were originally designed to be heated over the course of about five hours using cheap power – typically overnight – and then release the stored heat into the home for up to twenty-four hours. Now, however, with advances in networking technology and software, these devices can be aggregated and monitored to act like one system. VCharge buys power on behalf of its customers to power the home heating units, seeking to buy when energy is attractively priced. At the same time, VCharge bids into both PJM's and ISO New England's energy and frequency response markets, which provide payments to loads that can change their energy consumption in seconds. Using this model, VCharge promises to save its customers 25 percent on heating costs while still producing a profit. The result is a form of energy storage that costs a little over $15 per kWh, dramatically lower than typical installed grid battery projects. VCharge has launched projects in Pennyslvania, Massachusetts, and Maine. A number of other firms are using similar business models, aggregating resources like water pumps, cold storage units and building heating and cooling systems.[168]

There is one substantial uncertainty related to such demand-side participation in wholesale electricity markets. On May 23, 2014, the U.S. Court of Appeals issued a decision vacating FERC Order No. 745, ruling that demand response is a retail product under state, not federal, jurisdiction.[169] (FERC Order No. 745 mandated that demand response providers be paid the full locational marginal price in wholesale energy markets.) As we explain in chapter 6, that ruling has been stayed and is pending appeal at the U.S. Supreme Court, casting uncertainty on the future of demand response participation in wholesale markets.

D. Financial Pressure on Utilities

1. Pressure from Decentralized Technologies

These emerging challenges to traditional reliance on the bulk energy system have begun to create financial pressure on at least some utilities. As noted above, distributed solar installations have challenged utilities. As noted in a recent McKinsey publication:

> "Depending on the market, new solar installations could now account for up to half of new consumption (in the first ten months of 2013, more than 20 percent of new US installed capacity was solar). By altering the demand side of the equation, solar directly affects the amount of new capital that utilities can deploy at their predetermined return on equity. In effect, though solar will continue to generate a small share of the overall US energy supply, it could well have an outsize effect on the economics of utilities—and therefore on the industry's structure and future.[170]

The potential for distributed generation, and solar in particular, to reduce utility rates of return was also borne out by a recent Lawrence Berkeley National Laboratory study. This study analyzed in detail the impact of distributed solar penetration on the financial returns of a large Southwestern U.S., vertically integrated utility and a utility in the Northeast that only delivers

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[168] St. John, "VCharge Is Turning 'Hot Bricks' Into Grid Batteries," *greentechgrid*, April 2, 2014, available at http://www.greentechmedia.com/articles/read/vcharge-turning-hot-bricks-into-grid-batteries.
[169] United States Court of Appeals, Electric Power Supply Association v. FERC, No. 11-1486, May 23, 2014.
[170] Frankel, Ostrowski, and Pinner, *The disruptive potential of solar power*, McKinsey Quarterly, April 2014.

power and does not own any generation. The conclusion was that the utilities' earnings and return on equity would be materially impacted even at low rates of solar penetration. At a level of penetration of 10 percent, the earnings for the Southwestern and Northeastern utilities would be reduced by 8 and 15 percent, respectively. Because costs do not fall at the same rate as revenues, the average return on equity of these two utilities would fall by 23 basis points (3 percent) and 125 basis points (18 percent), respectively.[171]

In recognition of these potential financial challenges, in May 2014 Barclays downgraded bonds from the electric utility industry due to the threat from distributed solar technology and storage. Barclays pointed to the unique nature of solar plus storage as a potentially cost-competitive substitute for grid power:

> Electric utilities… are seen by many investors as a sturdy and defensive subset of the investment grade universe. Over the next few years, however, we believe that a confluence of declining cost trends in distributed solar photovoltaic (PV) power generation and residential-scale power storage is likely to disrupt the status quo. Based on our analysis, the cost of solar + storage for residential consumers of electricity is already competitive with the price of utility grid power in Hawaii. Of the other major markets, California could follow in 2017, New York and Arizona in 2018, and many other states soon after.
>
> In the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power. We believe that solar + storage could reconfigure the organization and regulation of the electric power business over the coming decade. We see near-term risks to credit from regulators and utilities falling behind the solar + storage adoption curve and long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power.[172]

Barclays was also quoted as saying that investors may be missing the technology-driven shifts that could lead to changes in the existing "regulatory compact" that investors are relying on for stable utility returns.

> Valuations suggest credit investors are depending on the 'regulatory compact,' (whereby the monopoly utility agrees to invest in assets to service customers in return for prices that are set to allow them a reasonable return) to give sufficient protection from industry changes. While the regulator/utility construct has usually resulted in low-risk returns to credit in the past, technological change creates precisely the environment where slower-moving incumbents and their regulators can fall behind the curve, risking credit volatility, or disrupt the regulatory compact, possibly leading to unexpected losses for bondholders. Investors may be also wary of optimism about solar power, given a recent history of losses in that industry. We believe that sector spreads should be wider to compensate for

[171] Satchwell, Mills, and Barbose, *Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A Scoping Study of Two Prototypical U.S. Utilities*, Lawrence Berkeley National Laboratory, September 2014, ix.
[172] Micahel Aneiro, "Barclays Downgrades Electric Utility Bonds, Sees Viable Solar Competition," *Barron's Income Investing*, May 23, 2014 (Barclays Downgrade Article), available at http://blogs.barrons.com/incomeinvesting/2014/05/23/barclays-downgrades-electric-utility-bonds-sees-viable-solar-competition.

the potential risk of regulator missteps and/or a permanent change in the utility business model.

Whether because of biases or analytical complexity, the market (and its constituent prognosticators) has tended to be late in pricing technology-driven shifts, particularly in industries that have had stable operating models (such as telcos and airlines).[173]

However, other financial analysts are not convinced of the threat to utilities. In January of this year, Moody's announced that "despite falling battery costs, consumers [are] unlikely to defect from utilities."[174] Moody's argues that the size of battery systems needed before ratepayers can leave the grid is often understated, as analysts fail to account for the variability in usage. Moody's analysis suggested that the capital cost of batteries would have to fall by approximately 95 percent or more, from $500-600 per kWh today to $10-30 per kWh. Aside from battery costs, Moody's stated that "solar generation is required in a solar-battery combination," and that "the number of households with rooftop solar is very small and the vast majority of them rely on net energy metering economics."[175] Additionally, Moody's argued that leaving the grid would require lifestyle adjustments – such as monitoring battery charge levels – that would be "unacceptable to most people."[176]

2. Slow Electricity Demand Growth

Another emerging financial challenge facing utilities is slow or flat electricity demand growth. Slow demand growth limits utilities' ability to increase revenues and provides fewer kWh over which to spread incremental fixed costs. The 2013 Looking Forward Report discussed slow demand growth in reference to a Deloitte report that suggested that there is a "potential for slow, stagnant, or even declining electricity consumption."[177]

The 2014 EIA Annual Energy Outlook supports the view that demand growth is likely to be modest, at best, going forward. As shown in Figure 4.3 below, U.S. electricity demand growth has decreased sharply since the 1950s. Specifically, EIA's calculated trendline for electricity demand has declined from about 10 percent in the 1950 to about 2 percent in the 1990s, to about 1 percent today. In fact, EIA's projection for demand growth is 0.9 percent annually from 2012 through 2040.

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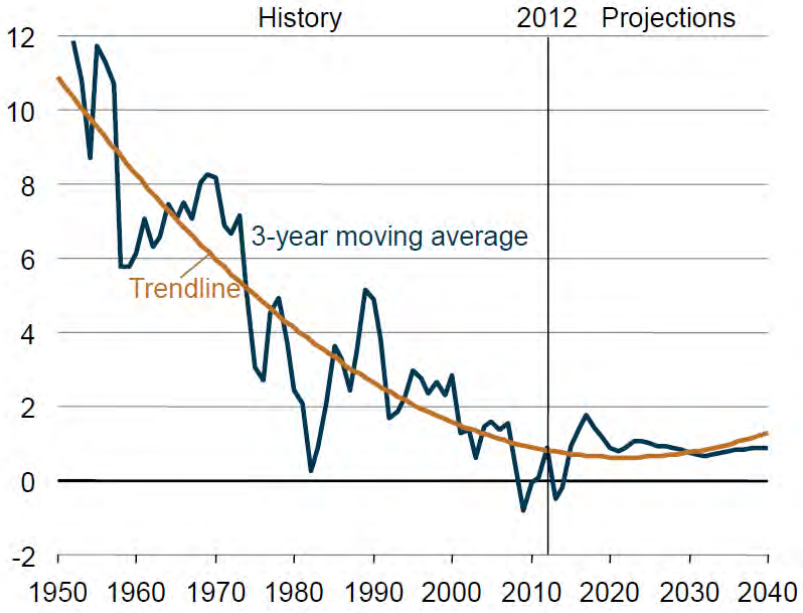
[173] Barlcays Downgrade Article.
[174] Moody's, "Announcement: Moody's: Despite falling battery costs, consumers unlikely to defect from utilities," January 6, 2015 (Moody's Article), available at https://www.moodys.com/research/Moodys-Despite-falling-battery-costs-consumers-unlikely-to-defect-from--PR_315969.
[175] Moody's Article.
[176] Moody's Article.
[177] Deloitte, *The Math Does Not Lie: Factoring the future of the U.S. electric power industry*, Deloitte Center for Energy Solutions, October 22, 2012, 1.

Figure 4.3. Historical and Forecasted U.S. Electricity Demand Growth Rates in EIA's 2014 Annual Energy Outlook Reference Case (percent)



Source: EIA Annual Energy Outlook 2014, Figure MT-29, p. MT-16

Additionally, if the EPA Clean Power Plan is implemented in something like its current form, there will be a further incentive for energy efficiency, reducing demand growth further. As discussed in chapter 2 of this report, the Clean Power Plan assumes that one way to reduce carbon emissions is by energy efficiency measures of between 1.0 and 1.5 percent annually. Any additional energy efficiency measures from potential Clean Power Plan regulations are not accounted for in EIA's projections, which assumes current law.

3. Rising Expected Capital Expenditures by Utilities

Utilities also may face financial pressure in the form of rising capital expenditures to maintain the grid, environmental compliance, and cyber and physical security. We have noted these concerns in past Looking Forward Reports. Specifically, we have noted that, by one estimate, "the electricity industry is expected to spend over $2 trillion between 2010 and 2030 for environmental compliance and upgrading the grid."[178] We have seen estimates of utility spending on cybersecurity of up to $79 billion by 2020.[179] We have noted that such increases in capital expenditures by utilities – especially in conditions of flat or slow demand growth – could lead to rate increases, which could make decentralized technologies more attractive.

E. Regulatory Initiatives Allowing Decentralized Technologies to Compete with Utilities

[178] 2014 Looking Forward Report, 67.
[179] 2014 Looking Forward Report, 44-45.

A fourth area of activity related to decentralization and its attempts to compete with centralized power involves the regulation of utilities. Utilities may resist integrating decentralized technologies into their operations because the typical regulatory structure does not necessarily provide incentive to do so. Regulations tend to provide utilities with a stable way to earn a return for building more centralized generation and for investing in distribution and transmission systems. Changing utility incentives and providing decentralized technologies and new business models a chance to compete may require a new regulatory approach.

One such example of a regulator seeking to revise the role of the traditional electric utility is New York's Reforming the Energy Vision (REV) initiative. This is an example of a major state regulator – the New York Public Service Commission, or New York PSC – which seeks to "reform New York State's energy industry and regulatory practices" to "promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, wider deployment of 'distributed' energy resources, such as micro grids, on-site power supplies, and storage."[180] This effort – while not finalized and still under consideration – seeks to establish markets at the utility distribution level that allow and encourage the customer side of the grid to be on par with centralized generation and the bulk energy system.

REV requires utilities to modernize infrastructure and operations, particularly communications and data management, to allow more participation by customers and third parties. As described by the New York PSC, "Each utility will serve as the platform for interface among its customers, aggregators, and the distribution system… Simultaneously the utility will serve as a seamless interface between aggregated customers and the [New York Independent System Operator, or NYISO]," while NYISO wholesale markets "will evolve to properly value load management," including distributed generation.[181] The New York PSC went on to say that:

> Distribution utilities will play a pivotal role, representing both the interface among individual customers and the interface between customers and the bulk power system. The utility as Distributed System Platform Provider (DSPP) will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk system, while reducing the need for expensive investments in the distribution system as well. The function of the DSPP will be complemented by competitive energy service providers; both generators of electricity and retailers of commodity will expand their business models to participate in Distributed Energy Resources (DER) markets coordinated by the DSPP.[182]

This effort will require revising the existing regulatory paradigm. On February 26, 2015, the New York PSC adopted a "policy framework" for the development of markets for distributed energy resources. This framework restricts utility ownership of distributed energy resources to (a) resources located on utility property, (b) where a market for such technology does not already

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[180] New York Public Service Commission, "14-M-0101: Reforming the Energy Vision," available at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument.
[181] *Order Adopting Regulatory Policy Framework and Implementation Plan*, CASE 14-M-0101, State of New York Public Service Commission, February 26, 2015 (February REV Order), 12.
[182] *Order Instituting Proceeding*, Case 14-M-0101, State of New York Public Service Commission, April 25, 2014, 9.

exist (such as in low and moderate income households), or (c) for demonstration projects. This framework also instructs the utilities to make it much easier for customers to interact with the utility and obtain interconnection approvals for distributed resources. As part of this effort New York electric utilities are each required to file a Distributed System Implementation Plan by December 15, 2015. At that time, customers should be able to apply online for approval of smaller distributed energy systems such as residential solar, with automatic and timely impact studies and final decision.[183] In addition to developing new markets, the REV initiative will develop new utility ratemaking that provides incentives for utilities to connect more distributed resources. New York PSC Staff are scheduled to issue a straw proposal on ratemaking on June 1, 2015.[184]

In its REV initiative, the New York PSC is "informed by" regulatory developments in several jurisdictions, including "integration of distributed resources in California and Hawaii, consumer markets and emerging technologies in Texas, grid modernization in Massachusetts, and performance ratemaking in Minnesota and the United Kingdom." REV also notes the research, demonstrations, and expertise from U.S. national laboratories and the Electric Power Research Institute.[185]

F. Conclusion

To sum up, there is a significant amount of activity underway in the area of decentralized technologies. Costs distributed generation, storage, and other decentralized technologies have come down; private businesses are spurring innovation in delivering distributed electricity services via new business models; and regulators are looking at new ways of taking advantage of the opportunity that decentralized technologies may provide by developing new regulations that give decentralized technologies the chance to compete with traditional utilities. Utilities, meanwhile, may be under financial pressure by potential competition from decentralized resources – among other financial pressures – as highlighted by the Barclays downgrade of the electric utilities sector. If this trend continues, it may impact the transmission needs of the traditional bulk energy system. The Board should stay informed to be able to stay ahead of these developments. First, to stay abreast of ongoing developments, the Board could reach out to SPP utility members for information on developments in distributed generation in their areas. Second, the Board should note what is happening in other regions of the country that are experimenting with new, decentralized energy services, in regions and markets where electricity from traditional, centralized utility generation is highest in cost and where state regulators are doing the most to reform utility regulations. For example, utilities in Hawaii are already under pressure from distributed solar installations because of Hawaii's favorable climate and high average price of residential power.[186] Other states deserving of attention may include California – which is typically more likely to develop aggressive public policy – and New York, with an eye toward its REV initiative. By keeping abreast of some of the key developments in these

[183] February REV Order, Appendix B, 5.
[184] February REV Order, 131.
[185] *Order Adopting Regulatory Policy Framework and Implementation Plan*, CASE 14-M-0101, State of New York Public Service Commission, February 26, 2015, 13-14.
[186] The average residential power price in Hawaii was almost 35 cents per kWh for December 2014 according to EIA Electric Power Monthly, Table 5.6.A, March 4, 2015.

states going forward, the Board will be better prepared if advances in distributed technology and regulatory reform are successful and these challenges come to SPP.

V. Physical Grid Security

A. Introduction

In April of 2013, there was a well-documented and high profile physical attack on one of Pacific Gas and Electric Company's high voltage substations that supplies power to the Silicon Valley. Gunmen arrived in the vicinity of the substation undetected and then opened fire at the substation for 19 minutes. Before police arrived on-site, the gunmen were able to flee without being apprehended. Since the incident, nobody has been arrested or charged. The attack resulted in 17 high voltage transformers being damaged and grid operators having to reroute power around the site and asking power plants in the Silicon Valley to generate more electricity to avoid a blackout.[187]

In March of 2014, a leaked FERC analysis heightened concerns about sabotage. The report identified 30 critical high voltage transformer substations across the continental U.S. The

[187] The Wall Street Journal, "Assault on California Power Station Raises Alarm on Potential for Terrorism," The Wall Street Journal, accessed February 23, 2015, available at http://www.wsj.com/articles/SB10001424052702304851104579359141941621778.

analysis noted that disabling as few as nine of these substations during a time of peak electricity demand reportedly could cause a "coast-to-coast blackout."[188]

Since then, FERC and NERC have taken action to define new regulatory standards for physical grid security. Reliability Standard CIP-014-1 was approved in November 2014 to enhance physical security measures for the most critical bulk power system facilities.[189] Notably, the substation attack and the FERC analysis have brought significant attention to and intensified a nation-wide discussion about the vulnerabilities of the grid and how to prevent and mitigate the impacts of future attacks. In this section, we point to key findings from a report by the Congressional Research Service and a white paper from Battelle.[190]

B. Vulnerabilities to Physical Attacks

In the United States, the electric power grid is comprised of over 9,000 electric generating units connected to over 200,000 miles of high voltage transmission lines rated 230 kilovolts (kV) or greater that are supported by large towers.[191] Within this network of high voltage lines are large transformers that allow voltage levels to be adjusted to efficiently and safely move power across the network. The importance of high voltage transmission is that greater amounts of electricity can be delivered with fewer losses. High voltage transformers make up less than 3 percent of transformers in substations across the U.S., but manages the flow of 60 percent to 70 percent of the nation's electricity,[192] thus serving as critical nodes in the network and the backbone of the electric power grid. Figure 5.1 shows a map of the high voltage transmission system with the colored lines representing different levels of voltage and the dots representing substations.

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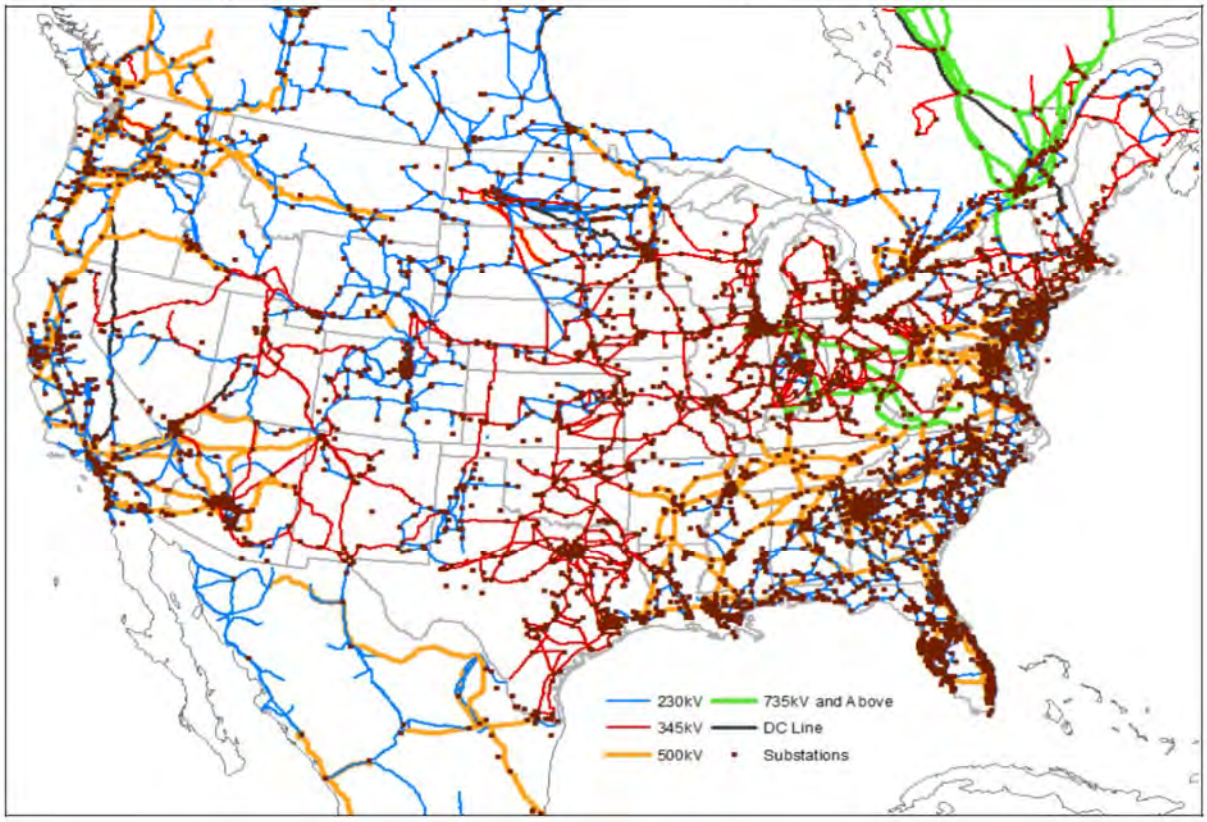
[188] Paul W. Parfomak, *Physical Security of the U.S. Power Grid: High –Voltage Transformer Substations*, Congressional Research Service, June 17, 2014, 6.
[189] Final Rule on Physical Security Reliability Standard, Order No. 802, 18 CFR Part 40 (November 20, 2014), 149 FERC ¶ 61,140 (2014).
[190] Paul W. Parfomak, *Physical Security of the U.S. Power Grid: High –Voltage Transformer Substations*, Congressional Research Service, June 17, 2014 and Battelle, *Recommendations for Implementing Comprehensive Bulk-Power System Security Standards*, May 20, 2014.
[191] Paul W. Parfomak, *Physical Security of the U.S. Power Grid: High –Voltage Transformer Substations*, Congressional Research Service, June 17, 2014, 1.
[192] Ibid., 1.

Figure 5.1. High Voltage Transmission System of the U.S.[193]



Source: Congressional Research Service

According to the Congressional Research Service report, high voltage transformers are considered to be the most vulnerable to an intentional physical attack.[194] Their susceptibility is primarily due to their size, design, and location. The size of a transformer is generally tied to the level of its rated voltage. For example, transformers that are used to step down voltages for residential use are small enough to be mounted on a pole.[195] On the other hand, a three-phase 765 kV transformer could be the size of an average new single-family house.[196] At such a massive size, they are easy to identify and, therefore, easy targets for a physical attack.

The design of a transformer, regardless of size, basically consists of the essential voltage transforming elements of copper wire windings wrapped around a metallic core that is insulated and housed in a protective casing that is typically made from 5/8 to 3/4 inch thick steel.[197] A gunshot powerful enough to penetrate the steel casing could easily cause irreparable damage to the transformer. Furthermore, larger transformers generate waste heat during operation, so they are equipped with a cooling system that involves circulating oil and external radiators. A 345 kV transformer may be equipped with 29,000 gallons of cooling oil.[198] The cooling oil is usually

[193] Ibid.
[194] Ibid., 2.
[195] Ibid.
[196] Ibid., 4.
[197] Ibid., 3.
[198] Ibid.

contained in an external tank to the main transformer casing. If the cooling oil tank is penetrated by a gunshot, the oil would ignite and cause fire damage to the substation.[199]

High voltage transformers are located in network substations where transmission lines meet and other electric equipment are installed. Such substations may be found near electric generating plants, urban centers, or in remote locations. Depending on the location, security and the number of personnel on-site may vary. Substations in remote locations may have minimum security features and may lack a human presence. Often, substations are not guarded during normal operating circumstances and are simply enclosed by chain-link fence.[200] Even with visual monitoring devices for detecting intrusion, if someone is able to get beyond the fencing, the response time for law enforcement to arrive may not be quick enough to prevent sabotage.

The Congressional Research Service states that "the main risk from a physical attack against the electric power grid – primarily towers and transformers – is a widespread power outage lasting for days or longer."[201] This points to a big challenge with respect to replacing multiple high voltage transformers that could be damaged or rendered inoperable from such a physical attack. Most high voltage transformers are unique and are custom designed and manufactured for specific network requirements and, therefore, generally cannot be interchanged.[202] Consequently, the lead times from procurement to delivery of a new high voltage transformer can range from five to 12 months for domestic production and six to 16 months for foreign production.[203] If demand is high, lead times can be greater than 18 months.[204]

High voltage transformers are also high cost. According to the Congressional Research Service, depending on rated voltage and configuration, a single transformer can range from $2 million to $7.5 million before transportation and installation costs.[205] Given the cost, physical attributes, and life expectancy of each unit, which is estimated to be 38 to 40 years,[206] it is not practical for utilities to carry spare high voltage transformers.

Finally, the sheer size of high voltage transformers presents logistical challenges in terms of transporting a unit to its intended site. Because of their weight and dimensions, there are few transportation options and most high voltage transformers have to be transported by special railcars, of which there are only about 30 in North America.[207] As a result, in an emergency situation, it could be difficult expediting transportation for a replacement transformer.[208]

C. Recommendations

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[199] Ibid., 7.
[200] Ibid.
[201] Ibid., 2.
[202] Ibid., 7.
[203] U.S. Department of Energy, *Large Power Transformers and the U.S. Electric Grid*, April 2014, 9.
[204] Ibid.
[205] Paul W. Parfomak, *Physical Security of the U.S. Power Grid: High –Voltage Transformer Substations*, Congressional Research Service, June 17, 2014, 6.
[206] U.S. Department of Energy, *Large Power Transformers and the U.S. Electric Grid*, April 2014, 28.
[207] Ibid., 10.
[208] Paul W. Parfomak, *Physical Security of the U.S. Power Grid: High –Voltage Transformer Substations*, Congressional Research Service, June 17, 2014, 8.

While there are certainly risks to the electrical power grid from a physical attack on a high voltage transformer as was evidenced by the 2013 attack on Pacific Gas and Electric's substation, it did not result in a widespread and sustained blackout. In fact, as previously discussed, the impact was mitigated by the response to the situation, by rerouting power around the substation and increasing generation at load. Even with the potential for a coordinated attack on multiple high voltage transformers that could lead to a catastrophic blackout, it would require "acquiring operational information and a certain level of sophistication on the part of potential attackers."[209] Furthermore, Battelle, in a white paper responding to a 2014 FERC Order directing NERC to develop reliability standards for physical security of the bulk power system, states that "there remain several other threats which are equally or more significant in terms of potential impacts, and with a much higher likelihood of occurrence based on historical observations."[210] Battelle further states that "environmental events (storms, earthquakes, etc.) and equipment and operational failures, in particular, are historically far more likely than physical attacks. Storms and earthquakes are also much more likely to create widespread, nearly simultaneous impacts (e.g., Hurricane Sandy) than even a large scale, coordinated terrorist attack."[211] Accordingly, Battelle believes that a comprehensive approach to identifying vulnerabilities will lead to investments in security that are more cost-effective across a range of threats.[212]

We believe that improving defensive measures and deterrents to physical attacks are important, but because all future attacks may not be preventable, resiliency should be emphasized. Investments in resiliency would allow the affected transmission system to recover faster by incorporating enhanced grid management and control software and systems, additional protection equipment and redundancies through additional transmission lines or substations. Terry Boston, chief executive officer of PJM, shared a similar sentiment in a recent presentation to the National Association of State Energy Officers, urging caution with investments that just harden infrastructure and saying that redundancy and resiliency of the grid is far more important than physical security.[213] In any case, planned investments in physical security should be compared to alternatives that increase the resiliency of the grid by determining which investments provide the greatest system-wide net benefits.

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[209] Ibid., 26.
[210] Battelle, *Recommendations for Implementing Comprehensive Bulk-Power System Security Standards*, May 20, 2014, 3.
[211] Ibid.
[212] Ibid.
[213] Terry Boston, "21st Century Power Grids: Reliable, Controllable and Resilient," Presented at the 2015 National Association of State Energy Officials Energy Policy Outlook Conference in Washington, D.C., February 5, 2015 (Boston NASEO Presentation).

VI. Blurred Jurisdictional Lines

A. Introduction

In 2013, judges in two separate decisions in U.S. District Court – one in New Jersey, the other in Maryland – ruled that federal law preempted state law with respect to important resource choice decisions. In both cases, the states sought long-term contracts for new generating capacity through competitive procurements because of reliability concerns for their ratepayers. The basis for both judges' decisions to preempt the states was that FERC alone could determine wholesale rates for electricity, and that states' long-term procurement efforts in these two cases violated the Supremacy Clause of the U.S. Constitution. The courts' logic could destabilize the jurisdictional coexistence between states and the federal government, as many state programs use a similar structure to those in New Jersey and Maryland.

Since then, there have been additional developments in the split between state and federal jurisdiction in the electricity business. These developments, which we explain in turn, could have additional negative impacts. Below, we explain each of the jurisdictional issues, including (a) resource adequacy, (b) demand response, (c) distributed generation, and (d) consideration of emissions in system dispatch. We conclude with one potential solution below to the jurisdictional split between state and federal regulators, i.e., that jurisdiction be split on long-

term (states) vs. short-term (FERC).

B. Jurisdictional Issue 1: Resource Adequacy

In 2011, regulators in New Jersey and Maryland had a problem. Both states, which relied heavily on imported power from elsewhere on the transmission grid, had been warned by PJM and some utilities that because of delays in the expected completion dates for new transmission projects, both states might face significant capacity shortfalls and even the possibility of brownouts or rolling blackouts. Making matters worse, (a) both states' generation portfolios were aging and a significant portion was at risk for retirement, (b) load for both states were volatile and difficult to predict, and (c) both states had aggressive renewable portfolio standards that required conventional generation to support its intermittent nature.[214]

This threat to reliability was not supposed to happen in New Jersey and Maryland, since both states were participants in PJM's wholesale markets, including its capacity market, the Reliability Pricing Model, or RPM. RPM was designed to attract investment in new generation when and where it was needed, but in the eyes of Maryland and New Jersey regulators, RPM was not delivering local, conventional generation to serve its states' ratepayers. So, Maryland and New Jersey each conducted competitive procurement for new gas-fired generation, a function open only to the states—neither FERC nor PJM can order new generation to be built. These procurements resulted in contracts for almost 2,000 MW of new gas-fired generation for New Jersey and 661 MW in Maryland.

Numerous parties, mostly companies owning generation elsewhere in PJM, challenged these contracts in cases that reached U.S. District Court. The plaintiffs in both cases argued that because FERC had created a capacity market within PJM, the states were preempted from playing their traditional role in resource planning. In the Maryland case, the judge found that the Maryland procurement violated the Supremacy Clause of the U.S. Constitution because it "set" prices for sales of wholesale capacity and energy,[215] and in New Jersey, the judge concluded the same.[216] Both states appealed the respective decisions; separate court decisions denied both appeals.[217] Both states have petitioned the U.S. Supreme Court for consideration of the two decisions.[218] The states will have to convince the Supreme Court that the New Jersey and Maryland decisions were bad law. Regardless of whether they succeed, the decisions can have negative policy implications.[219] Again, only states can order new generation to be built; FERC

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[214] Craig R. Roach, Ph.D., Frank Mossburg, Vincent Musco, "Partnership, Not Preemption," *Public Utilities Fortnightly*, December 2013 (Boston Pacific PUF Article).
[215] "Memorandum of Decision," *Case 1:12-cv-01286MJG*, In the U.S. District Court for the District of Maryland, Sept. 30, 2013, 111-112.
[216] "Memorandum," *Civil Action No. 11-745*, In the U.S. District Court for the District of New Jersey, Oct. 11, 2013, 54.
[217] United States Court of Appeals for the Third Circuit, Case No. 12-4330, September 11, 2014; United States Court of Appeals for the Fourth Circuit, Case No. 13-2419, May 13, 2014.
[218] "Petition for a Writ of Certiorari," *CPV Power Development, Inc., et al. v. PPL EnergyPlus, LLC, et al.*, February 11, 2015; "Petition for a Writ of Certiorari," *Douglas R. M. Nazarian, et al., v. PPL EnergyPlus, LLC, et al.*, February 11, 2015.
[219] Boston Pacific PUF Article, 35.

and the RTOs can only set up markets that provide incentives to build new generation when and where it is needed.

Some data suggests, however, that FERC-jurisdictional capacity markets may not be working as planned. According to the American Public Power Association, 97.6 percent of new capacity that was built in 2013 was either utility- or customer-built, or backed by a long-term, power purchase agreement (PPA).[220] Of the remaining 2.4 percent of that capacity, the "vast majority" received external funding such as grants from the American Reinvestment and Recovery Act or a state or foundation.[221] In other words, "just 0.1% of the new capacity was constructed for sale into the markets without any supplemental assistance."[222] Moreover, the American Public Power Association notes that "when broken down geographically, only 6% of all capacity constructed in 2013 was built within the footprint of the RTOs with mandatory capacity markets."[223]

Even in periods of high prices, RTO capacity markets have not always delivered new generation when and where it is needed. For example, in the instances of New Jersey and Maryland, average prices as high as $167.91/MW-day and $177.04/MW-day, respectively, were not enough to attract significant, local investment in new generation; instead, capacity bids in PJM were largely from demand response and deferred retirements of existing generation.[224] This is because RTO capacity markets are short-term in nature; in PJM, for example, generators receive a one-year contract three years in advance. In contrast, state procurements of new generation offer long-term contracts, often 10-, 15-, or 20-year PPAs. No wonder, then, the American Public Power Association data is so skewed toward utility-builds and long-term PPAs.

If the New Jersey and Maryland decisions are not overturned by the Supreme Court, states that participate in wholesale capacity markets may no longer have the tools to mitigate long-term threats to reliability for their ratepayers. This could challenge such states going forward. NERC has forecasted resource adequacy shortfalls over the coming years for multiple organized markets, including New York ISO, MISO, and the Electric Reliability Council of Texas, or ERCOT,[225] while both ISO New England[226] and PJM[227] have proposed "enhancements" to their capacity market design to increase reliability and mitigate concerns following poor capacity resource performance during the winter of 2013-2014.

For SPP states and others like them, they may be wise to avoid capacity markets altogether and maintain jurisdiction over resource adequacy and new generation. But the courts' decisions on federal preemption as it relates to resource adequacy could have negative impacts

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[220] "Power Plants are not Built on Spec," American Public Power Association, 2014 (APPA Report), 2.
[221] APPA Report, 2.
[222] APPA Report, 2.
[223] APPA Report, 1.
[224] Boston Pacific PUF Article, 39, Figures 3, 4.
[225] "2014 Long-Term Reliability Assessment," North American Electric Reliability Corporation, November 2014, 4-6.
[226] *ISO New England, Inc.*, 147 FERC ¶ 61,172 (2014).
[227] "PJM Unveils Proposed New Generation Capacity Performance Market," COMPETE, December 17, 2014, available at http://www.competecoalition.com/blog/2014/12/pjm-unveils-proposed-new-generation-capacity-performance-market.

for all states, not just those in organized capacity markets. States' efforts to procure (a) full requirements electricity service for its default service customers, (b) renewable resources pursuant to state Renewable Portfolio Standards, (c) demand-side products, (d) peaking capacity, and (e) utility rate-base generation could all be in danger if the New Jersey and Maryland cases are not overturned.[228] This is because each of these state actions sets the price paid for an electricity product – substituting a state price for a federal price – an action that the courts say is in violation of the Supremacy Clause of the U.S. Constitution.[229] SPP should stay aware of the outcome of the state appeals to the Supreme Court.

C. Jurisdictional Issue 2: Demand Response

A second major decision related to the state-federal jurisdictional split came in May 2014, when the D.C. Court of Appeals issued a split decision[230] to vacate FERC Order No. 745.[231] Order No. 745 required RTOs and ISOs to compensate demand response providers at full locational marginal prices in the energy market.[232] The Court's decision focused primarily on a jurisdictional argument, deciding that demand response is a retail transaction, not a wholesale transaction, and thus is under the sole jurisdiction of the states, not FERC.[233] The D.C. Court of Appeals later heard and denied a petition for en banc review of its decision.[234]

The Court's decision effectively rejects FERC's attempt to regulate demand response in the wholesale energy market on purely jurisdictional grounds, noting that "FERC's authority over demand response resources is limited: its role is to assist and advise state and regional programs."[235] Unlike the New Jersey and Maryland capacity cases, in which the courts ruled for federal preemption of state action, here, the Court determined jurisdiction over demand response in the energy markets is state jurisdictional.

Similar to the potential impacts of the New Jersey and Maryland cases, the implications from the demand response decision could be substantial. In January 2015, FERC appealed the case to the U.S. Supreme Court,[236] arguing that the D.C. Court of Appeals decision "threatens significant damage to the Nation's wholesale-electricity markets,"[237] is contrary to FERC's "statutory responsibility to ensure that [wholesale] rates are just and reasonable,"[238] and that the decision's holdings "throws into serious question whether FERC may review any of the rules established by wholesale-market operators to govern demand-response participation—or perhaps

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[228] Boston Pacific PUF Article, 40-41.
[229] Boston Pacific PUF Article, 40.
[230] *Electric Supply Ass'n v. FERC*, No. 11-1486, et al. (D.C. Cir. May 21, 2014).
[231] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187 (March 15, 2011) (Order No. 745).
[232] Vincent Musco, "Back to Basics on Demand Response Compensation," *BPC In Brief*, October 17, 2014, available at http://www.bostonpacific.com/back-basics-demand-response-compensation/.
[233] Ibid.
[234] "Appeals court denies rehearing on FERC Order 745," Restructuring Today, September 18, 2014.
[235] D.C. Cir. May 21, 2014, 12a-14a.
[236] "Petition for a Writ of Certiorari," *Federal Energy Regulatory Commission vs. Electric Power Supply Association, et al.*
[237] Ibid., 29.
[238] Ibid., 30.

even whether it has authority to permit the participation of demand-response providers in wholesale-electricity markets at all."[239]

Indeed, while the D.C. Court of Appeals decision applied only to the energy markets, focus among market participants, RTOs, and regulators quickly turned to the capacity markets, where demand response participation is much greater than in the energy markets, and thus is a larger concern. PJM, for example, which cleared 11,000 MW of demand response in its most recent capacity auction, is involved in a proceeding regarding the potential extension of the D.C. Court of Appeals decision to the capacity markets. FirstEnergy, a utility in PJM, filed a complaint at FERC requesting that PJM nullify all existing terms in the PJM tariff allowing demand response resources to participate in PJM's capacity markets and that PJM recalculate the results of its most recent capacity auction without demand response participation.[240] A similar complaint was filed in ISO New England by the New England Power Generators Association, focusing only on future capacity auctions.[241]

Undoubtedly, there is significant uncertainty surrounding demand response. The D.C. Court of Appeals granted FERC's request and issued a stay of the mandate while FERC pursues its appeal at the Supreme Court.[242] FERC, in the meantime, is (a) pursuing its appeal to the Supreme Court, (b) continuing to regulate demand response as if it has the jurisdiction to do so, as evidenced by its recent approval of the integration of demand response into ISO New England's operating reserve and forward reserve markets,[243] and (c) is engaged in behind-the-scenes preparation for how to proceed if its petition to the Supreme Court is unsuccessful.[244]

For SPP, where demand response participation is smaller and there is no capacity market, this issue has less impact. However, as we have pointed out in the past, demand response participation can provide significant benefits for SPP ratepayers and the Integrated Marketplace introduces new opportunities for demand response resources and forecasted demand response participation in SPP continues to rise.[245] SPP will want to be aware of the ultimate resolution of this case; if upheld, the states will take over exclusive jurisdiction of demand response, and RTOs will be forced to find innovative ways to accommodate and encourage continued participation of demand response programs. PJM, for example, has developed a "contingency measure" if the Supreme Court appeal is unsuccessful that would allow entities to submit "curtailment commitment bids" that would reduce the amount of capacity PJM procures in the next capacity auction in May.[246]

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[239] Ibid., 30-31.
[240] *Complaint of First Energy Service Company*, FERC Docket No. EL14-55-000, May 23, 2014 (FirstEnergy Complaint).
[241] *Complaint of the New England Power Generators Association, Inc.*, FERC Docket No. EL15-21-000, November 14, 2014.
[242] "FERC's Order 745 – Still In Effect For Now," Seth Jaffe, Law & The Environment, October 24, 2014, available at http://www.lawandenvironment.com/2014/10/24/fercs-order-745-still-in-effect-for-now/.
[243] 150 FERC ¶ 61,007, January 9, 2015. FERC stated at paragraph 29: "While we acknowledge that the [D.C. Court of Appeals] decision creates uncertainty for demand response resources in FERC-jurisdictional wholesale markets, we find it appropriate at this time to proceed with these market enhancements until further action is taken."
[244] Comments of Cheryl LaFleur, 2015 NASEO Energy Policy Outlook Conference, February 5.
[245] 2013 Looking Forward Report, 6.
[246] "PJM to File Post-EPSA Demand Response Contingency Plan with FERC," RTO Insider, December 22, 2014, available at http://www.rtoinsider.com/pjm-epsa-demand-response-11783/.

Moreover, the decision on demand response represents another jurisdictional case where the court's interpretation of the law may be correct, but the policy implications are bad. FERC (and the RTOs) had successfully integrated substantial demand response into wholesale markets across the country. Much of that progress could now be undone. Worse, unlike the New Jersey and Maryland capacity cases, states do not necessarily want exclusive jurisdiction over demand response. Indeed, several states filed petitions in support of FERC's appeals, arguing that demand response helps lower ratepayer costs and improves reliability.[247] At the conclusion of this chapter, we address a potential solution to this concern.

D. Jurisdictional Issue 3: Distributed Generation

A third, potential front in the jurisdictional divide between states and the federal government could be sales from distributed generation. While the discussion of distributed generation can often focus on how such resources are compensated – net metering policies, grid reliability charges, etc. – a more fundamental question may require attention: are sales by retail customers with distributed generation resources back to the grid a wholesale or retail transaction?

Distributed generation resources differ from centralized generators in their need for the transmission grid to deliver their power. Centralized generators use the high voltage grid to deliver power to load; distributed generation resources do not, instead providing power directly to the local distribution grid. This creates the possibility that sales from distributed generation resources are retail transactions that should not be subject to FERC jurisdiction, according to a recent article in the *Electricity Law Journal*.[248]

The Lindh-Bone Article explains that today, sales from distributed generation resources are considered FERC-jurisdictional. The authors explain that generators seeking to interconnect to the grid (including distributed generators) are subject to "FERC jurisdiction…when the planned interconnection is to a facility already subject to an [Open Access Transmission Tariff] and made for the purpose of either transmitting in interstate commerce or selling at wholesale in interstate commerce."[249] Further, the authors note that FERC has made it clear that it asserts jurisdiction "[o]nly if the end-use customer…is considered to have made a net sale of energy to a utility…"[250] Only sales from Qualifying Facilities are exempted from FERC jurisdiction.[251]

The authors assert that this approach to jurisdiction of sales from distributed generation is flawed. They claim that "the states have complete authority, emanating from their organic police powers, to regulate not only the rates and terms of such sales, but also the terms by which the

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[247] The Maryland Public Service Commission stated that if the "decision goes into effect…we anticipate adverse consequences" and that "reliability could be affected on peak demand days." The Delaware Public Service Commission stated that "unnecessary costs" may be passed on to Delmarva ratepayers, and that Delmarva may fail "to achieve its statutory goals regarding energy efficiency and peak load reduction." "What the FERC Order 745 Ruling Means for Demand Response," Claire Cameron, Utility Dive, July 17, 2014, available at http://www.utilitydive.com/news/what-the-ferc-order-745-ruling-means-for-demand-response/287071/.

[248] Frank R. Lindh, Thomas W. Bone, Jr., "State Jurisdiction over Distributed Generators," *Energy Law Journal*, Volume 34, No. 2, December 16, 2013 (Lindh-Bone Article).

[249] Lindh-Bone Article, 521.

[250] Lindh-Bone Article, 522.

[251] Lindh-Bone Article, 521.

generators interconnect to the distribution grid."[252] They claim that, in its past rulings, FERC has improperly assumed that "all wholesale sales on the interconnected grid in North America…occur in interstate commerce" including "a residential photovoltaic system, servicing a retail customer receiving and exporting power solely from and to local distribution facilities," thus subjecting such customers to FERC jurisdiction.[253] The authors argue that a sale from distributed generators that "occurs on local distribution facilities to satisfy a buyer's loads collocated on the local distribution facilities" is an "intrastate wholesale" transaction that should be considered "state jurisdictional."[254] The authors conclude that it was "Congress's intent" to exempt from federal regulation energy sales not occurring in interstate commerce,[255] noting the FPA's clear language that "[FERC]…shall not have jurisdiction…over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce." [256] Thus, say the authors, FERC's "interpretation of its jurisdiction disregards the potential for such intrastate wholesales" and "impermissibly writes out of the statute the 'local distribution' exemption from federal jurisdiction."[257]

To date, the issue of distributed generation's participation in selling electricity has focused on policy, not jurisdiction. As we note in chapter 4, net metering rules and grid access charges – driven by state public policy – has been a major driver of investment in distributed generation and has been a primary part of discussion about distributed generation. Going forward, however, this could be an emerging jurisdictional issue with real consequences for states and customers. In California, for example, FERC rejected a request by the California Public Utilities Commission (CPUC) "to confirm that a 'feed-in tariff' promulgated by the CPUC under a [California] statute…was lawful and not preempted by federal law."[258] The feed-in tariff would set CPUC-jurisdictional prices for power from generators 20 MW or less that met certain environmental requirements.[259] FERC found, however, that this action by the CPUC would represent "impermissible wholesale rate-setting by the CPUC" because it would set rates "for wholesale sales in interstate commerce by public utilities" and is thus "preempted by the [Federal Power Act]."[260] One party made the argument that "sales of power under distribution-level feed-in tariffs cannot be interstate commerce because the power sold does not enter the bulk transmission system or interstate commerce, but remains on the state-regulated distribution system."[261] FERC disagreed, noting that its authority from the Federal Power Act "to regulate sales for resale of electric energy and transmission in interstate commerce is not dependent on the location of generation or transmission facilities, but rather on the definition of…wholesale sales contained in the Federal Power Act."[262]

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[252] Lindh-Bone Article, 499.
[253] Lindh-Bone Article, 522.
[254] Lindh-Bone Article, 525.
[255] Lindh-Bone Article, 525.
[256] Lindh-Bone Article, 539, citing 16 U.S.C. § 824(b)(1) (2012).
[257] Lindh-Bone Article, 525.
[258] Lindh-Bone Article, 522-523.
[259] Lindh-Bone Article, 523.
[260] Lindh-Bone Article, 523.
[261] *California Pub. Utils. Comm'n.,* 132 FERC ¶ 61,047 (2010) (FERC CPUC Order), 56.
[262] FERC CPUC Order, 72.

E. Jurisdictional Issue 4: Considering Emissions in Dispatch

Another potential jurisdictional issue that could be coming the Board's way soon involves compliance with EPA's proposed Clean Power Plan. However, this issue is less about federal versus state jurisdiction, than the overlapping regulations of two federal agencies.

Under the Federal Power Act, SPP's rates must meet the "just and reasonable" standard. Soon, SPP and the other RTOs may also be required to help states meet emissions reductions included in EPA's Clean Power Plan. This, in theory, could complicate RTOs' efforts as they attempt to meet the just and reasonable rates standard at FERC and help member states comply with the Clean Power Plan emissions reduction requirements. While we have not seen much evidence suggesting that RTOs will have trouble complying with these two federal standards (if the Clean Power Plan is adopted), we have seen plenty of activity among RTOs, state regulators, and policy experts on how best to meet the requirements of the Clean Power Plan while also maintaining efficiency in electricity markets.

In its draft Clean Power Plan, the EPA provides states with flexibility in meeting carbon reduction requirements, noting that "there are a number of different ways that states can design programs that achieve required reductions while working within existing market mechanisms used to dispatch power effectively in the short term and to ensure adequate capacity in the long term."[263] One method is to "monetize" the cost of compliance and "work within the least cost dispatching principles that are key to operation of our electric power grid."[264] In other words, RTOs like SPP can consider adding the cost of emissions to generators into its dispatch methodology.

In a recent paper, William Hogan argues that "pricing carbon is the only way to maintain the integrity of the electricity market design"[265] that is inherent in locational marginal pricing-based markets, like SPP's. However, Dr. Hogan warns that the "Clean Power Plan…[is] only loosely connected to the underlying social cost of carbon or the workings of electricity markets."[266] He suggests that a carbon tax is the "most direct means" to price carbon so that the "tax becomes part of the marginal cost for carbon emitting plants" allowing for "a seamless integration with short-run economic dispatch."[267] FERC Commissioner Cheryl LaFleur, in a recent speech, said that it is critical that the price signals of nodal markets not be compromised in accommodating the requirements of the Clean Power Plan.[268]

RTOs are preparing for this new complication in their role in dispatching the system. PJM, for example, has conducted an analysis of potential methods for meeting emissions reductions requirements of states in the PJM region through consideration of the cost of carbon.[269] In one scenario, PJM assumed a single price for carbon that is applied to all carbon-

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[263] Clean Power Plan, 34834.
[264] Clean Power Plan, 34834.
[265] William W. Hogan, "Electricity Market Design: Environmental Dispatch," Harvard Electricity Policy Group, December 4, 2012 (Hogan Paper), 6.
[266] Hogan Paper, 8.
[267] Hogan Paper, 5.
[268] Remarks of Cheryl LaFleur, 2015 Conference of the National Association of State Energy Officials, February 5, 2015 (LaFleur NASEO Speech).
[269] "EPA's Clean Power Plan Proposal Review of PJM Analyses Preliminary Results," PJM, November 17, 2014 (PJM CPP Presentation).

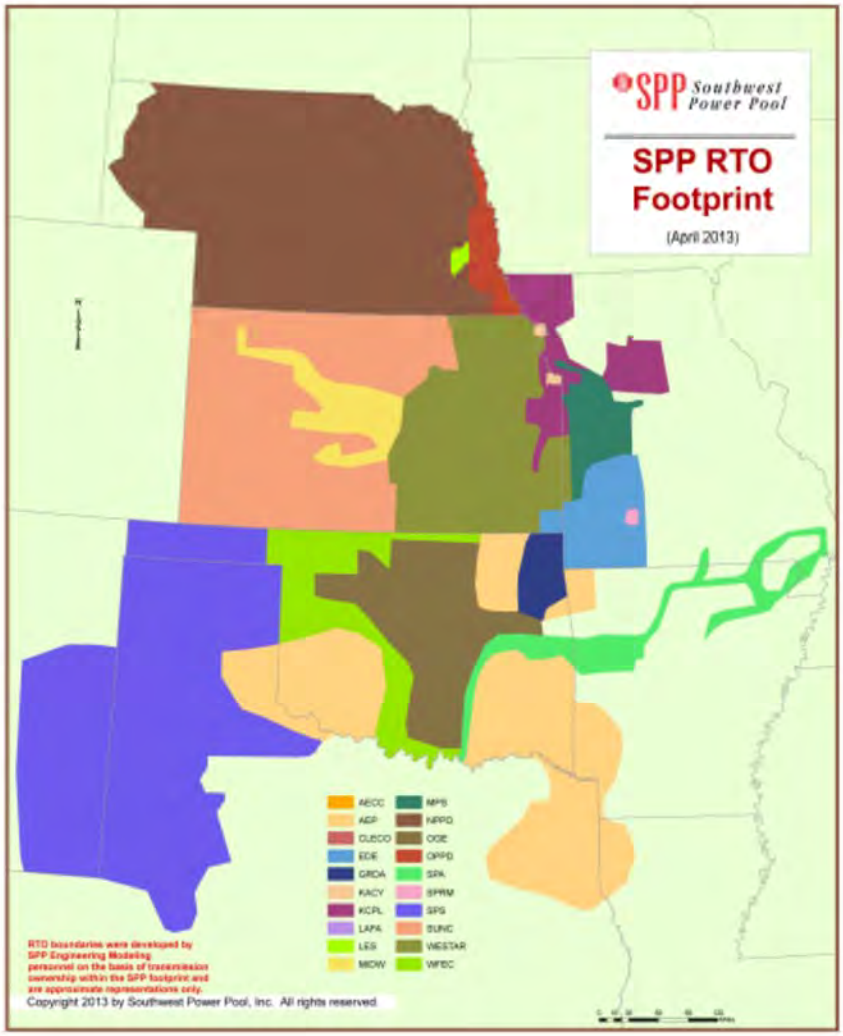
emitting generators across the PJM footprint; in a second, PJM assumed that each PJM state has its own unique price for carbon, whereby PJM applied a carbon price to each generator based on the state in which it is located.[270] In both instances, PJM dispatched resources across its footprint to determine the least cost mix to meet load while not violating emissions limits imposed by the Clean Power Plan.[271]

PJM's analysis may have important lessons for SPP. As noted earlier, under the draft Clean Power Plan, states will have flexibility in meeting emissions reductions requirements. That flexibility includes the possibility of collaboration between similarly-situated states – like states within the same RTO – to develop a uniform compliance strategy, such as a single, regional price for carbon to be included in market dispatch. PJM's analysis suggests that this approach – as opposed to an approach where each state has its own unique price for carbon – could result in lower carbon prices and lower overall costs to load.[272]

It therefore may be beneficial for SPP's states to collaborate in complying with the Clean Power Plan so as to maximize efficiencies in meeting state-by-state plans and helping SPP to continue meet its obligations under the Federal Power Act in providing reliable service at just and reasonable rates. To that end, SPP may want to consider serving as a forum for the states to collaborate on their individual compliance plans, perhaps by collaborating with the Regional State Committee. While potentially worthwhile, this may not be easy, especially because some SPP states are only partial participants in the SPP markets, such as in New Mexico (where one utility, Southwestern Public Service Company, is an SPP market participant and the rest of the state falls outside of any organized market) and Louisiana (where AEP is an SPP market participant but other utilities, like Entergy, are in another organized market, MISO). (SPP's RTO footprint is shown in Figure 6.1 below.) Moreover, FERC Commissioner Cheryl LaFleur recently suggested the possibility that utilities could end up switching RTOs if neighboring RTOs develop different compliance plans,[273] choosing the compliance plan they consider better suited for their interests and those of their ratepayers.

[270] PJM CPP Presentation, 33.
[271] PJM CPP Presentation, 33.
[272] PJM CPP Presentation, 35.
[273] LaFleur NASEO Speech.

Figure 6.1. SPP RTO Footprint



Even so, some have raised concerns about what the Clean Power Plan, if approved, will do to the jurisdictional landscape of the electricity business. FERC Commissioner Tony Clark, in testimony before the U.S. House of Representatives,[274] said that the proposed Clean Power Plan "has the potential to comprehensively reorder the jurisdictional relationship between the federal government and the states as it relates to the regulation of public utilities and energy development" and described the potential for a future "jurisdictional train wreck."[275] He stated:

> [E]ven if all states in a region band together under the regional grid operator, any changes to the wholesale markets must necessarily be vetted and approved by FERC. [FERC] would be charged with the awkward task of evaluating

[274] "Written Testimony of Commissioner Tony Clark, Federal Energy Regulatory Commission," Before the Committee On Energy and Commerce Subcommittee on Energy and Power, United States House of Representatives Hearing on FERC Perspective: Questions Concerning EPA's Proposed Clean Power Plan and other Grid Reliability Challenges," July 29, 2014.
[275] Ibid.

> fundamental wholesale market design changes driven by environmental priorities approved by the EPA. Yet FERC is an economic and reliability regulator. Any decisions made by FERC must be rooted not in the Clean Air Act, but in our 'just and reasonable' and 'not unduly discriminatory or preferential' rate standard in the Federal Power Act. FERC's ability to alter or reject an RTO-proposed compliance mechanism would present a conflict with EPA's evaluation of the compliance plans. Absent Congress stepping in and clearly defining FERC authority and EPA authority, it is not hard to envision a future jurisdictional train wreck.[276]

F. A Practical, Fair Jurisdictional Split

One potential clean split between federal and state jurisdiction that we have previously endorsed is to render to the states the market for long-term products (greater than one year) and leave short-term products to the federal government.[277] As we have explained elsewhere, short-term markets and long-term markets can and do coexist and benefit each other.[278] We provided the example of the housing market as illustrative:

> [I]n the housing market, there are renters and buyers. These are two different product markets. Buying a house is a long-term product. The buyer gets a guaranteed place to live and a guaranteed price in the form of a mortgage payment. The buyer, however, takes on the added risk of upkeep and a long-term financial commitment. Renting is a short-term product; a place to live isn't guaranteed beyond the rental contract and neither is the price, and the risks of long-term ownership aren't taken on. These markets are separate despite the fact that they "affect" each other. Buying a house that was a rental decreases the supply of houses for rent and could increase rental prices. Building too many houses for the long-term buying market could force a crash in the rental market if the new supply is converted into rentals. Despite this, no economist would propose shutting down the house-buying market to preserve a higher-priced rental market.[279]

Splitting jurisdiction in this manner between the states and the federal government may help mitigate some of the negative consequences that may be caused by the recent court cases in New Jersey, Maryland, and related to demand response. It would allow FERC to maintain its jurisdiction over its short-term capacity markets, like that in PJM, while also allowing states the ability to respond to long-term threats to reliability using existing authority over resource adequacy. FERC markets can protect against undue interference from long-term procurements by states through measures such as the Minimum Offer Price Rule in PJM, which prevents uneconomic entry. The short-term/long-term jurisdictional split would also allow FERC to continue regulating demand response – a result many states favor – which would preserve the gains made by demand response resources in recent years while also avoiding having to

[276] Ibid.
[277] Boston Pacific PUF Article, 36.
[278] Boston Pacific PUF Article, 36.
[279] Boston Pacific PUF Article, 41-42.

potentially unwind thousands of megawatts of demand response contracts. FERC could also retain its authority over sales from distributed generation resources that implicate interstate commerce.

VII. Thoughts on a Framework for Evaluating Transmission Investments

A. Introduction

One of the Board's most important functions is reviewing and approving transmission investments that expand and strengthen the grid so that system power can be more reliably and economically delivered to load. Those investments can be significant: in 2012, 2013, and 2014, SPP has issued "notice to construct" letters for new transmission projects totaling $1.52 billion,[280] $1.64 billion,[281] and $1.48 billion,[282] respectively. More recently, SPP approved another $270 million of additional transmission investment in early in 2015.[283]

This chapter explores five issues that may confront the Board as it considers proposed transmission investments going forward: (a) decentralized technologies, which have been suggested to be a competitive alternative to the grid; (b) exports of renewables, which often

[280] Southwest Power Pool, "2013 SPP Transmission Expansion Plan Report," January 29, 2013, 4.
[281] Southwest Power Pool, "2014 SPP Transmission Expansion Plan Report," January 6, 2014, 7.
[282] Southwest Power Pool, "2015 SPP Transmission Expansion Plan Report," January 5, 2015, 7.
[283] Rich Heidorn Jr., "Falling Oil Prices, Wind Exports Raise Concerns about SPP Transmission Expansion," RTO Insider, January 19, 2015 (RTO Insider Article).

require transmission investment and can complicate the assignment of costs to beneficiaries; (c) load forecasts, which have flattened across the country and made some projects unnecessary; (d) general customer pushback against rising costs; and (e) how best to reflect reliability benefits.

The five issues we include in this chapter are challenging and reasonable people may disagree. Our purpose is to make sure the Board is informed with thoughtful intelligence on these matters from both sides. Our work in this Report complements, to some degree, the work of SPP's engineering staff to study the direct economic benefits of transmission that SPP has built in previous years, in terms of lower electricity costs for customers.[284]

B. Issues Challenging Transmission Planners

1. Decentralized Technologies: An Alternative to System Power?

Decentralized technologies can impact transmission plans in two ways. First, as we noted in last year's Report, transmission planners that do not incorporate increases in distributed generation in their transmission planning process risk overbuilding the grid with unneeded transmission projects, according to Synapse Energy Economics.[285] Second, decentralized technologies can potentially be a competitive alternative to transmission expansion projects and, thereby, reduce the need for such projects. Decentralized technologies can help keep power off of the system, by (a) generating it locally (via distributed generation resources), (b) allowing a customer to isolate itself from the grid (via a microgrid), or (c) by not consuming power (via conservation, energy efficiency, or demand response). It is this second impact we focus on in this chapter.

Is decentralized power a true, competitive alternative to system power, analogous to wireless telecommunications competing against traditional landline telecommunications? There is what we would term "intelligent chatter" from credible voices suggesting it may be. Accenture, for example, suggests that decentralized technologies will continue to grow and negatively impact utilities' sales. Accenture states: "Continued growth of distributed energy resources and energy efficiency measures could cause significant demand disruption and drive down utilities' revenues by up to $48 billion a year in the U.S. and €61 billion a year in Europe by 2025."[286] (For context, according to data from the EIA, utility revenues in the U.S. were approximately $315 billion in 2013,[287] so a reduction of $48 billion would approximately a 15 percent reduction in revenues.) Another source is a chairman emeritus from The Brattle Group, who asks: "What kind of industry would invest $1 trillion or $2 trillion simply to sell less and less of its products as its customers took control, and made more of their own energy, and other

[284] SPP personnel explained this ongoing report to us on a recent phone call.
[285] 2014 Looking Forward Report, 44, citing Sarah Jackson et al., *Forecasting Distributed Generation Resources in New England: Distributed Generation Must be Properly Accounted for in Regional System Planning*, Synapse Energy Economics, Inc., June 7, 2013, 1.
[286] Accenture, "Utilities Face Significant Revenue Losses from Growth of Solar, Storage and Energy Efficiency, Accenture Research Shows," December 8, 2014.
[287] EIA, "Electric Sales, Revenue, and Average Price, Table 10," with data for 2013, February 19, 2015, available at http://www.eia.gov/electricity/sales_revenue_price/.

companies grabbed a larger and larger share of the value chain?"[288] He concludes that utilities are on a "train wreck" path.[289]

In addition, there is substantial anecdotal evidence of decentralized investment. Regarding microgrids, we note that: (a) the U.S. DOE has granted approximately $8 million for seven microgrid projects across the U.S.;[290] (b) Twentynine Palms and other military bases are investing in microgrids for weather, physical and cyber security reasons, and saving up to $10 million per year in energy costs;[291] (c) NRG has teamed up with Green Mountain Power in Vermont to build a microgrid for the town of Rutland, Vermont, with the goal of "largely" taking the town off the grid;[292] and (e) the Princeton University microgrid, which we highlighted in last year's Report,[293] reportedly performed seamlessly during the 2014 polar vortex, operating on fuel oil for 36 straight hours before seamlessly switching back to grid power when system conditions had improved.[294]

Regarding the distributed generation technology using rooftop solar PV installations, its growth in the U.S. continues. According to the American Public Power Association, there is approximately 6.4 GW of distributed rooftop solar PV installed in the U.S. today, and that number is expected to grow to 9 GW by 2016 and up to 20 GW by 2020.[295] Michigan State University researchers, meanwhile, have developed a transparent solar cell that can be placed over windows for homes, commercial buildings, and any other surface with a clear surface.[296]

Regarding electricity storage, which can be decentralized and also part of a microgrid, Citi estimates that the global market for energy storage investment could be as high as $400 billion for 240 GW, excluding car batteries.[297] Several storage projects are in place in organized markets across the U.S., including the 64 MW AES Laurel Mountain integrated battery-based project in West Virginia (which is integrated with a 98 MW wind farm)[298] and a 3 MW PJM

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[288] Peter Behr, "Power Industry on a 'train wreck path,' consultant says," EnergyWire, September 4, 2014 (Behr Article).
[289] Behr Article.
[290] U.S. DOE, "Energy Department Announces $8 Million to Improve Resiliency of the Grid," September 8, 2014, available at http://www.energy.gov/articles/energy-department-announces-8-million-improve-resiliency-grid.
[291] Rebecca Smith, "Hacker, Terrorist Threats Spur Bases to Build Power Grids," Wall Street Journal, October 21, 2014.
[292] Colin Sullivan, "NRG, Green Mountain team up to design 'energy city of the future,'" EnergyWire, September 4, 2014.
[293] 2014 Looking Forward Report, 49.
[294] As recalled from John Webster, ICETEC Energy Services, "2014 Northeast Energy Summit," Omni Parker House Hotel, Boston, Massachusetts, September 18, 2014.
[295] American Public Power Association, "Distributed Generation," February 2015, available at http://publicpower.org/files/PDFs/23%20Distributed%20Generation.pdf.
[296] Michigan State University, "Solar Energy That Doesn't Block the View," August 19, 2014, available at http://msutoday.msu.edu/news/2014/solar-energy-that-doesnt-block-the-view/.
[297] Citi Research, "Energy Darwinism II, Energy Storage: Game Changer for Utilities, Tech, & Commodities," September 25, 2014.
[298] AES Energy Storage, "AES Marks Energy Storage Milestone with 400,000 MW-h of PJM Service from Laurel Mountain," April 11, 2013, available at http://www.aesenergystorage.com/2013/04/11/aes-marks-energy-storage-milestone-with-400000-mw-h-of-pjm-service-from-laurel-mountain/.

regulation ancillary services battery demonstration project at the East Penn Manufacturing facility,[299] which is part of the U.S. DOE's Smart Grid Storage Demonstration Program.[300]

While there is intelligent chatter about progress with decentralized technologies, there also are credible sources of pushback against the effectiveness of decentralized technologies, especially in displacing grid services. London Economics, in a recent report looking at decentralized technologies' role and participation in the transmission planning process,[301] found that decentralized technologies "are increasingly being put forth as possible solutions in lieu of transmission infrastructure."[302] However, according to London Economics, decentralized technologies "are rarely a complete substitute to transmission."[303] For example, London Economics concludes that decentralized technologies (a) often have "shorter economic lives" than transmission, (b) may "provide benefits to a smaller or more localized geographical segment of customers" than transmission, or (c) may only be able to provide partial services compared with transmission, which can provide the full suite of energy, capacity, and ancillary services on a continuous basis.[304]

Another recent article, co-authored by the Executive Director of the Harvard Electricity Policy Group and published in The Electricity Journal,[305] argues that distributed solar generation "is the most expensive form of renewable generation that is widely used today"[306] that has been the beneficiary of pricing mechanisms, such as net metering, that "overvalues both the energy and capacity of solar [distributed generation], imposes cross-subsidies on non-solar residential customers, and is socially regressive because it effectively transfers wealth from less affluent to more affluent customers."[307] The authors state that distributed solar generation "has energy value, the potential for reducing some transmission costs, and…some capacity value" as well as "positive environmental value," and "ought to be compensated accordingly."[308] To that point, the authors argue that policy and pricing matter for properly valuing distributed solar, and that certain incentive-based pricing policies, including net metering, "severely diminish" distributed solar's value and renders it "not a cost-effective means of reducing carbon emissions."[309]

Additionally, in a recent speech, Terry Boston, CEO of PJM, made the point that decentralized technologies may have a difficult time meeting the same standard of reliability as the grid.[310] He noted that during Superstorm Sandy, 50 percent of the distributed generation

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[299] East Penn Manufacturing Co, "12 Month Technical Performance Report, Grid-Scale Energy Storage Demonstration of Ancillary Services Using the UltraBattery Technology," January 21, 2014, 4-5.
[300] Ibid., 4.
[301] Julia Frayer, Eva Wang, London Economics International LLC, "A WIRES Report on Market Resource Alternatives: An Examination of New Technologies in the Electric Transmission Planning Process," on behalf of the Working Group for Investment in Reliable and Economic Electric Systems (WIRES), October 2014 (London Economics Report).
[302] London Economics Report, 8.
[303] London Economics Report, 8.
[304] London Economics Report, 12-13.
[305] Ashley Brown, Jillian Bunyan, "Valuation of Distributed Solar: A Qualitative View," *The Electricity Journal*, Volume 27, Issue 10, December 2014 (HEPG Distributed Solar Article).
[306] HEPG Distributed Solar Article, 34.
[307] HEPG Distributed Solar Article, 27.
[308] HEPG Distributed Solar Article, 48.
[309] HEPG Distributed Solar Article, 48.
[310] Boston NASEO Presentation.

units installed at New York City's hospitals failed at some point during the three days of the storm's aftermath.[311] He explained that just adding distributed generation to various points of the distribution grid is not sufficient; such units require regular maintenance, just like system generation resources. Boston also noted the complexity, precision, and quality of the bulk grid and its importance in discussing alternatives to grid service, and said that in discussing decentralized alternatives, the quality of service such resources can provide matters.[312]

One final point related to decentralized technologies is that they can be dependent on public policy. Like wind resources (which have been driven by state RPS standards and the PTC) and efficiency gains (driven by federal mandates on new products), decentralized technologies can be reliant on public policy in the form of money and mandates. One example of public policy driving investment in decentralized technologies is subsidies for microgrids, which can be very expensive on their own: the Princeton University microgrid cost approximately $100 million.[313] Subsidies, such as those from the U.S. DOE highlighted above, may help defray costs. A second example is net metering; 44 states plus the District of Columbia employ net metering standards[314] (See Figure 7.1, below), which require utilities to give credit to customers for energy generated behind the retail meter, often paying retail prices for customer generation in excess of the customer's own use that is delivered to the utility.[315] Policies such as these help drive the growth of decentralized technologies, but such public policies can also be fickle and uncertain. For example, Hawaii Electric Company recently proposed to end its net metering program, replacing it with an alternative tariff structure that would substantially cut compensation to distributed customers,[316] while other states, including Arizona[317] and Oklahoma,[318] are considering (or have adopted) new fees for distributed generation customers, which require customers with distributed generation to pay a fee to utilities.

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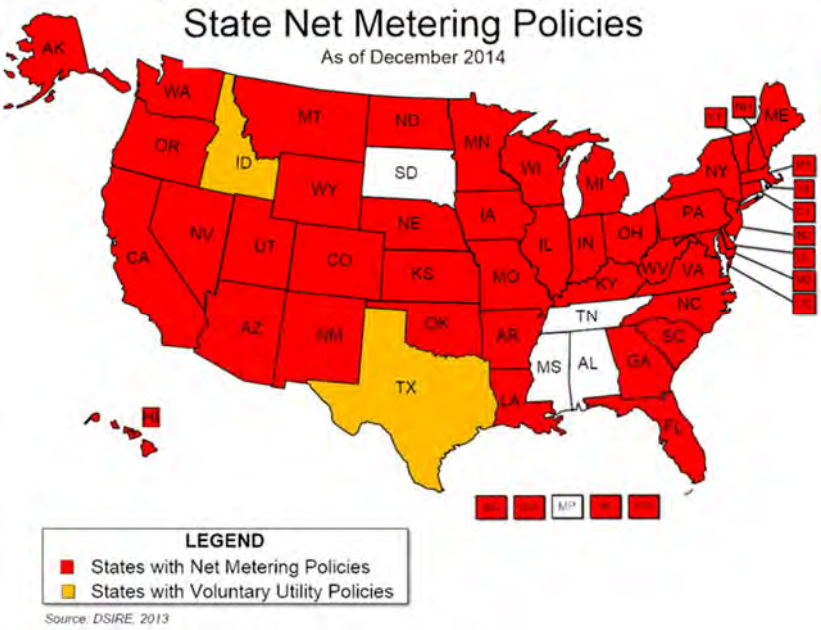
[311] Boston NASEO Presentation. See also, generally, "A Stronger, More Resilient New York," June 11, 2013, 107.
[312] As recalled from Boston NASEO Presentation.
[313] 2014 Looking Forward Report, 49.
[314] National Conference of State Legislatures, "Net Metering: Policy Overview and State Legislative Updates," updated December 18, 2014, available at http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx.
[315] 2014 Looking Forward Report, 50 to 51.
[316] Herman Trabish, "Hawaiian Electric's plan to end solar net metering, explained," Utility Dive, January 26, 2015, available at http://www.utilitydive.com/news/hawaiian-electrics-plan-to-end-solar-net-metering-explained/356432/.
[317] 2014 Looking Forward Report, 5.
[318] Herman Trabish, "Oklahoma Gas & Electric considers new charge for distributed generation," Utility Dive, November 3, 2014, available at http://www.utilitydive.com/news/oklahoma-gas-electric-considers-new-charge-for-distributed-generation/328739/.

Figure 7.1. State Net Metering Policies[319]



Source: National Conference of State Legislatures

In summary, at least four principles are suggested to guide this discussion of decentralized technologies and their potential impact on transmission planning. First, if considering decentralized solutions as a competitive alternative to system power and transmission expansion, comparability of service matters, as noted by PJM CEO Terry Boston.[320] It remains to be seen if decentralized technologies can achieve the same level of reliability as the grid, and at what cost. Second, in assessing decentralized technologies, consider combinations of decentralized solutions, not just each option on its own. This may help overcome the limitations of decentralized options on their own, as noted by London Economics in its Report. Third, it may help to recognize decentralized technologies' dependence on public policy, which can be fickle. Experience with net metering helps illustrate this point. Fourth, it may help to consider existing decentralized resources (e.g., distributed generation) when forecasting load in planning new transmission investments. In 2013, Synapse Energy Economics issued a report warning ISO New England – which Synapse notes could reach 2,855 MW of distributed generation by 2021[321] – of that risk, stating that ISO New England does not incorporate increases in distributed generation in its transmission planning process, and as a result, will over estimate its load forecasts and overbuild the transmission system with unneeded projects.[322]

[319] National Conference of State Legislatures, "Net Metering: Policy Overview and State Legislative Updates," updated December 18, 2014, available at http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx.
[320] Boston NASEO Presentation.
[321] Sarah Jackson et al., "Forecasting Distributed Generation Resources in New England: Distributed Generation Must be Properly Accounted for in Regional System Planning," Synapse Energy Economics, Inc., June 7, 2013 (Synapse ISO New England Report), 2.
[322] Synapse ISO New England Report, 1.

2. Exports of Renewables

A second issue currently challenging transmission planners involves the accommodation of new renewable resources, especially those that are meant for export to other control areas. The simple fact is that wind and solar resources are often located far from load centers, so developing sufficient transmission is essential to moving renewable power to where it is demanded.[323] As a result, new renewable resources often require new transmission investments. The challenge for transmission planners is to match cost allocation to beneficiaries, especially when it comes to exports. For example, we have heard concerns of internal customers who are allocated transmission costs for projects that help to deliver wind exports to another region.[324] With renewable resource investment expected to continue to grow in SPP and elsewhere, this is an issue that may challenge SPP for the foreseeable future.

Some might say that transmission projects (and their costs) that support wind power generated and consumed in the SPP footprint – even if the wind power is consumed in a different SPP state than that in which it was generated – will (a) be appropriately considered under the existing SPP ITP process and Highway-Byway cost allocation mechanism and (b) has the potential to lower market prices for all SPP customers. That is, they might reason that electrons disregard state borders and can thus produce economic benefits across the SPP footprint.

For exports of wind power outside the SPP footprint, however, it may be said by some that planning and cost allocation issues become more difficult and complex with such exports. These are fair questions to ask. Does transmission investment to support such export transactions yield benefits that accrue to internal SPP load? Are exporters of SPP wind (and the importing buyers in another control area) being allocated their fair share of transmission upgrades and firm transmission service costs through the interconnection process and through paying for firm transmission service? Would issues of planning and cost allocation for projects that support exports be best handled through interregional planning processes with other control areas, so that projects may be planned and the costs shared according to the benefits that accrue to each area (i.e., to SPP and to the importing control area)?

One way to bypass the complexities of grid expansion projects to support SPP wind power exports is through the use of HVDC transmission, an option generally advocated by PJM CEO Terry Boston[325] and by MISO in a recent presentation on a HVDC "network."[326] HVDC projects – while expensive and difficult to develop and build – offer benefits over AC solutions, including a simpler cost allocation, the ability to move power over long distances, fewer concerns about parallel flows on other systems, and a risk profile that requires a merchant developer to shoulder the market risk of the project.

3. Load Forecasts

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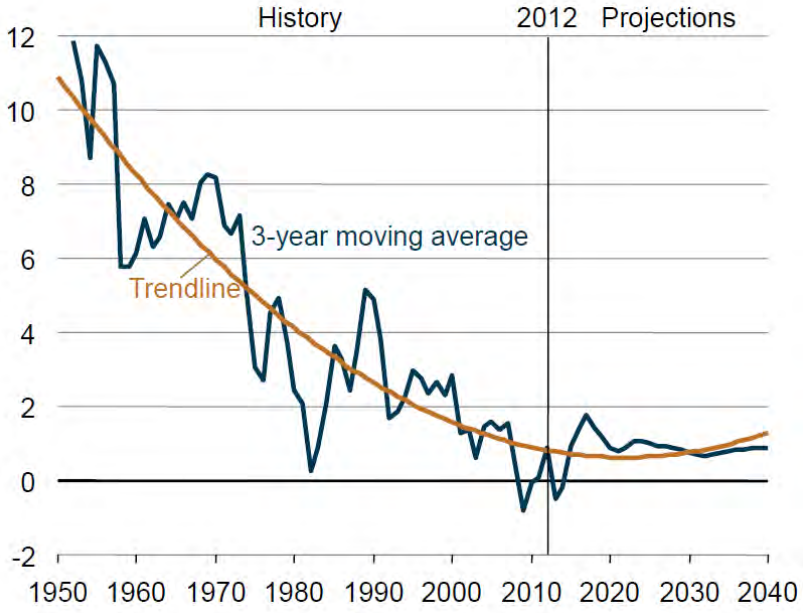
[323] International Electrotechnical Commission, "Grid integration of large-capacity Renewable Energy sources and use of large-capacity Electrical Energy Storage," 28, available at http://www.iec.ch/whitepaper/pdf/iecWP-gridintegrationlargecapacity-LR-en.pdf.
[324] RTO Insider Article.
[325] Boston NASEO Presentation, 25.
[326] MISO, "HVDC Network Concept," January 7, 2014. MISO estimates up to $50 billion in estimate potential value from a network of HVDC projects across the U.S. and Canada.

A third issue challenging transmission planners is load forecasting. Load forecasts are one of the most important variables in a transmission plan, as load growth often causes or speeds up the need for new transmission to maintain reliability. The challenge for transmission planners is getting the forecast to be reasonably accurate. A load forecast that is too high could result in overbuilding the grid, while load forecasts that are too low could delay or prevent needed transmission investment to maintain reliability.

We have seen concerns that transmission planners' forecasts – or those by its members – may be too high, leading to overinvestment in transmission.[327] SPP's most recent experience highlights how uncertain load forecasts can be and how important they are to transmission plans. SPP's membership recently recommended that the Board withdraw its approval for SWEPCO's $116 million Kings River-Shipe Road 345-kV line in northwest Arkansas because of a "50% drop in load growth rates in the area critical to the project's need."[328] Soon thereafter, SWEPCO announced it would no longer pursue building the line. Load projections are inherently uncertain, and as we noted in the 2013 Looking Forward Report, there is a "potential for slow, stagnant, or even declining electricity consumption."[329] The 2014 EIA Annual Energy Outlook continues to support the view that demand growth is likely to be modest going forward. As shown in Figure 7.2 below, the trend has been downward for decades; EIA's projection for demand growth is just 0.9 percent annually from 2012 through 2040.

Figure 7.2. Historical and Forecasted U.S. Electricity Demand Growth Rates in EIA's 2014 Annual Energy Outlook Reference Case (percent)



Source: EIA Annual Energy Outlook 2014, Figure MT-29, p. MT-16

Importantly, too, load growth and load forecasts can vary significantly by region and by utility. For example, some have noted that portions of SPP's load forecasts are driven by the

[327] RTO Insider Article.
[328] RTO Insider Article.
[329] Deloitte, *The Math Does Not Lie: Factoring the future of the U.S. electric power industry*, Deloitte Center for Energy Solutions, October 22, 2012, 1.

outlook for natural gas and oil production operations.[330] For such areas, changes in forecasts for gas and oil production activity could have a substantial impact on load forecasts, potentially adding a premium to the importance of regularly updating (and sharing) load forecasts for SPP member load serving entities. Even with such updates, load forecasts are inherently uncertain; this suggests at least the use of sensitivity analyses on load when the Board considers proposals for new transmission investments.

4. General Customer Pushback Against Paying for Transmission

Beyond the specifics of the first three issues identified above – potential competition from decentralized technologies, projects to support exports of renewables, and load forecasting – there also exists the potential for general pushback by customers against paying for additional transmission investments. Any discomfort among SPP customers and members would not be unique, as we have seen examples elsewhere of customer reluctance to pay for transmission expansion.

One example comes from PSE&G in New Jersey, where, following the impacts of Superstorm Sandy, the utility developed its voluntary "Energy Strong" proposal to strengthen its electric and gas systems against severe weather conditions.[331] Superstorm Sandy had a substantial impact on the greater PSE&G area; the average outage for an affected customer was 3.5 days,[332] and a macroeconomic analysis conducted by the Edward J. Bloustein School of Planning and Public Policy at Rutgers University found that "Superstorm Sandy was responsible for roughly $12 billion in lost economic activity, 7,300 job losses, significantly lower tax revenues and higher governmental costs in 2012 alone."[333] PSE&G developed its Energy Strong proposal to "mitigated outages to electric and gas service that would otherwise occur as a result of major weather events,"[334] and hired The Brattle Group to conduct an analysis that estimates the benefits that may be realized from PSE&G's proposed investments. Those investments totaled $3.9 billion over a ten year period, $2.8 billion of which is associated with investments in the electric system.[335] The Brattle Group provided a "conservative" estimate that PSE&G's Energy Strong program's electric grid investments would provide benefits to customers "resulting from mitigated outages over the course of a three day outage of $1.92 billion"[336] and that "the cumulative duration of outages necessary" to break even on PSE&G's $2.8 billion investment would be approximately 3.08 days.[337]

Despite both these findings by Brattle in its PSE&G Report, and Rutgers' $12 billion in estimated lost economic activity as a result of Superstorm Sandy, some parties pushed back

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[330] RTO Insider Article.
[331] "PSE&G Reaches $1.22 Billion Settlement in Energy Strong Proceeding," Transmission & Distribution World Magazine, May 7, 2014 (T&D Article), available at http://tdworld.com/distribution/pseg-reaches-122-billion-settlement-energy-strong-proceeding.
[332] Peter Fox-Penner, William Zarakas, "Analysis of Benefits: PS&EG's Energy Strong Program," The Brattle Group, October 7, 2013, (Brattle PSE&G Study), xi.
[333] Brattle PSE&G Study, vii.
[334] Brattle PSE&G Report, vi.
[335] Brattle PSE&G Report, viii.
[336] Brattle PSE&G Report, xi.
[337] Brattle PSE&G Report, xi.

against the proposed spending, including groups representing ratepayers.[338] While some pushback was against assumptions made in the Brattle PSE&G Report, others claimed that the upgrades were too expensive for the average consumer and argued for a less costly and more focused upgrade effort.[339] PSE&G eventually settled with all parties on a scaled-back package of investments of $1.22 billion, less than $1 billion of which will go to electric system investments.[340] Importantly, to see the full context, note that PSE&G's ratepayers have seen large increases in their transmission rates in recent years for other reasons – transmission rates are up almost 159 percent in 2015 when compared to transmission rates in 2012.[341] Transmission rates have climbed high enough to be comparable to capacity costs in PJM's capacity market; the most recent base residual auction (for the 2017-2018 delivery period) yielded a localized price of $215/MW-day for PSE&G,[342] while PSE&G's most recent transmission charge for its share of transmission expansion projects in PJM totaled $199.15/MW-day.[343]

Another example of customer attitudes toward paying for additional transmission investment comes from General Electric's Digital Energy group, which in 2014 released the results of its Grid Resiliency Survey "measuring the U.S. public's current perception of the power grid, its experiences and its future expectations."[344] The survey was conducted in May and June of 2014, shortly following a "very active 2014 winter storm season that led to several power outages, impacting millions of Americans."[345] The GE Grid Survey found that just 38 percent of U.S. adults aged 18 and over are "willing to pay an additional $10 per month to ensure the grid is more reliable."[346] To account for differences among consumers that have experienced more recent outages than others, the GE Grid Survey separated its results by those living east of the Mississippi River and those living west of the Mississippi, noting that "consumers living east of the Mississippi experienced nearly three times as many power outages on average than those living west of the Mississippi."[347] Still, the GE Grid Survey found that just 41 percent of customers living east of the Mississippi River and 34 percent of customers living west of the Mississippi are "willing to pay an additional $10 per month to ensure the grid is more reliable."[348]

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[338] "Opponents of PSEG Grid Hardening Plan Dismiss Brattle Group Study," Transmission & Distribution World Magazine, December 16, 2013 (T&D Opposition Article), available at http://tdworld.com/bet-you-haven039t-seen/opponents-pseg-grid-hardening-plan-dismiss-brattle-group-study.
[339] T&D Opposition Article.
[340] T&D Article.
[341] PSE&G's most recent rate for firm transmission service was $199.15/MW-day; the rate in 2012 was $76.94/MW-day.
[342] PJM Interconnection, LLC, "2017/2018 Base Residual Auction Results," available at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx.
[343] "Announcement: Rates for Firm Transmission Service," bgs-auction.com, January 6, 2014, available at http://bgs-auction.com/bgs.press.annc.item.asp?anncId=472.
[344] GE Digital Energy, "Grid Resiliency Survey," August 14, 2014 (GE Grid Survey), available at http://www.gedigitalenergy.com/gegridsurvey/#Infographic.
[345] GE Grid Survey.
[346] GE Grid Survey.
[347] GE Grid Survey.
[348] GE Grid Survey.

5. Estimating Reliability Benefits of Avoidance of Outages, Grid Security Enhancements

Transmission investment can lower the cost of electricity to customers through reductions in fuel costs. (The SPP engineering group's ongoing study of the benefits of transmission is seeking to measure this benefit.) Transmission investment can also increase system reliability. Estimating the value of reliability benefits can be done through the use of metrics that seek to measure the economic value from avoiding outages. As noted below, SPP uses these metrics in its analysis of transmission investments. Estimates of the value of reliability benefits can vary widely; we explore some studies of the value of reliability benefits below.

Reliability, at its core, is about keeping the electricity flowing to customers. Because customers do not use electricity as an end in itself, but rather as a means to run industrial processes and keep the lights on at their businesses, schools, hospitals, and homes, outages have real economic consequences for customers and the overall economy. Between 2003 and 2012, an estimated 679 widespread power outages occurred due to severe weather alone.[349] The costs of such outages can be significant, estimated to cost the U.S. between $20 billion and $150 billion annually.[350] The November 1965 blackout in the northeastern U.S. and Canada impacted roughly 30 million people and had initial estimates of economic losses of $100 million in 1965 dollars;[351] adjusted for inflation, that figure is approximately $750 million today. The August 2003 blackout in the northeastern U.S. and Canada impacted approximately 50 million people and resulted in an estimated $4 billion to $10 billion in economic damage.[352] More recently, the September 2011 blackout that impacted parts of southern California, Arizona, and Mexico resulted in economic losses of approximately $100 million.[353] And, as noted earlier in this chapter, "Superstorm Sandy was responsible for roughly $12 billion in lost economic activity, 7,300 job losses, significantly lower tax revenues and higher governmental costs in 2012 alone."[354] The costs of these outages include "lost output and wages, spoiled inventory, delayed production, inconvenience and damage to the electric grid."[355]

Since outages have costs, and reliability enhancing-transmission investment can mitigate the frequency and duration of outages, then it should be possible to estimate the economic benefits of such transmission investments. Indeed, the "value of lost load," or VOLL, is the traditional metric by which "the value that customers place on mitigating power outages" is

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[349] Executive Office of the President, "Economic Benefits of Increasing Electric Grid Resilience to Weather Outages," August 2013 (President's Reliability Report), 3.
[350] Johannes Pfeifenberger, "Reliability and Economics: Separate Realities or Part of the Same Continuum?," The Brattle Group, Presented to the Harvard Electricity Policy Group, December 1, 2011 (Pfeifenberger Presentation), 2.
[351] Federal Power Commission, "Report to the President by the Federal Power Commission on the Power Failure in the Northeastern United States and the Province of Ontario on November 9-10, 1965," December 6, 1965, (1965 FPC Report) available at http://blackout.gmu.edu/archive/pdf/fpc_65.pdf., 40.
[352] Matt Egan, "10 Years Later: Could An Epic Blackout Happen Again?," Fox Business, August 15, 2013, available at http://www.foxbusiness.com/government/2013/08/15/10-years-later-could-epic-blackout-happen-again/.
[353] Don Jergler, "Southwest Power Outage Economic Cost Put At $100M," Insurance Journal, September 13, 2011, available at http://www.insurancejournal.com/news/west/2011/09/13/215102.htm.
[354] Brattle PSE&G Study, vii.
[355] President's Reliability Report, 3.

measured.[356] VOLLs "represent the values to customers of avoiding the loss of power; that is, estimates of the economic damages that they would realize as a result of a power outage."[357]

VOLLs vary by customer class and can vary across estimates. As noted by The Brattle Group:

> Estimating the VOLL is largely a survey-based process through which utility customers value the economic impacts that varying levels of outages have upon their households and/or businesses. Accordingly, VOLLs need to be estimated separately for the various customer classes, because the impact of an outage can differ significantly among residential customers (who are inconvenienced by an outage and, if the outage duration is long enough, will incur out-of-pocket costs) and commercial and industrial customers (for which a loss of power will likely have an impact on production processes, result in a loss of sales and revenue and/or involve out-of-pocket costs). The accuracy of the VOLL estimate depends upon the quality of the survey methodology, instrument and procedure. Thus, estimates of VOLLs are an informative but non-perfect measure of service value.[358]

Brattle Group, for its part, has estimated VOLLs for residential customers to be between $1,500/MWh and $3,000/MWh (in $2006) and well in excess of $10,000/MWh for commercial and industrial customers (in $2006).[359]

Once estimated, VOLLs can then be used to quantify some portion of the reliability benefits that would accrue as a result of investments in new transmission to buttress reliability. For example, The Brattle Group's aforementioned study of PSE&G's Energy Strong proposal estimated $1.92 billion in reliability benefits (mitigating outages and the associated economic losses) based on its estimation of VOLLs across PSE&G customer classes.[360] SPP, for its part, also uses estimates of VOLL in its estimates of transmission investment benefits which is taken from "existing studies and literature."[361] SPP determines the total reduction in outage hours expected to result from the proposed transmission investment and multiplies that amount by the VOLL, producing the total expected monetary benefit related to reliability from that project.[362]

Another consideration regarding the reliability benefits of transmission investments involves grid security, both physical and cyber. As we point out in chapter 5, enhancing grid security may be less about preventing the next attack – i.e., bulletproofing transformers against physical threats – and more about making the grid more resilient so as to mitigate the impact of such attacks. Additional investment in the grid can deliver such resiliency benefits and may be considered in a transmission valuation framework. One challenge may be to account for the changing risk to the grid related to outages caused by physical or cyber-attacks. Historical outage data, for example, may only include weather-driven outages and other forced outages, not necessarily capturing the risk of outages caused by physical or cyber-attacks.

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[356] Brattle PSE&G Study, x.
[357] Brattle PSE&G Study, x.
[358] Brattle PSE&G Study, 13-14.
[359] Pfeifenberger Presentation, 3.
[360] Brattle PSE&G Report, xi.
[361] Southwest Power Pool Metrics Task Force, "Benefits for the 2013 Regional Cost Allocation Review," July 5, 2012, section 6.2.2.
[362] Ibid.

It is also worth noting that while transmission planners can estimate the costs and benefits of transmission solutions, including reliability benefits, such analyses do not demonstrate transmission's cost effectiveness compared to alternative solutions – i.e., non-transmission alternatives, such as decentralized technologies. Some say that the grid may not be the only option in providing reliable service, especially as technological capabilities change over time. In addition, non-transmission alternatives and decentralized solutions may not be subject to the same vulnerabilities as the transmission system, such as outages from severe weather.

VIII. Smart Grid

A. Introduction

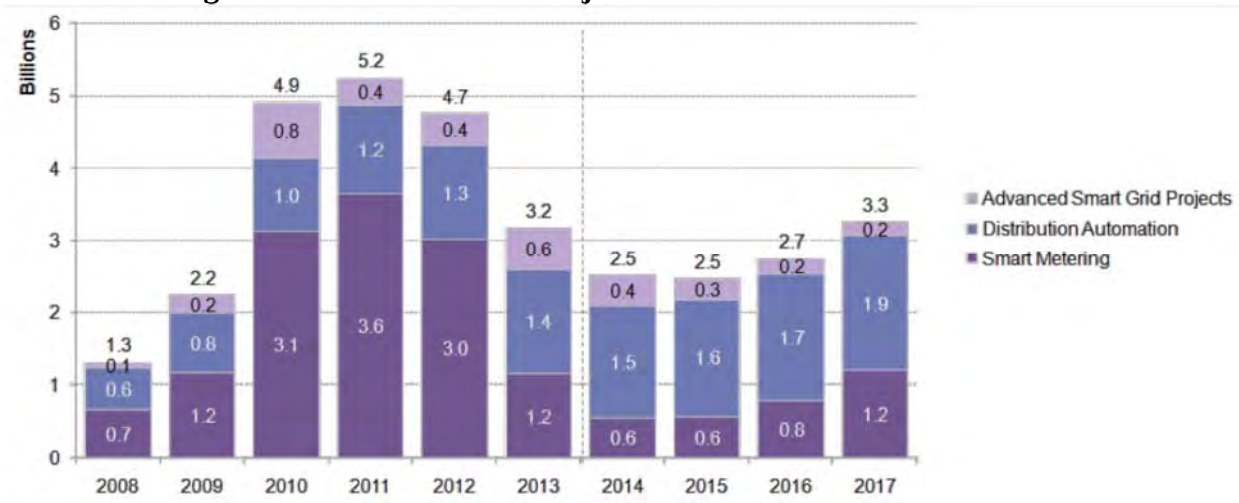
According to the Department of Energy's 2014 Smart Grid System Report, the electricity industry spent $18 billion on smart grid technologies from 2010 to 2013.[363] Nearly half of that amount came from investments made under the American Recovery and Reinvestment Act of 2009 (ARRA), totaling about $8 billion.[364] The ARRA investments were primarily made by utilities that received grants from the federal government. The U.S. DOE was tasked with overseeing those investments and its report describes the deployment of different technologies and their benefits. Herein, we explore the status of smart grid investment and technology, its impacts on the grid, and where the industry is headed.

[363] United States Department of Energy, *2014 Smart Grid System Report*, August 2014, 2.
[364] Ibid.

B. Technology, Benefits, and Costs

Because "smart grid" is a broad term, it is important to understand what it encompasses. Despite varying definitions, in general, "smart grid" refers to certain applications of technology that enhance the existing grid. The Pacific Northwest National Laboratory (PNNL) recently stated that "a smart grid uses digital technology to improve the reliability, security, flexibility, and efficiency of the electric system, from large generation through the delivery systems to electricity consumers and a growing number of distributed generation (DG) and storage resources."[365] There is a wide range of smart grid applications for different segments of the grid. These can include (a) digitally based equipment at high voltage substations to instantaneously monitor voltage, current, and frequency to better detect and react to disturbances, (b) devices that automatically locate and isolate faults at the distribution level, or (c) replacing older electric meters with more advanced meters with digital two-way communications that can increase the operational efficiency of utilities.[366] Figure 8.1 shows historical and projected investment for different smart grid technologies.[367]

Figure 8.1. Historical and Projected U.S. Smart Grid Investment



Source: U.S. Department of Energy, *2014 Smart Grid System Report*, August 2014, 3.

In recent years, the most popular application of smart grid technology has been the integration of advanced metering infrastructure (AMI), which includes smart meters.[368] Much of the growth in AMI has been due to ARRA funding which began in 2009. Under ARRA, the Smart Grid Investment Grant (SGIG) provided for joint cost sharing of smart grid projects whereby the federal government would financially support investments made by utilities.[369] There are a total of 99 SGIG projects with a combined budget of about $8 billion. The federal share is about $3.4 billion. Projects were chosen by a merit-based competitive solicitation.[370]

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[365] Pacific Northwest National Laboratory, *Smart Grid Status and Metrics Report*, July 2014, 1.1.
[366] United States Department of Energy, *2014 Smart Grid System Report*, August 2014, 4, 7, 9.
[367] Ibid., 3-4.
[368] Ibid., 2.
[369] United States Department of Energy, "Smart Grid Investment Program," Smartgrid.gov, accessed March 7, 2015, available at https://www.smartgrid.gov/recovery_act/overview/smart_grid_investment_grant_program.
[370] Ibid.

The key feature of smart meter technology is the capability to allow two-way communication between the utility and the customer. This provides several benefits. The primary benefit is that it can serve as a gateway for the transfer of detailed information as well as allow customers to have greater control over its energy usage when coupled with certain customer-based devices, such as intelligent thermostats and in-home displays.[371] The coupling of AMI and customer-based devices can increase the effectiveness of time-based rate programs, including time-of-use rates, critical peak pricing, variable peak pricing, etc., that encourage customers to adjust their consumption based on price.[372] If these programs are adopted by enough customers, it can have an impact on reducing peak electricity demand and thereby potentially defer new capacity needs.[373]

OG&E, a regulated utility in SPP's service territory, invested about $293 million in smart grid technologies with $130 million of that amount coming from SGIG funding.[374] As a part of its investment, it tested a pilot program for a new time-based rate over a two-year period which involved the participation of 4,670 customers. The new time-based rate provided prices that varied daily in order to cause a behavioral change in the participants' pattern of electricity consumption and a reduction in peak demand. The program resulted in a peak demand reduction of 1.8 kW per customer during critical events and an average reduction of 1.3 kW per customer during non-event peak periods. The average bill reduction during the summer was over $150 per customer. Due to the favorable results, OG&E stated that it would roll out the program to "20% of their customers (120,000) by 2016, with the aim of deferring investment in about 170 MW of power plant capacity."[375]

AMI also provides benefits that can enable enhanced operational capabilities and yield improvements in efficiencies. Some examples include (a) lower personnel and transportation costs due to remote meter reading, (b) improved outage management from meters that alert utilities when customers lose power, (c) improved billing and customer support, and (d) allowing measurement of two-way power flows for customers who have on-site generation.[376]

A recent U.S. DOE case study on Duke Energy's efforts in deploying smart grid technologies for its Ohio and Carolinas customers shows that its smart grid program has resulted in a range of operational efficiencies. In 2007, Duke initiated a 10-year smart grid program to chiefly deploy AMI and distribution technologies across the states it serves. In 2009, Duke received $200 million from ARRA funds, giving it a total budget of $555 million. With that money, it installed 966,000 smart meters in its Ohio and Carolinas territories and estimated that, over a 20-year period, benefits would amount to about $382.8 million on a net present value basis. Benefits were primarily derived from avoided operations and maintenance costs from

[371] United States Department of Energy, *2014 Smart Grid System Report*, August 2014, 4.
[372] Ibid., 5.
[373] Ibid., 6.
[374] United States Department of Energy, "Recovery Act Smart Grid Programs," Smartgrid.gov, accessed March 4, 2015, available at https://www.smartgrid.gov/recovery_act/project_information.
[375] United States Department of Energy, *Demand Response Defers Investment in New Power Plants in Oklahoma*, April 2013.
[376] United States Department of Energy, *2014 Smart Grid System Report*, August 2014, 4.

continuous voltage monitoring and remote meter reading. Currently, Duke is ahead of schedule in terms of meeting its benchmark estimate of benefits.[377]

According to the U.S. DOE, in 2013, there was approximately 46 million smart meters nationwide. The U.S. DOE expects that number to grow to 65 million in 2015 which would equal roughly 45 percent of total meters in use in 2013.[378] However, the growth in AMI has been concentrated. Nearly 75 percent of AMI installations to date have occurred in only 10 states and in the District of Columbia. The main contributing factors for such growth are a combination of "state legislative and regulatory requirements for AMI, ARRA funding, and by specific cost recovery mechanisms in certain regions."[379]

In terms of cost, according to the U.S. DOE, the cost per smart meter deployed generally has been between $120 and $240. These costs are calculated from the deployment costs of the AMI portion of a sample of nine utility smart grid projects that received total ARRA funding greater than $100 million. Some of the variations in costs per smart meter are a result of different customer class deployments, smart meter capabilities, and infrastructure requirements. Figure 8.2 below provides these costs per meter.[380]

Figure 8.2. Number of AMI Meters Installed and Associated Deployment Cost by Utility

Utility	States	AMI Meters Installed	Deployment Cost	Cost per Meter
Florida Power & Light Company	Florida	3,068,136	$373,231,325	$121.65
Duke Energy Business Services, LLC	Indiana, Kentucky, North Carolina, Ohio, South Carolina	1,062,169	$134,687,185	$126.80
PECO	Pennsylvania	784,253	$118,400,057	$150.97
CenterPoint Energy Houston Electric, LLC	Texas	2,130,737	$330,701,313	$155.21
Oklahoma Gas & Electric Company	Arkansas, Oklahoma	818,415	$153,693,666	$187.79
Potomac Electric Power Company	Maryland	552,982	$114,625,126	$207.29
Sacramento Municipal Utility District	California	617,502	$130,859,704	$211.92
Baltimore Gas and Electric Company	Maryland	575,081	$129,191,052	$224.65
Electric Power Board of Chattanooga	Georgia, Tennessee	175,116	$41,861,000	$239.05

Source: United States Department of Energy, smartgrid.gov, author's calculations.

As a point of comparison, another utility, Consolidated Edison, which was a recipient of ARRA funding but not for AMI,[381] recently filed a rate case with plans to roll out its "advanced metering initiative" over an eight-year period and spend $1.5 billion for smart electric and gas

[377] United States Department of Energy, *Integrated Smart Grid Provides Wide Range of Benefits in Ohio and the Carolinas*, September 2014, 3-5.
[378] United States Department of Energy, *2014 Smart Grid System Report*, August 2014, 4.
[379] Ibid.
[380] United States Department of Energy, "Recovery Act Smart Grid Programs," accessed March 4, 2015, available at https://www.smartgrid.gov/recovery_act/project_information?page=5&solrsort=is_arra_funding%20desc&f[0]=im_field_project_type%3A5164&f[1]=im_taxonomy_vocabulary_4%3A18.
[381] United States Department of Energy, "Recovery Act Smart Grid Programs," accessed March 4, 2015.

meters. The cost of each meter is estimated to be $270 with installation, about 13 percent higher than the high-end of the sampled range shown in Figure 8.2.[382]

Despite the cost data that is currently available, it is still too early to tell which direction costs will go. We would expect that as a technology matures that costs will decrease over time, but other factors can influence the cost such as state energy programs and regulations. It is also too early to determine the full amount of benefits as customer-based devices have not caught up with the growth in AMI.[383] Customer-based devices are necessary to effectively realize savings from time-based rate programs since they provide more awareness and control of energy usage for the user.[384]

C. Key Issues and Recommendations

ARRA funding provided significant support for the growth in smart grid technologies, and in particular for AMI over the past six years, but as the program winds down in 2015, there are questions about whether the industry will be able to maintain momentum. AMI is just one part of the smart grid. To fully implement smart grid, investment in other areas such as distribution automation and transmission system upgrades must also be made. The Electric Power Research Institute estimates that spending of $338 to $476 billion will be needed over a 20-year period across the country.[385] That would mean, without public money, the industry would have to spend, on average, $17 to $24 billion per year. Whether that is feasible will depend on many factors, but as we know from the wind energy industry, without federal subsidies, growth can come to a halt.

Furthermore, a fully functioning and efficient smart grid is all about the convergence of all parts of the grid through digital communications and control. Customer participation is essential and there are concerns. For example, technologies such as smart meters that serve as a gateway for two-way communications between the customer and the utility over a digital network, through connected customer-based devices, raise concerns about security and privacy. Among other factors, cybersecurity will be a critical issue in further customer adoption of smart grid in the future.[386] While cybersecurity is becoming more of a focus in the electricity industry, it already has received significant attention from well-documented cyber-attacks that have occurred in other industries and organizations such as banking, media, healthcare, and government. Over the past several years, the National Institute of Standards and Technology has been developing a comprehensive framework for organizations to create effective strategies for implementing smart grid cybersecurity. This is a notable step because it recognizes "that the electric grid is changing from a relatively closed system to a complex, highly interconnected

[382] Capital New York, "Con Ed spending $1.5 billion on 'smart meter' program," accessed March 4, 2015, available at http://www.capitalnewyork.com/article/city-hall/2015/02/8562149/con-ed-spending-15-billion-smart-meter-program.
[383] United States Department of Energy, *2014 Smart Grid System Report*, August 2014, 5.
[384] Ibid.
[385] Ibid., 3.
[386] Ibid., 11.

environment."[387] Still, no matter how much progress is made, it is likely that consumers who are concerned about such vulnerabilities may not fully adopt the customer-based technologies such as intelligent thermostats that would allow them to better participate in time-based rate programs and manage their energy usage.

As already noted, smart grid is defined as a way to "enhance the existing grid." It can actually help maintain the longevity of the centralized grid by making it more efficient, reliable, and resilient. Even though AMI is a downstream smart grid technology and may not have a direct impact to SPP, considering the growth that has taken place thus far, we recommend that the SPP Board continue to communicate with its members to: (a) see what type of efforts, if any, they have implemented with respect to smart grid and (b) if they have made such efforts, see how SPP can add value to its members' smart grid investments.

[387] United States Department of Commerce, National Institute of Standards and Technology, *Guidelines for Smart Grid Cybersecurity, Volume I – Smart Grid Cybersecurity Strategy, Architecture, and High-Level Requirements, NISTIR 7628 Revision 1,* September 2014, ix.

IX. Wind (and Solar) Exports From SPP's Footprint

SPP has been described as the "Saudi Arabia" of wind resources.[388] While SPP uses much of that wind energy internally – wind provided 11 percent of total generation in 2013 and provided as much as 33.4 percent of total SPP load on a single day in 2013[389] – it is natural to consider export possibilities to areas less rich in renewable resources. In this chapter, we explore that opportunity for exports, focusing particularly on sales to the southeast.

We begin by considering potential **supply** of wind and also solar resources in SPP. Next, we look at potential **demand** for SPP's wind and solar in other areas, especially the southeastern U.S. Then, we turn to **transport** of wind and solar exports, either through use and expansion of the existing AC grid or through use of HVDC projects. We conclude by noting SPP's potential role as a facilitator of export transactions. We consider SPP's value proposition in exporting its wind and solar resources, and we provide evidence that SPP has the supply to effectuate exports,

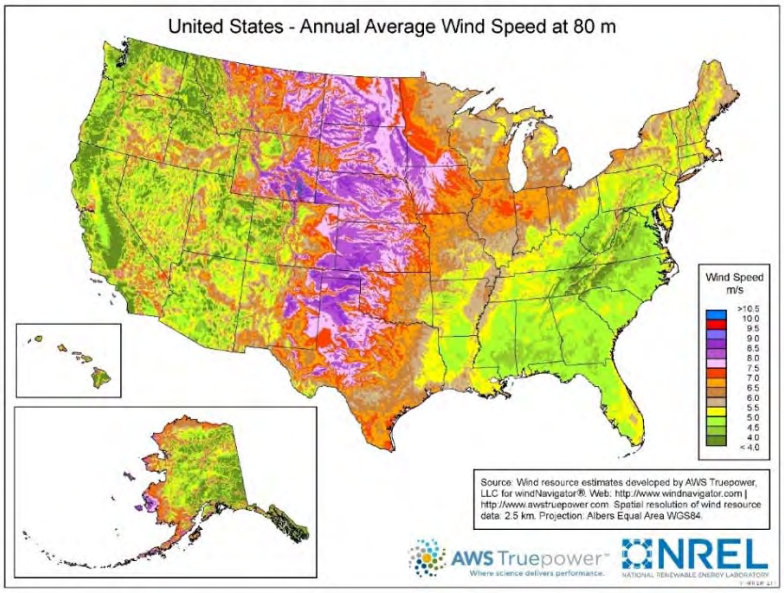
[388] Southwest Power Pool, "SPP 101," (SPP Presentation), 75, available at http://www.spp.org/publications/Intro_to_SPP.pdf.
[389] SPP 2013 State of the Market Report, 36.

but faces hurdles related to both demand and transport. We offer a potential next step for SPP's consideration.

A. Supply

SPP's renewable energy potential is enviable. Its geographic location has some of the best potential wind resources in the U.S., primarily from Oklahoma, Texas, Kansas, and Nebraska. In addition, there is significant solar potential, especially in eastern New Mexico. SPP has estimated its total wind potential in its footprint to be between 60,000 and 90,000 MW,[390] which is more energy than SPP uses during its peak demand.[391] Figure 9.1 below illustrates the unique abundance of SPP's wind resources, while Figure 9.2 shows U.S. solar PV potential.

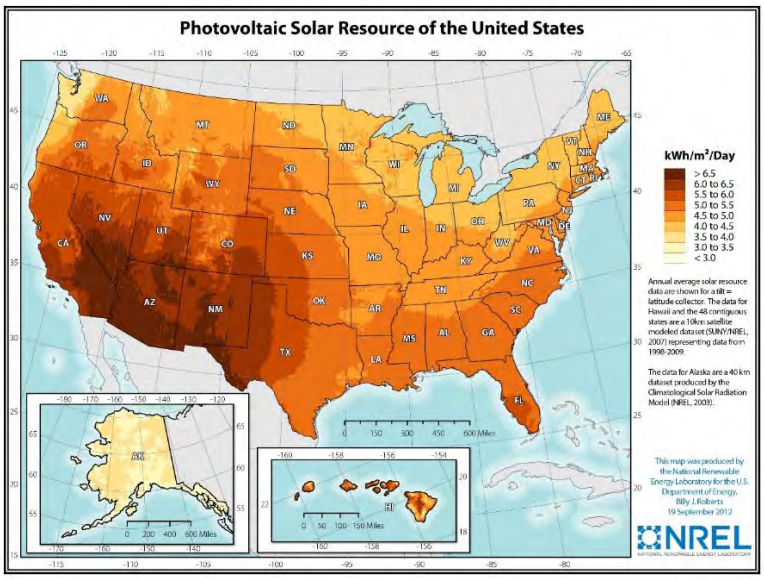
Figure 9.1. U.S. Annual Average Wind Speed[392]



Source: NREL

Figure 9.2. U.S. Solar PV Potential[393]

[390] SPP 101, 76.
[391] SPP 101, 76.
[392] National Renewable Energy Laboratory (NREL), available at http://www.nrel.gov/gis/images/80m_wind/USwind300dpe4-11.jpg.
[393] National Renewable Energy Laboratory (NREL), available at http://www.nrel.gov/gis/images/eere_pv/national_photovoltaic_2012-01.jpg.

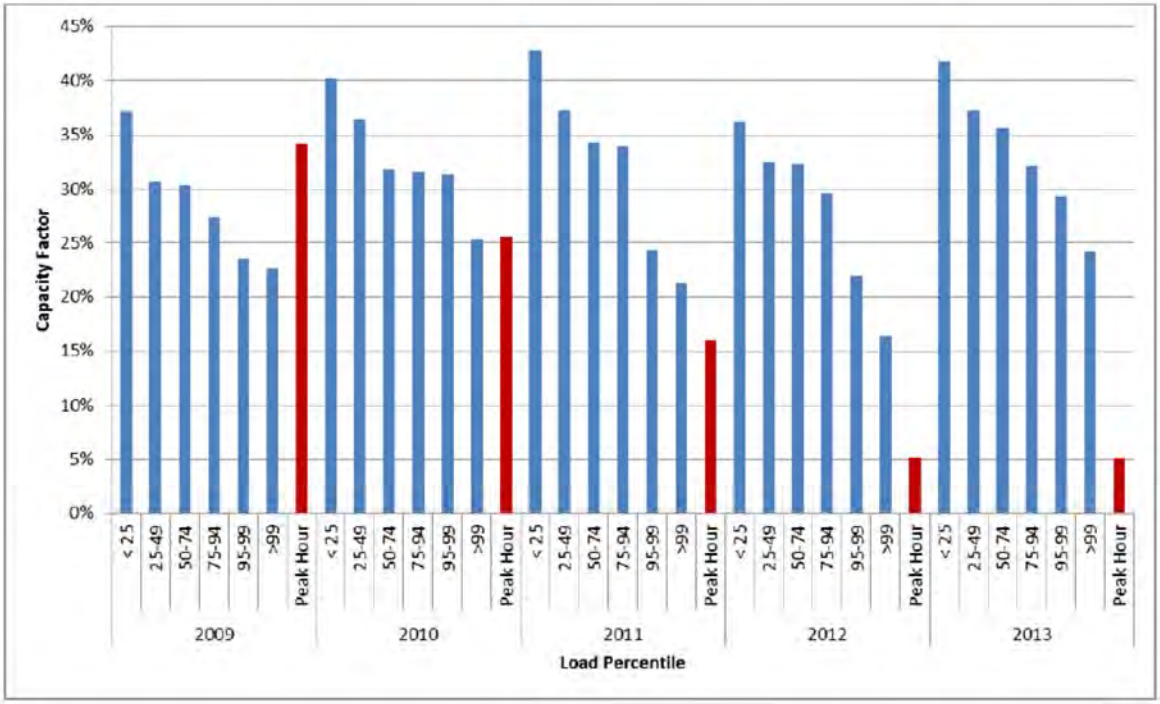


Source: NREL

SPP has realized a significant amount of wind generation. By the end of 2013, SPP had 8,405 MW of total registered wind capacity.[394] (According to conversations we have had with SPP personnel, that number has grown to approximately 9,200 MW.[395]) SPP also has over 19,000 MW of wind resources under development.[396] SPP's geographic location and recent technological improvements in the manufacturing of wind turbines has resulted in capacity factors approaching 45 percent.[397] Figure 9.3 shows the average wind capacity factor for the years 2009 through 2013 across all hours of each year separated by load percentile. The figure shows, for example, that in 2013, SPP wind resources had a capacity factor of over 40 percent in hours in which SPP load was in the lowest 25th percentile.

Figure 9.3. Wind Capacity Factor Compared to Load Percentiles 2009 - 2013[398]

[394] 2013 SPP State of the Market Report, 34.
[395] See also Comments of Jay Caspary, available at https://www.youtube.com/watch?v=JWXGGI1JrjU.
[396] SPP 101, 76. This figure includes wind in generation interconnection queue.
[397] 2013 SPP State of the Market Report, 35.
[398] 2013 SPP State of the Market Report, 35.



Source: 2013 SPP State of the Market Report, 35

SPP's solar potential has so far remained largely untapped, but that may soon change. Approximately 2,000 MW of solar resources – largely from New Mexico – have recently been added to the SPP interconnection queue.[399]

B. Demand

Turning to potential export demand for SPP's renewable resources, especially its wind, there are at least three potential drivers. First, and by far the most important, is public policy mandates for purchasing renewable energy, such as state renewable energy portfolio standards (RPS). Second is economics, which can also be driven by public policy through tax incentives and other financial subsidies provided to renewable developers to make their generation more cost competitive. Third is desire to diversify resource portfolios. We look at all three of these drivers in this section.

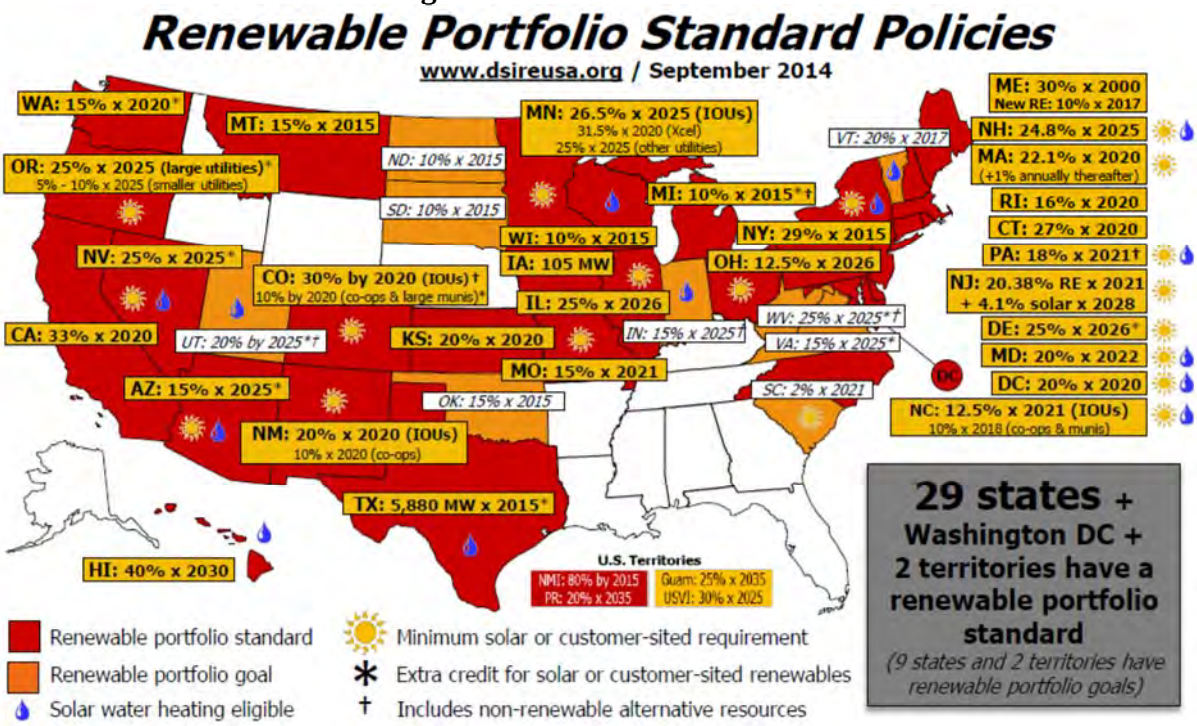
1. RPS Mandates

More than perhaps any other driver, state requirements for renewable energy purchases – through RPS mandates – matter considerably to assessing a state or region's demand for renewable energy. Twenty-nine states, plus the District of Columbia, have renewable portfolio standards; nine more have renewable portfolio goals. Focusing on southeastern U.S. states, only one state – North Carolina – has a renewable portfolio standard, and only one other – South

[399] Comments of Jay Caspary, available at https://www.youtube.com/watch?v=JWXGGI1JrjU.

Carolina – has a renewable portfolio goal.[400] The other southeastern states – Tennessee, Mississippi, Alabama, Georgia, and Florida – have no renewable portfolio standards or goals. Figure 9.4 below visually demonstrates the lack of RPS in the southeast.

Figure 9.4. U.S. RPS Policies



Source: Database of State Incentives for Renewables & Efficiency

Thus, most of the states that make up what appears to be a prime market for SPP exports of renewables have no legal mandate to make renewable purchases. Only North Carolina has an RPS mandate, which requires utilities to purchase 12.5 percent of its energy from renewable resources by 2021 and its cooperatives and municipal utilities to purchase 10 percent of their power from renewable resources by 2018.[401] North Carolina is particularly distant from SPP's wind resources, raising the potential cost for transportation, and with part of North Carolina in another organized market (PJM), utilities in that state have other, closer options to meet renewable portfolio requirements.

Other states in the southeast, meanwhile, have only some tax and other financial incentives at the state and local level available to renewable energy developers, but no state-wide mandates. South Carolina's renewable portfolio "goal" relates only to distributed generation within its state borders.[402] All this suggests that, unless and until new mandates from state

[400] Database of State Incentives for Renewables & Efficiency, "Renewable Portfolio Standard Policies," September 2014, available at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.
[401] Database of State Incentives for Renewables & Efficiency, "North Carolina Incentives/Policies for Renewables & Efficiency," last updated October 31, 2014, available at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NC09R&re=0&ee=0.
[402] Database of State Incentives for Renewables & Efficiency, "South Carolina Incentives/Policies for Renewables & Efficiency," last updated January 9, 2015.

legislatures emerge in the southeast, other factors will have to drive demand for SPP's wind exports.

It is important, too, to note risk related to state RPS mandates and other environmental public policy, such as federal regulations from the U.S. EPA. Not all mandates are equal in dictating which technologies qualify and which do not. For example, some RPS mandates, such as in North Carolina,[403] have explicit carve outs for solar PV, while other states (like New York) do not. Future environmental regulations are inherently uncertain and may not mandate or provide credit for wind purchases, which would hurt SPP's odds of exporting wind power. This risk covers not just potential future RPS standards in states currently without them, but also federal policies, such as the U.S. EPA's Clean Power Plan. If, when finalized, that rule affords flexible implementation that allows states to consider alternatives to renewable resources in meeting environmental goals, or gives little or no credit to states for power from renewable resources, potential demand for SPP exports may be negatively impacted.

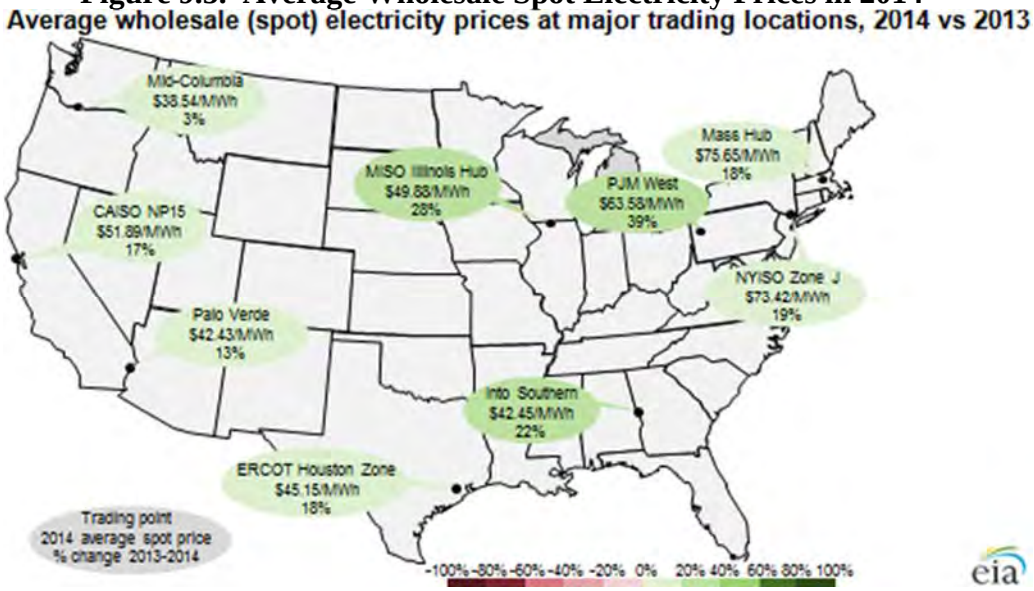
2. Economics

Renewable power – specifically wind – can provide attractive prices to potential buyers if able to take advantage of federal subsidies. The federal PTC – which provides a tax subsidy of 2.3 cents per kWh after tax[404] – has helped drive down costs of wind power to previously unprecedented levels. For example, according to a presentation from Ryan Wiser of the Lawrence Berkeley National Laboratory, the average price for PPAs for wind power from the U.S. interior region was 2.1 cents per kWh, or $21 per MWh.[405]

Such low prices would be attractive to any state in the U.S. Wholesale power prices in the U.S. as measured at major hubs ranged between approximately $38/MWh to $75/MWh, as shown in Figure 9.5 below. Note that the Southern hub, located at the Alabama-Georgia border, saw average spot prices of $42.45/MWh.

[403] Database of State Incentives for Renewables & Efficiency, "North Carolina Incentives/Policies for Renewables & Efficiency," last updated January 9, 2015. North Carolina Mandates that 0.2 percent of purchases come from solar resources by 2019.
[404] Database of State Incentives for Renewables & Efficiency, "Renewable Electricity Production Tax Credit."
[405] "2013 Wind PPA Prices In U.S. Interior Averaged 2.1 Cents/kWh (Windpower 2014)," Clean Technica, May 8, 2014, available at http://cleantechnica.com/2014/05/08/2013-ppa-prices-us-interior-averaged-2-1-centskwh-windpower-2014-part-2/.

Figure 9.5. Average Wholesale Spot Electricity Prices in 2014[406]



Source: EIA

Nevertheless, it is important to point out a major risk and a major cost associated with PTC-eligible wind. The risk is that the economic viability of these wind resources are highly dependent on the PTC, and thus is at constant risk of losing their primary economic driver. Currently, the PTC was renewed for 2014 and thus any wind project for which construction has begun and that has incurred 5 percent of its total costs before January 1, 2015, is eligible for the PTC.[407] The PTC has not yet been renewed beyond 2014. If, the PTC is not renewed beyond 2014, wind resources without the PTC would be less cost competitive with other sources of generation.

The additional cost associated with wind and solar generation is that of transmission. Renewable resources tend to be located far from load, making transmission investment an important consideration in the overall cost of wind and solar resources. This is especially true in the case of SPP exports, which may have to be transported across several states. Indeed, in SPP's most recent 20-year Integrated Transmission Plan, SPP estimated a need for $8.05 billion in new transmission investment to accommodate a scenario with large amounts of additional wind power, 10 GW of which was exported outside of SPP.[408] We address this issue in the next section.

3. Diversification Benefits

[406] U.S. Energy Information Administration, "Today in Energy," January 12, 2015, available at http://www.eia.gov/todayinenergy/detail.cfm?id=19531. Figure 9.5 also shows the percentage change in average wholesale spot prices from 2013 to 2014.

[407] Database of State Incentives for Renewables & Efficiency, "Renewable Electricity Production Tax Credit (PTC)," last updated December 22, 2014, available at http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F.

[408] Southwest Power Pool, "2013 Integrated Transmission Plan 20-Year Assessment Report," July 30, 2013 (SPP 2013 ITP), 94.

A third potential driver of demand for SPP wind exports is diversification. Historically, diversification of resource portfolios can be said to lower risks and decrease electricity price volatility than less diverse portfolios. Thus, if the price of a particular fuel rises sharply, more diversified portfolios are less impacted than those more singularly reliant on that fuel. Adding renewable resources, therefore, to traditional generation portfolios is one way to encourage benefits of diversification.

One recent study by IHS Energy attempts to quantify that benefit.[409] The IHS Diversity Study compares two portfolios: first, the existing U.S. generation mix, which features approximately 40 percent coal, 27 percent gas, 20 percent nuclear, 7 percent hydroelectric, 4 percent wind, and small amounts of solar, oil, and other technologies; second, a "Reduced Diversity" case, in which approximately 33 percent of installed capacity is from wind and solar, 62 percent is from natural gas, and 5 percent is from hydroelectric.[410] The IHS Diversity Study claims that "[t]he current diversified portfolio of US power supply lowers the cost of generating electricity by more than $93 billion per year, and halves the potential variability of monthly power bills compared to a less diverse supply."[411]

The overall takeaway from the IHS Diversity Study is that it confirms the conventional wisdom that a diverse portfolio of generation resources can lower the cost of generating electricity. However, there is an additional nuance to the Study which is that "more diversity" does not mean "more renewables;" on the contrary, the "Reduced Diversity" case, which "increases average wholesale power prices by about 75% and retail power prices by 25%,"[412] models substantially more wind and solar than the current U.S. generation mix. The IHS Diversity Study is a warning against overreliance on wind, solar, and natural gas resources, and therefore any diversification benefits associated with additional wind and solar from SPP's exports may be dependent on the buying utility's existing resource portfolio and whether buying wind (or solar) from SPP increases or decreases diversity for the buyer.

One additional point related to resource diversity is how each state has used renewables to address environmental policies, both existing and future. Some states, like many SPP states, have procured significant amounts of renewable resources, especially wind, in response to RPS standards or federal environmental regulations. Other states – especially those in the southeast – have pursued non-renewable investments, such as integrated gasification combined cycle (IGCC) and/or nuclear generation. Going forward, these states may be more receptive to procuring power from renewable resources to help diversify their response to current and future environmental regulations, if only because some of the IGCC and nuclear investments have resulted in substantial cost overruns and delays. For example, the expansion of Southern Company's Vogtle nuclear facility in Georgia, which was expected to cost $6.1 billion and be completed by 2016.[413] Current estimates for Vogtle's expansion are to be completely online by

[409] IHS Energy, *The Value of US Power Supply Diversity*, July 2014 (IHS Diversity Study).
[410] IHS Diversity Study, 5.
[411] IHS Diversity Study, 5.
[412] IHS Diversity Study, 5.
[413] Thomas Overton, "Even More Delays and Cost Overruns for Vogtle Expansion," *Power Magazine*, February 2, 2015, available at http://www.powermag.com/even-more-delays-and-cost-overruns-for-vogtle-expansion/.

mid-2020 at a cost of $7.4 billion.[414]

C. Transport

Even with ample supply in SPP and sufficient demand for SPP exports, the third issue related to SPP's export potential is transmission of those exports. To export, SPP needs transmission capacity to do so. More than likely, SPP will need additional transmission expansion to accommodate significant amounts of exports. As noted earlier, in its most recent 20-year transmission plan, SPP modeled a future scenario that assumed a 20 percent *federal* Renewable Electricity Standard that required approximately 16.5 GW of nameplate wind capacity, plus approximately 10 GW of additional wind generation to be exported outside of SPP.[415] Under that scenario, SPP estimated a need for a total of $9 billion of additional transmission investment ($8.05 billion of which is needed to accommodate the additional wind generation), totaling 6,766 total miles of new transmission lines and 22 new transformers.[416]

Figure 9.6. Hypothetical Transmission Buildout Needed to Accommodate 20 percent Federal RPS plus 10 GW of SPP Wind Exports[417]

Source: 2013 SPP ITP, Figure 13.3

[414] Ibid.
[415] 2013 SPP ITP, 9.
[416] 2013 SPP ITP, 94.
[417] 2013 SPP ITP, Figure 13.3.

There are two primary options for transmission expansion to accommodate wind exports: (a) expansion of the AC grid, using both SPP's existing ITP process and its interregional planning efforts with neighboring control areas; and (b) new HVDC lines. Both options offer benefits and challenges.

Building out the AC grid has the advantage of using SPP's existing ITP process, which considers reliability, economic, and public policy projects at once. It also allows SPP to use its existing Highway-Byway cost allocation mechanism, which can allow for greater cost sharing among all entities that benefit from new projects. Further, building out the AC grid may have ancillary benefits related to increasing the reliability of the SPP system.

Expansion of the AC system will not be without challenges, however. First, it is expensive. As noted above, SPP's own analysis suggests a need for $9 billion in additional transmission investment to accommodate a scenario with 20 percent federal Renewable Electricity Standard and 10 GW of wind exports from SPP.[418] Significant new wind resource penetration on the SPP grid may also test system operators' ability to maintain reliable grid operation. And as we note in chapter 7 of this Report, SPP will want to be wary of customer recoil against paying for additional transmission investment, especially if such investment is perceived to primarily benefit wind developers instead of internal customers. Indeed, it has been suggested that SPP's Highway-Byway approach is "not appropriate" for export projects.[419] SPP wind exports may impact flows on other neighboring transmission systems, potentially requiring SPP to compensate those systems. Second, it will require interregional coordination and investment with neighboring control areas. As noted by the Brattle Group in a recent report for The Nebraska Power Review Board, exports out of SPP to the east, including the southeastern states, "would be challenging because the interregional transmission planning efforts of SPP and MISO are currently still under development and will need significant improvements before they are able to effectively plan large transmission upgrades across the RTOs' boundaries."[420] Brattle continues that "those improvements will take a few years to materialize and, once transmission upgrades across the seams are identified and approved, a few more years will be required for their development and construction."[421] Brattle finds that exporting SPP wind to the west – i.e., to the Western Electricity Coordinating Council, or WECC – "will be particularly challenging due to the cost of building transmission across the Eastern and Western interconnections" and that "overcoming transmission constraints…would impose significant costs" on ratepayers.[422]

A second option for transporting SPP wind exports is through new HVDC transmission projects. HVDC projects "offer developers the chance to transmit excess, cheaper power over long distances to load pockets with high prices, and/or move renewable energy from remote locations to load centers in states with renewable portfolio standards."[423] HVDC solves some of the issues related to AC expansion, particularly by simplifying the cost allocation and interregional aspects of new infrastructure investment. This is because HVDC has a more "limited system impact than alternating current (AC) lines; for example, since HVDC projects

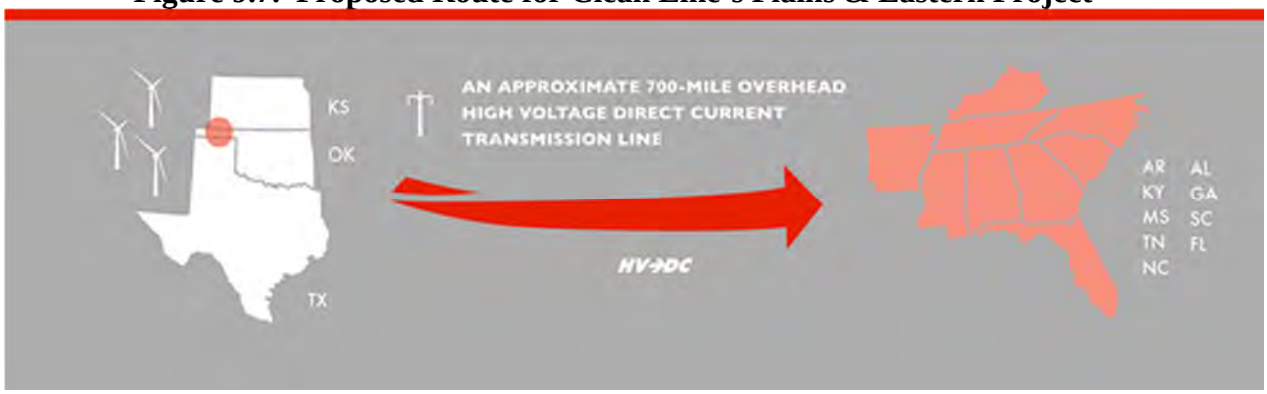
[418] 2013 SPP ITP, 94.
[419] RTO Insider Article.
[420] Chang, et al., "Nebraska Renewable Energy Exports: Challenges and Opportunities," The Brattle Group, December 12, 2014 (Brattle Export Study), 49.
[421] Brattle Export Study, 49.
[422] Brattle Export Study, 49.
[423] 2014 Looking Forward Report, 59.

are controllable, they do not produce parallel flows (i.e., loop flows) on the system."[424] In addition, HVDC projects are typically merchant transmission projects, which means that a private, non-incumbent transmission owner takes the entirety of the project's market risk and assigns costs only to customers that voluntarily purchase service on the project.

However, HVDC also has costs and risks. First, HVDC is also expensive and requires substantial margins to justify the risks to merchant developers. For example, Clean Line Energy Partners, a merchant transmission developer pursuing at least five merchant transmission projects across the U.S., estimates that four of those projects will cost between $2 billion and $2.5 billion.[425] Second, siting and permitting HVDC lines can be a lengthy, uncertain process, especially for projects that cross multiple jurisdictions. Several merchant lines under development have not met their initial estimated energization dates, having been subject to long local, state, and federal regulatory review processes.[426]

Clean Line Energy Partners' Plains & Eastern transmission line is one example of a merchant HVDC project under development. The proposed project route, shown below in Figure 9.7, would deliver up to 3,500 MW of wind power from the Oklahoma panhandle region approximately 700 miles to the "Mid-South and Southeastern United States."[427] Clean Line states that the "development and construction of the Plains & Eastern [project] is estimated to cost approximately $2 billion and will make possible more than $7 billion of new renewable energy investments."[428] Clean Line has received regulatory approvals in Oklahoma and Tennessee[429] and has other pending regulatory proceedings, including at the U.S. DOE.[430]

Figure 9.7. Proposed Route for Clean Line's Plains & Eastern Project[431]



[424] 2014 Looking Forward Report, 59.
[425] Clean Line Energy Partners, "Projects," available at http://www.cleanlineenergy.com/projects.
[426] For example, the Zephyr transmission project has been in development since 2008 but is not expected to be online until 2020. 2014 Looking Forward Report, 59.
[427] Clean Line Energy Partners, "Plains & Eastern Clean Line Overview," available at http://www.plainsandeasterncleanline.com/site/page/project-description.
[428] Clean Line Energy Partners, "Plains & Eastern Clean Line Overview," available at http://www.plainsandeasterncleanline.com/site/page/project-description.
[429] Clean Line Energy Partners, "Plains & Eastern Clean Line State Regulatory Processes and Approvals," available at http://www.plainsandeasterncleanline.com/site/page/state-regulatory-approvals.
[430] Clean Line Energy Partners, "Plains & Eastern Clean Line Federal Regulatory Processes and Approvals," available at http://www.plainsandeasterncleanline.com/site/page/federal-regulatory-approvals.
[431] Clean Line Energy Partners, "Plains & Eastern Clean Line Overview," available at http://www.plainsandeasterncleanline.com/site/page/project-description.

Source: Clean Line Energy Partners, "Plains & Eastern Clean Line Overview," available at http://www.plainsandeasterncleanline.com/site/page/project-description

A second Clean Line project – the $2 billion Rock Island project – would connect up to 3,500 MW of wind from northeast Nebraska and the WAPA Upper Great Plains area to eastern power markets.[432] The Rock Island project has received regulatory approvals at FERC and in Illinois, with approval still pending in Iowa.[433] That project's proposed route is below in Figure 9.8.

Figure 9.8. Proposed Route for Clean Line's Rock Island Project[434]

Source: Clean Line Energy Partners, "Rock Island Clean Line Overview," available at http://www.rockislandcleanline.com/site/page/project-description

D. Bottom Line and Next Steps

Summing up, the prospects for exports of SPP's wind requires excess wind supply in SPP, sufficient demand in another control area for imported wind, and adequate transmission to transport the exported wind power reliably. Regarding supply, the picture is positive, as SPP has the excess wind power supply to export with substantially more wind (plus 2,000 MW of solar) under development. Regarding demand, challenges abound, as the southeastern states lack renewable portfolio standard mandates and the economics of wind are reliant on subsidies, like the PTC. Regarding transport, more exports likely mean more transmission investment and interregional collaboration with other control areas, or could require new HVDC lines.

Going forward, SPP can begin by considering its own value proposition for wind. The primary benefit to SPP states from additional wind exports will likely be economic, in the form of new jobs in states like Oklahoma. For example, Clean Line estimates that its Plains & Eastern project will provide "more than 5,000 construction jobs and over 500 direct jobs maintaining and

[432] Clean Line Energy Partners, "Rock Island Clean Line Overview," available at http://www.rockislandcleanline.com/site/page/project-description.
[433] Clean Line Energy Partners, "Rock Island Clean Line Regulatory Approvals," available at http://www.rockislandcleanline.com/site/page/regulatory-approvals.
[434] Clean Line Energy Partners, "Rock Island Clean Line Overview," available at http://www.rockislandcleanline.com/site/page/project-description.

operating the wind farms and the transmission line,"[435] plus indirect jobs such as manufacturing of turbines, towers and cable, and hospitality. An ancillary benefit, if exports are transported over the AC grid, is any additional reliability which accrues to the benefit of the existing SPP grid from AC expansion projects.

Next, SPP should consider its target markets for its exports. For example, the southeastern states have yet to adopt RPS standards and instead have focused on nuclear and clean coal investments, some of which have turned out more costly than originally projected. These states may be ready for a new approach in addressing environmental policy, one that involves renewable resources beyond small pilot and distributed projects.

If SPP considers it worthwhile to pursue wind exports, it may consider playing a role of facilitator of further discussions between developers, policymakers, legislators, and utilities. One idea for SPP's consideration is to host a free-of-charge expo in a major target market city, which could be funded, attended, and staffed by wind and transmission developers seeking to secure buyers for SPP export projects. Attendees could include utilities that may purchase renewable power imports, state public utilities commissions, state legislators, and wind and transmission developers. Developers could use the opportunity to demonstrate (a) the economics of SPP's wind exports, (b) the benefits of a more diverse portfolio, one which includes additional renewable power, and (c) the environmental compliance benefits of renewable power.

In addition, SPP should continue to work with its neighbors on developing mechanisms for interregional coordination on new transmission investment. As noted by the Brattle Group, "few effective and actionable planning processes currently exist for transmission upgrades across regional boundaries."[436] Finalizing a process for planning and allocating cost of transmission projects that span multiple regions will lower the barriers to getting new projects built to support additional SPP renewable power exports.

[435] Clean Line Energy Partners, "Plains & Eastern Clean Line Benefits," available at: http://www.plainsandeasterncleanline.com/site/page/benefits.
[436] Brattle Export Study, 33.

Attachment E

December 13, 2008 Correspondence

NYISO, PJM, ISO-NE email to JCSP

February 4, 2009 Correspondence

NYISO & ISO-NE letter to JCSP

May 4, 2009 Correspondence

Mid-Atlantic Governors Oppose JCSP

LETTER TO MISO/SPP RE: JCSP STUDY

SENT BY E-MAIL ON 12/31/08

Dear Jon/Nick,

NYISO, PJM and ISO-NE have some concerns about the JCSP report that is scheduled to be released in early January and wanted to bring the issue to your attention. The note below highlights some of our concerns and we would like to schedule a conference call to discuss the issue further.

The JCSP represents a significant body of work and all involved should be commended. It successfully demonstrates the ability to coordinate large scale scenario analysis studies over the entire U.S. eastern interconnection. However, it is only a first step as the work plan contemplated for 2009 illustrates. There are a great many issues that require further resolution before any transmission overlay can be deemed viable or actionable from an engineering, economic, or policy perspective.

While the JCSP report acknowledges these issues, it goes beyond the presentation of the results of this first step scenario analysis to attempt to justify the proposed transmission overlay as a viable plan.

It seems premature to be discussing specific cost/benefit ratios, impacts to transmission rates, and allocation of costs until further analyses can be performed to evaluate alternative source scenarios and to optimize delivery infrastructure. Many more scenarios and detailed follow-up analysis is required prior to reaching major conclusions. For example, the development of large amounts of wind in the Midwest coupled with carbon emission restrictions could lead to the potential retirement of coal units, thus obviating the need for much of the transmission overlay. Similarly, off-shore wind and energy efficiency may be deliverable to customers much sooner than Midwest wind and may significantly reduce long haul transmission requirements even if it is less plentiful. Additional discussion on the capital costs of the wind resources, as well as the transmission facilities costs, would provide a better understanding of the true costs of the wind expansion scenario. Furthermore, greater emphasis needs to be placed on the need for substantial upgrades to local transmission systems to facilitate the delivery of energy to customers from large backbone HVDC lines injecting into the northeast.

Until all of these various costs are understood, no single transmission plan can be presented as a solution to the renewable energy issue. We would also like to re-state our position that the JCSP is not the appropriate structure for discussion of “value based planning”.

Our goal in sending this email is to ask that the further distribution of the JCSP report be delayed for a short period so that these issues can be resolved to our mutual satisfaction. It is in all of our best interests for this work to be portrayed in the best possible light and for us to be able to move forward together to provide for the planning needs of the eastern interconnection as energy policy evolves during the coming year. As noted previously, we would be happy to arrange for a conference call over the next few days to discuss further how best to proceed.

Thanks for your attention to this matter.

Best Regards,

Steve Whitley

Terry Boston

Vamsi Chadalavada (in Gordon van Welie’s stead)

Tim Ponseti (TVA)

Gordon van Welie
President and Chief Executive Officer

Stephen G. Whitley
President and Chief Executive Officer

February 4, 2009

TO: THE JOINT COORDINATED SYSTEM PLANNING INITIATIVE

ISO New England and the NYISO are pleased to participate in the Joint Coordinated System Plan (JCSP) initiative that comprises nearly all of the regional planning entities for the Eastern Interconnection. We believe this type of broad, long-term and cooperative approach to power system planning and development is important to inform federal energy policy under the new administration.

The JCSP is a highly valuable activity with respect to the collaboration it promotes among the regional planning organizations within the Eastern Interconnection and the tools it has developed. Even at this early stage of the process, the JCSP has established a framework in which to study the entire Eastern Interconnection in a single multi-regional analysis and developed a common database of information that can be used as a starting point for future studies.

The current JCSP reports on the activities undertaken in 2008, presents analyses of two wind expansion scenarios, that also assume significant baseload coal expansion, and recommends further scenarios for the group to study. ISO New England and NYISO support the JCSP recommendation to pursue additional studies and scenarios and believe these steps are required prior to reaching any broad conclusions on the need for, and scope of, development of large scale transmission. In this regard, the 2008 JCSP report cannot be viewed as a "plan" to be relied upon for decision-making purposes and we believe its publication is premature.

Our primary concern is that the report portrays its analyses to date as a basis for federal policy discussions and decisions regarding major transmission development, as it relates to the integration of renewable resources, notwithstanding the recognized need for additional work. Until additional scenarios that include the development of local resources are analyzed, we do not believe any single transmission plan can be presented as a solution to the integration of additional renewable energy resources in the United States. Conversely, there is significant value in the JCSP studies for policymakers if appropriately presented as technical scenario analysis -- coupled with the incorporation of specific planning work already underway in the various regions, including New England and New York, to integrate local renewable resources.

We also have concerns about the inclusion of issues such as cost allocation and "value based planning" considerations in the JCSP report. Since the JCSP is not itself a policy making body, we do not believe these issues should be part of the current scope nor are they appropriate for future JCSP efforts. In fact, we feel that issuing the report as it stands has the potential to constrain future collaboration, and at worst, stimulate counter-productive debate amongst regional planning organizations at it relates to these two policy areas.

In order to ensure that ISO New England's and NYISO's specific concerns are fully understood, below is a description of some of the specific activities and initiatives going on in the region and an explanation of how we believe they impact certain JCSP study assumptions and future efforts.

The New England Governors have been working actively for the past two years, not only among the six states in the region, but also in collaboration with the five eastern Canadian provinces of Quebec, Ontario, Newfoundland and Labrador, New Brunswick and Nova Scotia, to consider the integrated development of renewable and non-carbon emitting resources. Numerous proposals to develop renewables within the region (over 4800 MW in the current ISO New England Interconnection queue), including two major off shore wind projects, are being pursued by private entities. The governors and energy policymakers strongly support these developments and view them as economic development opportunities for their states -- as well as for advancing air quality and energy security goals. Recently, the governors asked ISO New England for assistance in creating a "blueprint" for developing regional energy resources and overcoming transmission barriers to enhance the energy independence of the region. Furthermore, a number of initiatives in the New England states are promoting energy efficiency and smart grid technologies. These are in addition to demand resources that are expected to comprise over 8% of the resources procured for our Forward Capacity Market for the year 2011.

New York State has put into place an aggressive policy to incent the development of a substantial level of both renewable resources as well as energy efficiency. In his recent State-of-the-State message Governor Paterson announced a further expansion of the State's efforts to achieve a "45x15" goal: i.e. a 30% level of renewable resources and a 15% reduction in the forecasted energy usage in the State by the year 2015. The energy efficiency program alone, if these goals are achieved, will reduce statewide electric demand by over 5000MW. New York already has nearly 1000MW of wind resources now in operation and the NYISO has another 8000MW in its interconnection queue, including off-shore projects totaling over 1200MW. The NYISO is working with regulators and stakeholders in New York to analyze the local transmission reinforcements that may be required to fully integrate such substantial local wind resources into the wholesale electric markets for the benefit of all consumers in the State.

With the shared geography and history of energy trading patterns between New York and New England with Eastern Canada, significant consideration is also being given to transmission options that would strengthen our access to new supplies of renewable energy—both hydro and wind—now being developed north of our states in Canada. Given these activities, it is reasonable to assume that these resources being developed in the Northeast may be deliverable to customers in our region sooner and more cost-effectively than Midwest wind resources. Given the renewable development, energy efficiency, and likelihood of new ties to Canada, the need to construct long transmission lines to the Midwest would likely be reduced and in turn overall transmission costs may be lower. We believe New England and New York policymakers and stakeholders should have the opportunity to compare such a scenario with the scenarios assumed in the current JCSP report and urge that they be included in future JCSP planning efforts.

We note that the report also assumes the development of new coal-fired generation in the Midwest without recognition of current and future restrictions on carbon emissions and their associated costs. While there is significant uncertainty about the details and timing of federal regulations for carbon, the Regional Greenhouse Gas Initiative ("RGGI") is in effect today in New England, New York and other Northeast states and its impacts on generation from coal fired resources remains to be seen. In addition, we believe it is likely that the transmission and wind project capital cost estimates contained in the initial JCSP are understated and suggest that modifications to the estimates and estimating process would help to develop a better understanding of the true costs of the expansion scenarios. Future JCSP efforts should also include the ability of stakeholders in the various regions to consider and comment on the assumptions used for these estimates.

These factors, especially the lack of recognition of important New England and New York-specific circumstances require that ISO New England and NYISO withdraw from the publication of the current

JCSP study. Despite our inability to participate in the JCSP 2008 report, we intend to continue to participate and work collaboratively towards the modifications suggested above. In order to advance the positive steps made by the participants and the Department of Energy toward joint planning initiatives, we hope that agreement can be reached on the charter, governance and scope of additional JCSP planning efforts and an improved regional stakeholder review process.

Sincerely,

Gordon van Welie
President & Chief Executive Officer
ISO New England Inc.

Stephen G. Whitley
President & Chief Executive Officer
New York Independent System Operator

cc: John Bear, MISO
Terry Boston, PJM
Nick Brown, SPP, Inc.
Daniel Fredrickson, MAPP
David Meyer, DOE
Tim Ponseti, TVA

Massachusetts | Rhode Island | Delaware | Maine | Maryland

New Hampshire | New Jersey | New York | Vermont | Virginia

May 4, 2009

The Honorable Harry Reid
Majority Leader
U.S. Senate
Washington, DC 20510

The Honorable Mitch McConnell
Minority Leader
U.S. Senate
Washington, DC 20510

The Honorable Nancy Pelosi
Speaker
U.S. House of Representatives
Washington, DC 20515

The Honorable John Boehner
Minority Leader
U.S. House of Representatives
Washington, DC 20515

Dear Senator Reid, Senator McConnell, Speaker Pelosi, Representative Boehner,

As Governors from Northeast and Mid-Atlantic states, we applaud your support for renewable energy and its role in enhancing clean energy job creation, increasing our energy security and curbing greenhouse gas emissions.

We write to encourage you to support strong new federal policies to promote wind resources. In addition to recognizing the potential for wind resources in the Midwest, we believe that the wind resources of the Eastern seaboard states – both onshore and offshore wind – represent one of our nation's most promising yet underdeveloped source of renewable energy. At the same time, we must express our concern about the significant risks posed by recent proposals regarding transmission that we believe could jeopardize our states' efforts to develop wind resources and inject federal jurisdiction into an area traditionally handled by states and regions.

Significant onshore or offshore wind projects have been proposed or planned for almost all of the Northeast and Mid-Atlantic states. Several of our states already have significant land-based wind projects installed or well underway and have established aggressive wind development goals. Moreover, the waters adjacent to the East Coast hold potential for developing some of the most robust wind energy resources in the world – enough wind potential to meet total U.S. electricity demand, as Interior Secretary Ken Salazar has recently pointed out. Congress should put its full support behind the development of these resources.

Current legislative proposals focused on transmission, in contrast, would designate national corridors for transmission of electricity from the Midwest to the East Coast, with the costs for that transmission allocated to all customers. While we support the development of wind resources for the United States wherever they exist, this ratepayer-funded revenue guarantee for land-based wind and other generation resources in the Great Plains would have significant, negative consequences for our region: it would hinder our efforts to meet regional renewable energy goals with regional resources and would establish financial conditions in our electricity markets that would impede development of the vast wind resources onshore and just off our shores for decades to come. In addition, the legislative proposals for selective federal subsidy for certain land-based wind resources paired with the practice of dispatching the lowest cost available generation resource could result in surplus transmission capacity or artificially inflated energy prices for Midwest renewables being paid by east coast ratepayers. Such an outcome would have negative consequences for consumers, regional energy sufficiency and the environment. Moreover, it is well accepted that local generation is more responsive and effective in solving reliability issues than long distance energy inputs.

Land-based wind energy projects, which have already proven themselves economical in the Northeast, must have the chance to move forward. And while offshore wind installation costs currently exceed those of onshore installations, these resources are much closer to our load centers and research and development efforts focused on reducing costs and improving reliability promise to make offshore wind competitive with Midwest wind farms on a delivered cost of power basis. As regional onshore projects move forward and offshore wind moves into commercialization in the United States, they all must have the opportunity to compete on an even playing field with on-shore, yet remote, sources of power from the Midwest and not be disadvantaged by upfront transmission subsidies.

If transmission is to be addressed in energy legislation at all, we believe Congress should focus its attention on regional solutions. In our regions, this means continuing to pursue planned wind and other renewable resources within our competitive energy markets framework. For offshore wind, this means a new offshore wind transmission backbone to facilitate the interconnection of offshore renewable energy resources to major load centers along the East Coast. Development of this offshore network will require the attention of the Department of Energy, the Minerals Management Service (MMS) and the Federal Energy Regulatory Commission (FERC), as part of an Outer Continental Shelf energy resource development plan.

In our view, legislation to promote renewable energy resources on a fair, equitable, and efficient basis should, at a minimum:

- Create strong federal energy efficiency and renewable energy incentives that are simple, transparent and technology neutral – and capitalize on more than a decade of successful direct experience by many states in developing strong efficiency and renewable energy markets;

- Consider new market mechanisms such as regional procurements for renewable energy in the form of long-term power purchase agreements – again, allowing all renewable generation interests to compete on the basis of total cost of power delivered to load centers;

- Encourage that state and regional planners along the Atlantic coast develop a plan within and across regions to accommodate growing availability of onshore wind resources and to establish an offshore wind transmission regime, including new FERC policies tailored to the special circumstances of offshore wind and expedited siting review for offshore lines in federal waters and their interconnection to coastal load centers with appropriate state involvement.

- Encourage FERC and NERC to support and facilitate robust planning within regional transmission organizations that provides and promotes local renewable resources integration and preserves local oversight and review.

- Evaluate whether expanding the federal Investment Tax Credit would be a more effective, simpler, and technology neutral mechanism for promoting renewable energy development across the country than a focus on transmission, which tends to support remote onshore wind, but disadvantage nearby offshore wind.

Thank you for your attention to this critical issue.

Sincerely,

Governor Deval Patrick
Massachusetts

Governor Donald L. Carcieri
Rhode Island

Governor Jack Markell
Delaware

Governor John Baldacci
Maine

Governor Martin O'Malley
Maryland

Governor John H. Lynch
New Hampshire

Governor Jon S. Corzine
New Jersey

Governor David A. Paterson
New York

Governor James H. Douglas
Vermont

Governor Timothy M. Kaine
Virginia

cc: Chairman Jeff Bingaman
Ranking Member Lisa Murkowski
Chairman Henry Waxman
Ranking Member Joe Barton
Secretary Steven Chu
Secretary Ken Salazar
Honorable Carol Browner

Attachment F

2015 MISO Members by Sector

MISO
MEMBERS BY SECTOR
(June 2015)

I. TRANSMISSION OWNERS

1. ALLETE, Inc. (for its operating division Minnesota Power, Inc., and its wholly-owned subsidiary, Superior Water, Light and Power Company)
2. Ameren Illinois Company
3. Ameren Missouri
4. Ameren Transmission Company of Illinois[1]
5. American Transmission Company, LLC
6. Ames Municipal Electric System
7. Arkansas Electric Cooperative Corporation
8. Big Rivers Electric Corporation
9. Board of Water, Electric, and Communications Trustees of the City of Muscatine, Iowa
10. City of Alexandria, Louisiana
11. City of Rochester, a Minnesota Municipal Corp (Public Utility Board)[2]
12. Central Minnesota Municipal Power Agency
13. Cleco Power LLC
14. Columbia, Missouri, City of (Water & Light Dept.)
15. Dairyland Power Cooperative
16. Duke Energy Business Services, LLC for Duke Energy Indiana, Inc.
17. East Texas Electric Cooperative, Inc.
18. Entergy Arkansas, Inc.
19. Entergy Gulf States Louisiana, L.L.C.
20. Entergy Louisiana, LLC
21. Entergy Mississippi Inc.
22. Entergy New Orleans, Inc.
23. Entergy Texas, Inc
24. Great River Energy
25. Hoosier Energy Rural Electric Cooperative, Inc.
26. Indiana Municipal Power Agency
27. Indianapolis Power & Light Company
28. International Transmission Company (d/b/a ITC Transmission)
29. ITC Midwest LLC
30. Lafayette City-Parish Consolidated Government
31. Michigan Electric Transmission Company, LLC
32. Michigan Public Power Agency
33. Michigan South Central Power Agency
34. MidAmerican Energy Company
35. Minnesota Municipal Power Agency
36. Missouri River Energy Services
37. Montana-Dakota Utilities, Co., a division of MDU Resources Group, Inc.
38. Municipal Electric Utility of the City of Cedar Falls, Iowa
39. Northern Indiana Public Service Company[3]
40. Northern States Power Company and Northern States Power Company (Wisconsin)
41. Northwestern Wisconsin Electric Company
42. Otter Tail Power Company
43. Prairie Power, Inc.
44. South Mississippi Electric Power Association
45. Southern Illinois Power Cooperative

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1 Pursuant to Article Two, Section VI(A)(1) of the MISO Transmission Owners Agreement, Ameren Transmission Company of Illinois also participates in the Competitive Transmission Developers stakeholder group.

2 Pursuant to Article Two, Section VI(A)(1) of the MISO Transmission Owners Agreement, City of Rochester participates in the Municipals/Cooperatives/Transmission Dependent Utilities stakeholder group.

3 Pursuant to Article Two, Section VI(A)(1) of the MISO Transmission Owners Agreement, Northern Indiana Public Service Company also participates in the Power Marketers/Brokers stakeholder group.

MISO
MEMBERS BY SECTOR
(June 2015)

TRANSMISSION OWNERS (cont'd.)

46. Southern Indiana Gas & Electric Company (Vectren)
47. Southern Minnesota Municipal Power Agency
48. Springfield, IL, City of (Office of Public Utilities)
49. Wabash Valley Power Association, Inc.
50. Wilmar Municipal Utilities[4]
51. Wolverine Power Supply Cooperative, Inc.

II. COORDINATION MEMBER

1. Manitoba Hydro

III. IPPs/EWGs

1. Beacon Power, LLC
2. Benton County Wind Farm, LLC
3. Boston Energy Trading and Marketing LLC
4. Calpine Energy Services, L.P.
5. Duke Energy Commercial Asset Management, Inc.
6. Dynegy Power Marketing, LLC
7. EDF Renewable Development, Inc.
8. EDP Renewables North America LLC
9. Entergy Nuclear Power Marketing, LLC
10. E.ON Climate & Renewables North America, LLC
11. GenOn Energy Management, LLC
12. Geronimo Wind Energy, LLC
13. Iberdrola Renewables, LLC
14. Invenergy Energy Management LLC
15. Lively Grove Energy Partners, LLC
16. LS Power Associates, L.P.
17. Midland Cogeneration Venture Limited Partnership
18. NextEra Energy Power Marketing LLC
19. NRG Energy, Inc.
20. Prairie State Generating Company LLC
21. RES America Developments Inc.[5]
22. RRI Energy Services, LLC
23. Springfield Project Development LLC

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[4] Willmar Municipal Utilities received Board approval of its Transmission-Owning Membership application on 04/23/2015. Willmar's anticipated integration in MISO is currently scheduled for 01/01/2016.

[5] Pursuant to Article Two, Section VI(A)(1) of the MISO Transmission Owners Agreement, RES America Developments Inc. also participates in the Competitive Transmission Developers stakeholder group.

MISO
MEMBERS BY SECTOR
(June 2015)

IV. MUNIS/COOPS/TDUs

1. Alliant Energy Corporate Services, Inc.
2. American Municipal Power, Inc.
3. Basin Electric Power Cooperative
4. Beauregard Electric Cooperative, Inc.
5. Buckeye Power, Inc.
6. City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power
7. City of Lansing By its Board of Water and Light
8. Claiborne Electric Cooperative, Inc.
9. Consumers Energy Company
10. Great Lakes Utilities
11. Heartland Consumers Power District
12. Illinois Municipal Electric Agency
13. Integrys Energy Group Incorporated
14. Jefferson Davis Electric Co-Operative, Inc.
15. Lincoln Electric System
16. Madison Gas & Electric Company
17. Missouri Joint Municipal Electric Utility Commission
18. Pointe Coupee Electric Membership Corporation
19. South Louisiana Electric Cooperative Association
20. Southwest Louisiana Electric Membership Corp.
21. Washington-St. Tammany Electric Cooperative, Inc.
22. WAPA-Upper Great Plains Region
23. Wisconsin Electric Power Company
24. WPPI Energy

V. END-USER CUSTOMERS

1. Alcoa Power Generating Incorporated
2. ArcelorMittal USA LLC
3. Association of Businesses Advocating Tariff Equity
4. Century Aluminum of Kentucky General Partnership
5. Coalition of MISO Transmission Customers
6. Illinois Industrial Energy Consumers (f/k/a Caterpillar)
7. Midwest Industrial Customers (c/o Wisconsin Industrial Energy Group, Inc.)
8. Texas Industrial Energy Consumers

MISO
MEMBERS BY SECTOR
(June 2015)

VI. COMPETITIVE TRANSMISSION DEVELOPERS

1. Abengoa Transmission Holdings, LLC
2. AEP Transmission Holding Company, LLC
3. Anbaric Holding, LLC
4. AltaLink Investments L.P.
5. Brookfield Infrastructure Group Corporation
6. Duke-American Transmission Company, LLC
7. Edison Transmission, LLC
8. Eversource Energy Transmission Ventures, Inc.
9. Exelon Transmission Company, LLC
10. GridAmerica Holdings Inc.
11. Hunt Transmission Services LLC
12. Iccenlux, Corp
13. ITC Midcontinent Development LLC
14. Midcontinent MCN, LLC
15. Midwest Power Transmission Illinois, LLC
16. NextEra Energy Transmission, LLC
17. NextEra Energy Transmission Midwest, LLC
18. OGE Transmission, LLC
19. Oklahoma Gas & Electric Company
20. Pattern Transmission LP
21. Public Service Enterprise Group Incorporated
22. Republic Transmission, LLC
23. Transource Energy, LLC
24. Xcel Energy Transmission Development Co., LLC

MISO
MEMBERS BY SECTOR
(June 2015)

VII. POWER MARKETERS/BROKERS

1. American Electric Power Service Corporation (as agent for the AEP Operating Companies)
2. Barclays Bank PLC
3. BP Energy Company
4. Cargill Power Markets, LLC
5. Castleton Commodities Merchant Trading L.P.
6. Citadel Energy Investments, LTD.
7. Citigroup Energy Inc.
8. DC Energy, LLC
9. Direct Energy Business LLC
10. DTE Energy
11. Dynegy Energy Services, LLC
12. EDF Trading North America, LLC
13. EWO Marketing, LLC
14. Exelon Corporation
15. Exelon Generation Company, LLC
16. FirstEnergy Solutions Corp.
17. H. Q. Energy Services (U.S.) Inc.
18. Illinois Power Marketing Company
19. J. Aron & Company
20. KCP&L Greater Missouri Operations Company
21. LG&E and KU Services Company, as agent for Louisville Gas and Electric Company and Kentucky Utilities Company
22. Linde Energy Services, Inc.
23. Mercuria Energy America, Inc.
24. Monterey MW, LLC
25. Morgan Stanley Capital Group Inc.
26. Noble Americas Gas & Power Corp.
27. Ontario Power Generation Inc.
28. PSEG Energy Resources & Trade LLC
29. Royal Bank of Canada
30. Saracen Energy Midwest LP
31. SESCO Enterprises, LLC
32. Shell Energy North America (US), L.P.
33. Solios Power LLC
34. South Jersey Energy Company
35. Talen Energy Marketing, LLC (fka PPL EnergyPlus, LLC)
36. Tenaska Power Services Co.
37. The Dayton Power and Light Company
38. The Energy Authority
39. Twin Cities Power, LLC
40. Vitol Inc.
41. Westar Energy, Inc.
42. XO Energy MW, LP

MISO
MEMBERS BY SECTOR
(June 2015)

VIII. ENVIRONMENTAL/OTHER STAKEHOLDR GROUP[6] (Non-Members)

1. Citizens Action Coalition of Indiana
2. Clean Line Energy Partners LLC
3. Clean Wisconsin
4. Environmental Law & Policy Center
5. Fresh Energy
6. Great Plains Institute
7. Natural Resources Defense Council
8. Sierra Club
9. Southern Wind Energy Association
10. Sustainable FERC Project
11. Union of Concerned Scientists
12. Wind on the Wires

IX. STATE REGULATORY AUTHORITIES[7] (Non-Members)

1. Arkansas Public Service Commission
2. Illinois Commerce Commission
3. Indiana Utility Regulatory Commission
4. Iowa Utilities Board
5. Kentucky Public Service Commission
6. Louisiana Public Service Commission
7. Manitoba Public Utilities Board
8. Michigan Public Service Commission
9. Minnesota Public Utilities Commission
10. Mississippi Public Service Commission
11. Missouri Public Service Commission
12. Montana Public Service Commission
13. New Orleans City Council Utilities Regulatory Office
14. North Dakota Public Service Commission
15. Public Utility Commission of Texas
16. South Dakota Public Utilities Commission
17. Wisconsin Public Service Commission

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6 The entities comprising the environmental and other stakeholder group on the Advisory Committee are not members of MISO; rather, they are representatives of stakeholder groups serving on the Advisory Committee, which have been chosen by recognized environmental and other stakeholder organizations having an interest in the activities of MISO.

7 The entities comprising the state regulatory authorities on the Advisory Committee are not members of MISO; rather, they are (i) representatives of state regulatory authorities serving on the Advisory Committee, which have been chosen by entities that regulate the retail electric or distribution rates of the Owners who are signatories to the Transmission Owners Agreement or (ii) representatives of public consumer groups serving on the Advisory Committee, which have been chosen by recognized consumer organizations having an interest in the activities of MISO.

MISO
MEMBERS BY SECTOR
(June 2015)

X. PUBLIC CONSUMER GROUPS [8] (Non-Members)

1. Alliance for Affordable Energy
2. Arkansas Consumer Utilities Rate Advocacy Division, AG Office
3. Illinois Citizens Utility Board
4. Indiana Office of Utility Consumer Counselor
5. Iowa Office of Consumer Advocate, AG Office
6. Michigan Citizens Against Rate Excess
7. Minnesota Antitrust & Utilities Division, AG Office
8. Minnesota Dept. of Commerce, Division of Energy Resources
9. Mississippi Public Utilities Staff
10. Missouri Office of the Public Counsel
11. Montana Consumer Counsel
12. Texas Office of Public Utility Counsel
13. Wisconsin Citizens Utility Board

[8] The entities comprising the public consumer groups on the Advisory Committee are not members of MISO; rather, they are (i) representatives of state regulatory authorities serving on the Advisory Committee, which have been chosen by entities that regulate the retail electric or distribution rates of the Owners who are signatories to the Transmission Owners Agreement or (ii) representatives of public consumer groups serving on the Advisory Committee, which have been chosen by recognized consumer organizations having an interest in the activities of MISO.

Attachment G

2009 NERC Long-Term Reliability Assessment
(selected)

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2009 Long-Term Reliability Assessment

2009-2018

to ensure the reliability of the bulk power system

October 2009

116-390 Village Blvd., Princeton, NJ 08540
609.452.8060 | 609.452.9550 fax
www.nerc.com

2009 Emerging Issues

Economic Recession

The economic recession that began in 2007 has become a major global recession and has had an indelible impact on the electric power industry. While there is currently substantial uncertainty on the time, rate, and breadth of an economic recovery in the coming years, it is certain that its eventual arrival may present risks and challenges to the bulk power system on several levels. Here, four issues are explored in greater detail:

1. Demand Forecast – *The recession has caused significant impacts in demand forecasts.*

2. Growth in Demand Response and Energy Efficiency Programs – *Economic difficulties that drive new business opportunities and incent new resource programs may drive steep increases in these programs (and accompanying reliance upon them) but vigilance will be required to ensure they are available when needed for reliability.*

3. Rapid Demand Growth after a Flat Period – *An economic recovery will occur (eventually), but it is uncertain when it will happen and how fast it will occur—if the economy recovers quickly, the bulk power system must be ready to balance supply and demand while maintaining bulk power system reliability.*

4. Infrastructure – *Project financing uncertainty—in addition to reduced revenues—may thwart necessary infrastructure investments and impair long-term reliability.*

Demand Forecasts

The recession that has taken place throughout North America affects electric demand to varying degrees, depending on the Region and customer base. Long-term effects (structural) of the current recession shall remain so that decline in short and long term load forecasts is likely. The contribution of the economic component is a significant factor in load forecasting. Typically, the electric use in North America closely tracks the performance of the Gross Domestic Product (GDP) along with Regional employment and income. The severity of the current recession, coupled with the uncertainty of when a recovery will be realized, renders near-term load estimates particularly suspect; however, data suggests in the first two to three year period, economic uncertainty will prevail, with a recovery pattern probably quite different from previous slowdowns when peak demand was less impacted than energy use.

Whether changes are either cyclical or structural, or both, demand forecasts are entering a new uncertain phase and close monitoring of the recession's influence on electric demand is recommended.

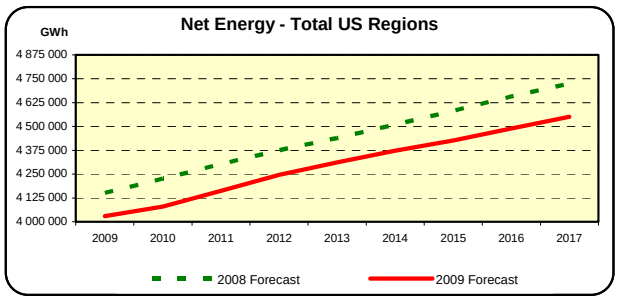
Background

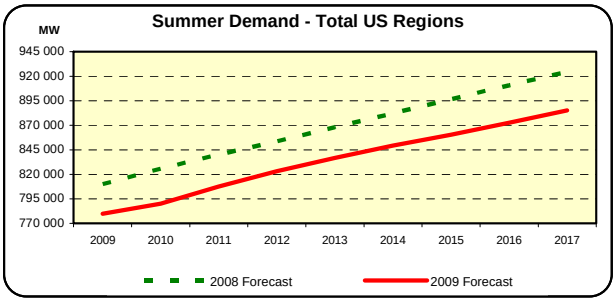
A severe economic recession has taken place throughout North America. Structural long-term effects of this recession are expected to remain, so a decline in short and long term load forecasts is likely. Accordingly, NERC's *2009 Long-Term Reliability Assessment* forecast shows that this

current recession impacts electric demand at varying degrees depending on the Region. Not all changes between 2008 and 2009 forecasts can be attributed to the economic recession.

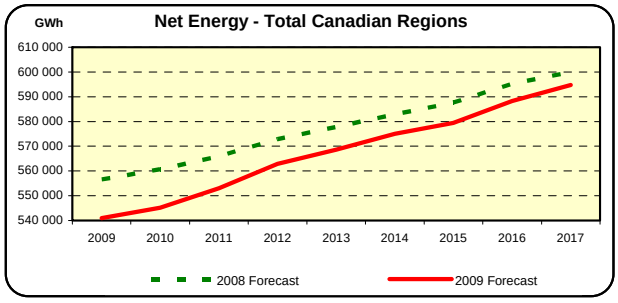
There is variation in the year-by-year path of each Region's forecast along with comparison to last year's forecast. All regions are impacted by the recession, but each in its own way.

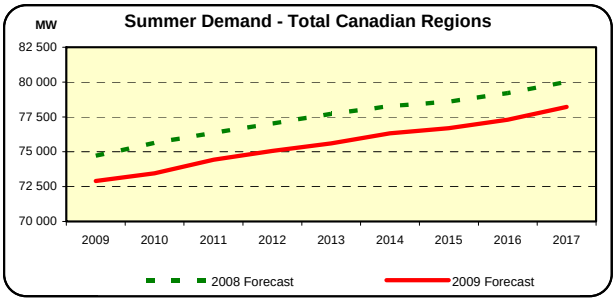
For the U.S., the 2009 forecasts include an average downward revision for the 2009-2017 timeframe of about -3.4 percent in terms of net energy level and -4.1 percent in terms of summer demand when compared to the 2008 forecast.



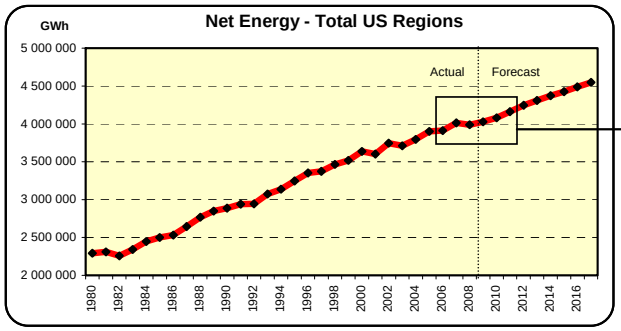


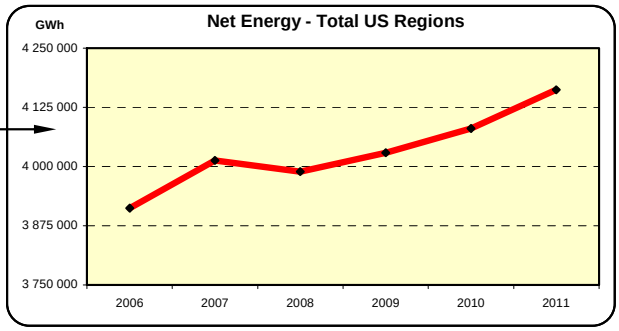
In Canada, this revision is about -1.8 percent (from -2.9 percent in 2009 to -0.9 percent in 2017) in energy and -2.6 percent in summer peak demand for 2017.

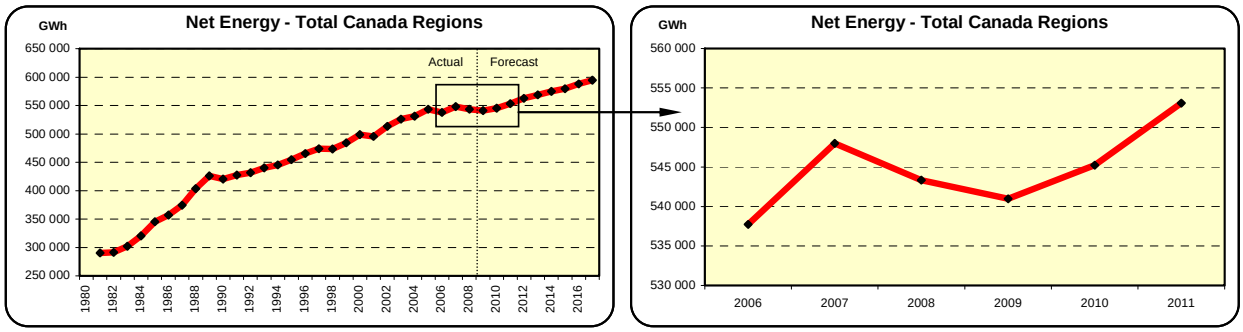




As anticipated, the 2009 forecast in this year's report includes the impact of a deep recession, while the recovery pattern is expected to be no different from previous recessions for both U.S. and Canada (as showed below merging historical data and this year's forecast, regions assume a recovery as soon as 2009 for the U.S. and 2010 for Canada).





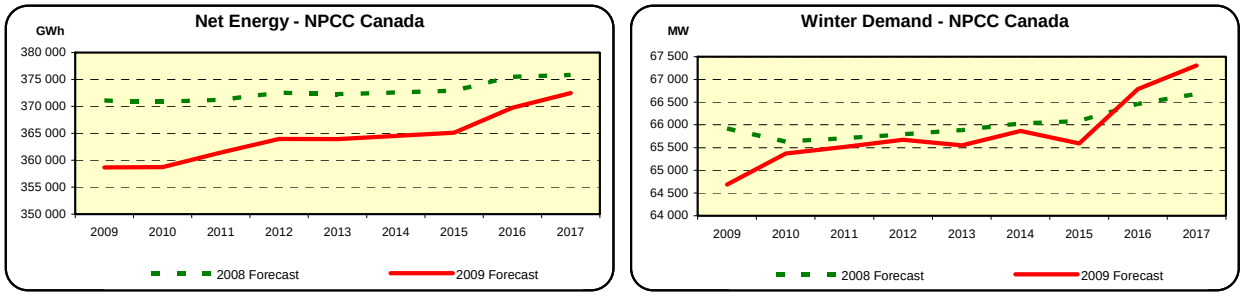


The analysis of the NERC Regional forecasts for this year's report also provides a good indicator on expected impacts within each geographical area. After reviewing individual results, some general conclusions can be drawn:

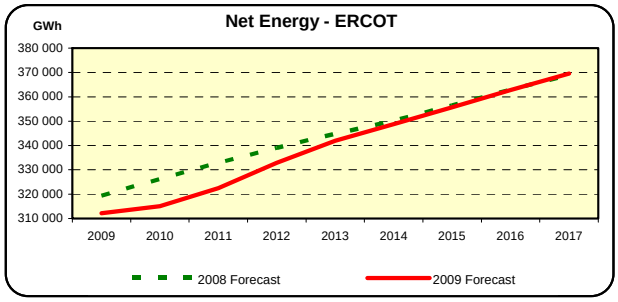
- There are significant differences among regions in terms of energy and peak demand impacts. More specifically, lower growth rates can generally be observed for each U.S. Region and slightly higher growth rates are however registered in Canada.
- Unlike first expectations, peak demand is affected more than energy, especially for U.S. winter and Canadian summer peaks.
- In terms of level, there is no sharp bounce back anticipated after the recession in any regions.

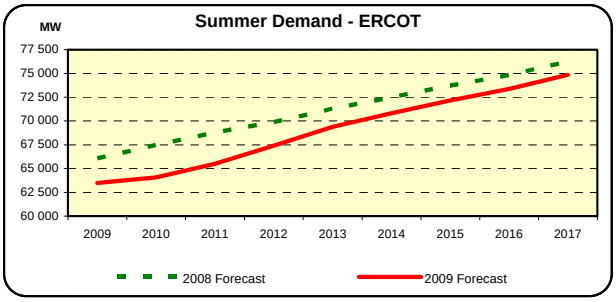
Several Regions and subregions with notable demand patterns are reviewed below.

- As shown before and despite a long and slow pattern, Canadian regions' forecasts tend to recover closer to the 2008 forecast level than the U.S. This is especially true for NPCC-Canada.

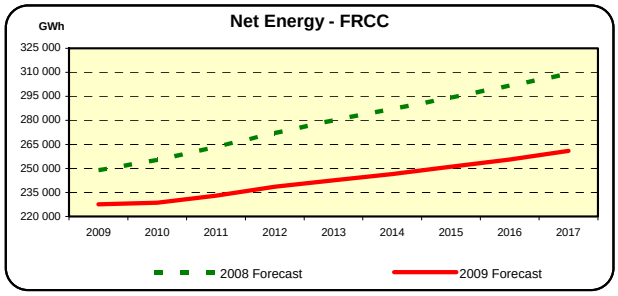


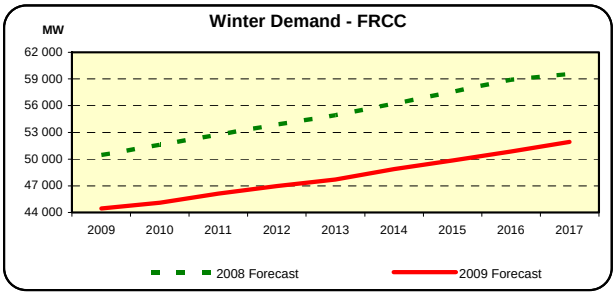
- This year's ERCOT forecast grows closer to the last year's than all other regions with a complete recovery in terms of energy level by the end of the 2009 to 2018 period. From 2009 to 2017, the average annual growth rate for the system peak of ERCOT's forecast last year was 1.8 percent and the growth rate this year is 2.1 percent. The higher eight-year growth rate in this year's forecast is fuelled by the projected strong recovery from the current economic recession reflected in the economic forecast in this Region after 2010.



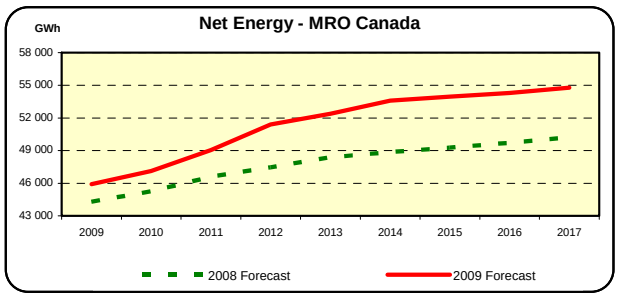


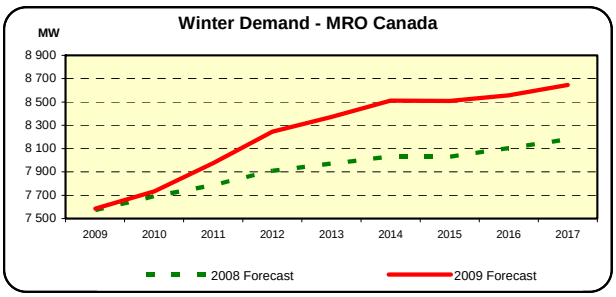
- Relative to the 2008 forecast, FRCC's forecast shows the largest decrease of all the regions with an expected net energy adjustment varying from -9.4 percent in 2009 to -18.4 percent in 2017. The summer peak forecast for this Region exhibits an average annual growth rate of 1.7 percent over the next eight years compared to last year's growth rate of 2.2 percent. This reduction is attributed to a decrease in economic development expectations in Florida along with an increase in demand side management coupled with expected higher electricity costs.





- There is a drop in energy and peak demand for all regions but one: the MRO Canada's new forecast is significantly higher than last year's and also grows much faster for the entire period, both in energy and in peak demand.





Conclusion

Whether cyclical and/or structural negatives result, demand forecasts are entering a new changing and uncertain phase and not all changes between this and last year's forecasts can be attributable to the current economic recession.

A recovery pattern not much different from previous slowdowns is anticipated by the majority of the regions. However, in the first two- or three-year period, major economic uncertainty will prevail. Additional uncertainty about deferral or cancellation of major industrial projects will not be easily quantifiable and will make both short and long term demand forecasting more challenging than in a steady economic growth cycle.

The current major economic recession has already negatively impacted the load forecast and will drive up short-term North American planning Reserve Margins. In the longer run, generation projects and transmission infrastructure investment may also be affected. A close and continuous monitoring of the recession, its impact and the economic recovery for all regions is recommended for the next few months.

Growth in Demand Response and Energy Efficiency Programs

Beyond cyclical or structural issues, peak demand and energy forecasting is becoming more challenging in an economic and legislative environment that encourages increased use of Demand Response (DR) and Energy Efficiency (EE) programs. Several U.S. states have mandated that certain levels of either DR or EE, or both be phased in over the next 5 to 10 years. In most cases, detailed plans for achieving these targets are yet to be developed. Planners must recognize this increased uncertainty in their reliability studies. An additional challenge is quantifying the impact of DR and particularly EE programs on peak-demand. EE programs target the reduction of energy use and the resulting impact on peak loads must be assessed to properly plan the electric power system.

Challenges related to DR forecasting include the need to develop accurate forecasts of:

- DR performance to ensure that adequate resources are installed to meet appropriate resource adequacy guidelines or standards.
- The aggregate amount of coincident reductions that can be obtained under varying weather conditions—if weather is actually the primary determinant of DR performance.
- The possible number of requests for customer response to DR signals. Such forecasts would allow for effective and informed decision making by potential demand-resource providers to provide these resources into the market.

The amount of DR and EE assumed in future years varies depending on different counting methods. The amount needs to recognize the DR and EE goals established by regulatory authorities but also needs to consider the likelihood of those goals being realized and their likely impact on peak demand. Inaccurate forecasts of peak demand due to uncertainty associated with future DR and EE programs can lead to several problems; failure to identify required facilities to maintain a reliable system, inadequate Reserve Margins, and transmission analyses failing to identify potential transmission reliability issues.

Depending on how aggressively demand resources are implemented and sustained in the NERC Regions, the penetration of these resources will provide many benefits, while, at the same time, bring many challenges. Efficiently integrating DR into the bulk power system while maintaining system reliability can challenge system planning processes, system and market operating processes, and electricity and computer hardware infrastructure. It also will require the development of effective integration methods that overcome some of the current challenges. Beyond the forecasting challenges of integrating large amounts of DR noted above, other challenges include the need to:

- Know the location of DR so that when activated, the response will have an expected outcome regarding operational metrics (voltage, line flows, etc.).
- Develop a reliable communications platform between the Balancing Authority Area operator and the DR providers to assure proper demand-response activations.
- Obtain accurate and descriptive performance data, using suitable definitions, to understand historical performance so that future performance can be estimated with a high degree of accuracy.
- Ensure that reliability is maintained without creating barriers to DR participation when there is a large penetration of DR resources in the bulk power system.

The NERC Demand Response Data Task Force is working to address some of these issues by working with stakeholders to develop better data collection procedures.

Rapid Demand Growth after Flat Period

As noted above, forecasting demand is difficult due to uncertainty in many of the input variables. Thus, no forecast can say with certainty how peak-demand and use will change over the coming years. A plausible demand growth projection involves flat to negative demand growth over the next 7 to 8 years followed by an abrupt change to normal or high demand growth. This type of situation is possible because of the uncertainty related to the confounded near-term effects of the economic slowdown, industrial load decline, increased conservation, Energy Efficiency (EE) increases, price-induced load reduction, and incentive-based demand reduction programs followed by a swift economic recovery and a waning impact over time for some demand-reducing programs.

The situation may include aggressive retirement of generation during the first 7 to 8 years, a consideration that generation manufacturing capacity would be idled during the low-growth period, and emission rules may be tightened in anticipation of continued low demand growth. As a result, generating capacity is retired to minimums only required for operational levels or required by regulation or markets. As future load is expected to be flat or low-growth, surplus generation is expected to have little possibility of future value and inhibit adequate investment.

The result of this demand growth pattern and generation changes may result in supply and demand balances that deteriorate quickly in the latter years of such a situation. Reliability can rapidly deteriorate in the last years of the planning horizon as demand increases rapidly and generation cannot be constructed quickly enough to respond.

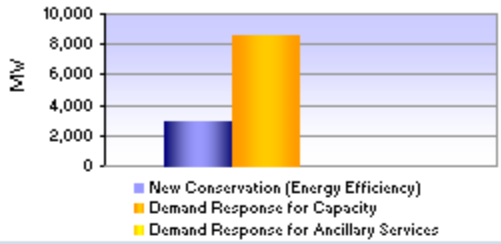
Future studies of this situation include modeling low load growth with tight reserves no later than 7 years out followed by rapid growth with little ability to respond within the time horizon. This situation can illustrate the need to keep adequate generating reserves in case of load growth even if it is considered a low probability event.

SERC

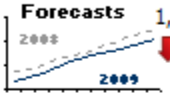
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	202,738	237,386
Direct Control Load Management	972	3,023
Contractually Interruptible (Curtailable)	4,624	5,200
Critical Peak-Pricing with Control	0	41
Load as a Capacity Resource	271	260
Net Internal Demand (MW)	196,871	228,862

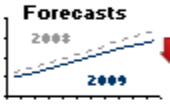
Demand-Side Management - 2018



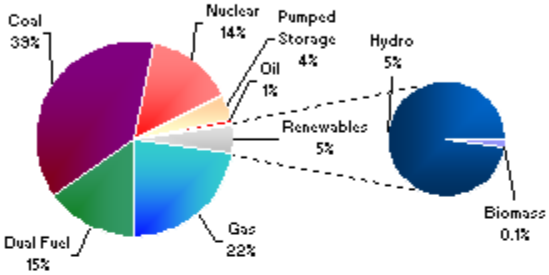
Energy Consumption	2009	2017
Net Energy to Load (GWh)	1,039,997	1,192,039
Percentage Change from 2008 Forecast	-4.3%	-3.3%



Peak Demand Comparison	2009	2017
2008 Demand Forecast	209,288	243,056
Percentage Change from 2008 Forecast	-3.1%	-3.8%



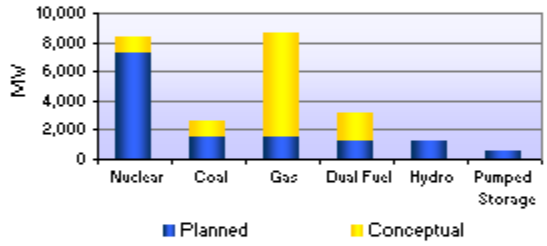
Relative Capacity Mix by Fuel Type - 2009



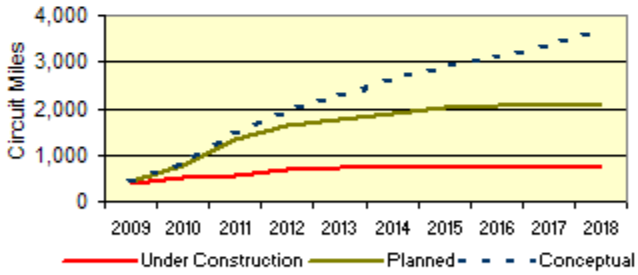
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	242,787	23.3%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	262,372	14.6%
Prospective Capacity Resources	276,673	20.9%
Adjusted Potential Capacity Resources	276,748	20.9%
Total Potential Capacity Resources	290,774	27.1%
NERC Reference Margin Level	-	15.0%

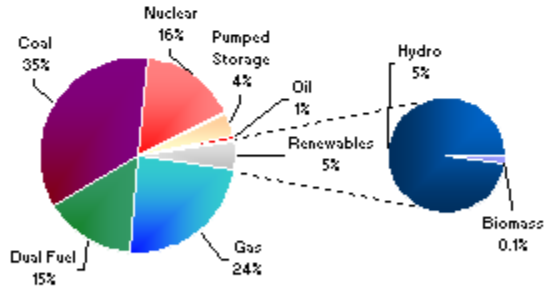
Projected On-Peak Fuel-Mix 10 Year Change



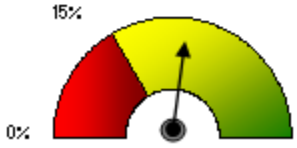
Projected Transmission Additions



Relative Capacity Mix by Fuel Type - 2018

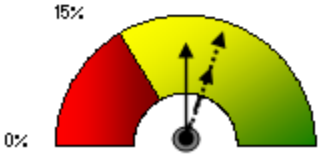


2009 Reserve Margin



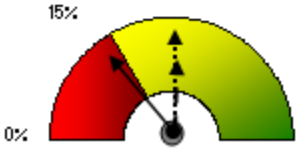
Existing-Certain & Net Firm Transactions

2013 Reserve Margins



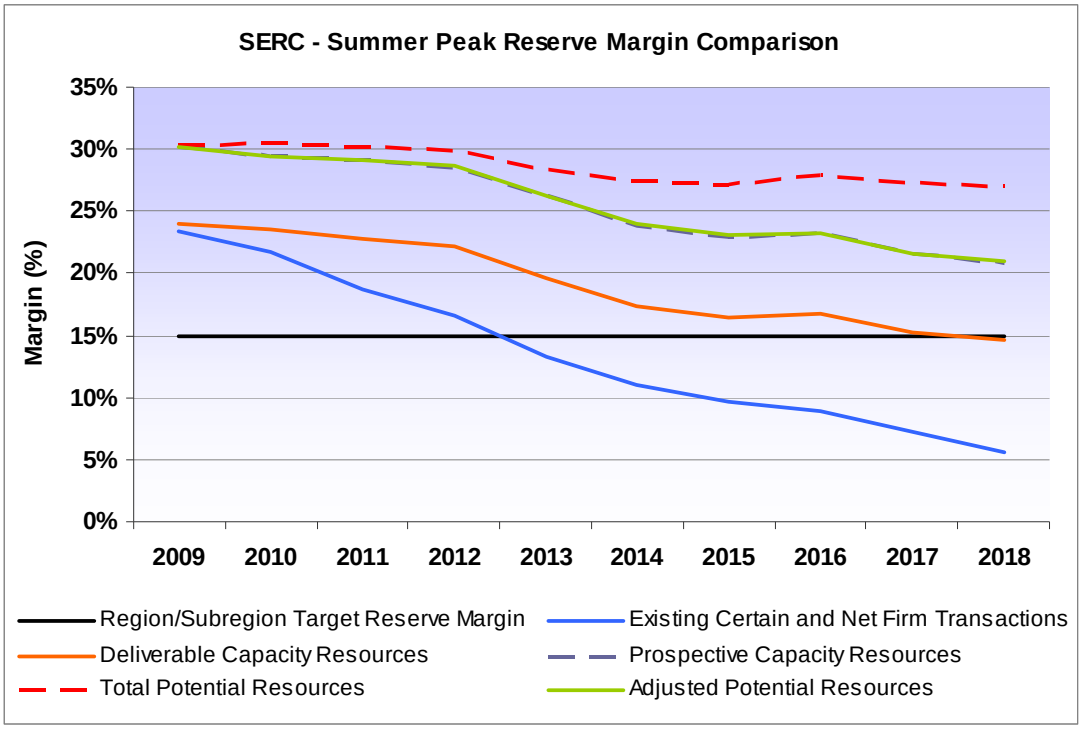
Deliverable
Prospective
Adjusted Potential

2018 Reserve Margins

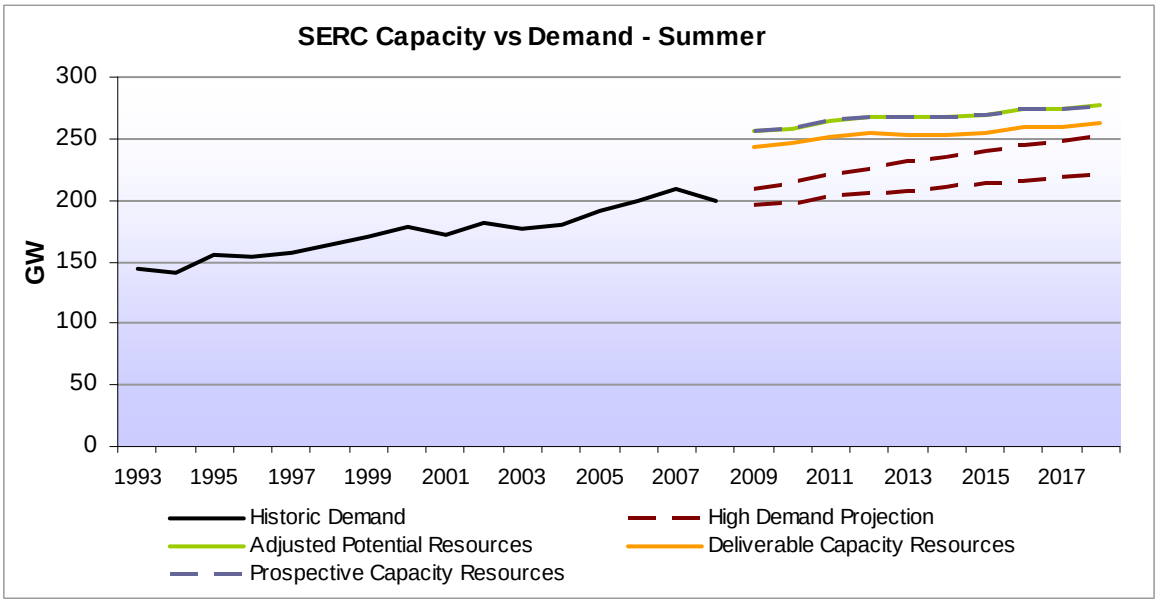


Deliverable
Prospective
Adjusted Potential

For the 2009 to 2018 assessment period, SERC Reserve Margins are projected to fall below the NERC Reference Margin Level by 2013 if no new resources are added. With the addition of Future resources, the reserve margins appear to be higher than the NERC Reference Margin Level, but tight in 2018.

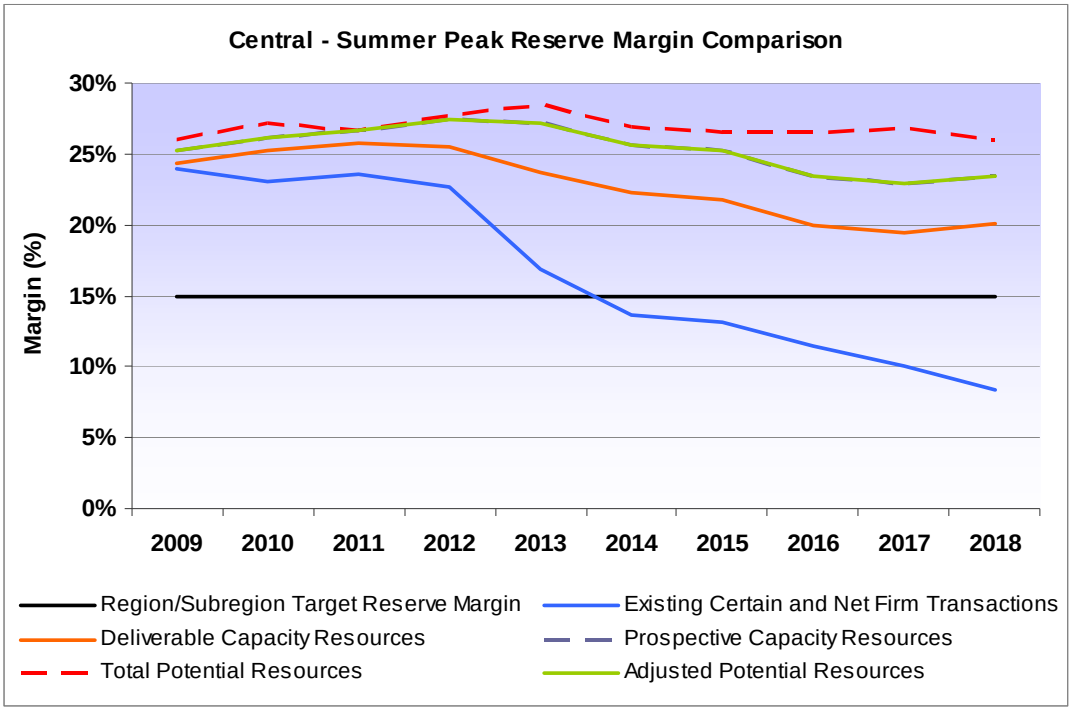


For the high demand projection[114], SERC capacity resources, with all categories considered, are projected to remain above the NERC Reference Margin Level through 2018.

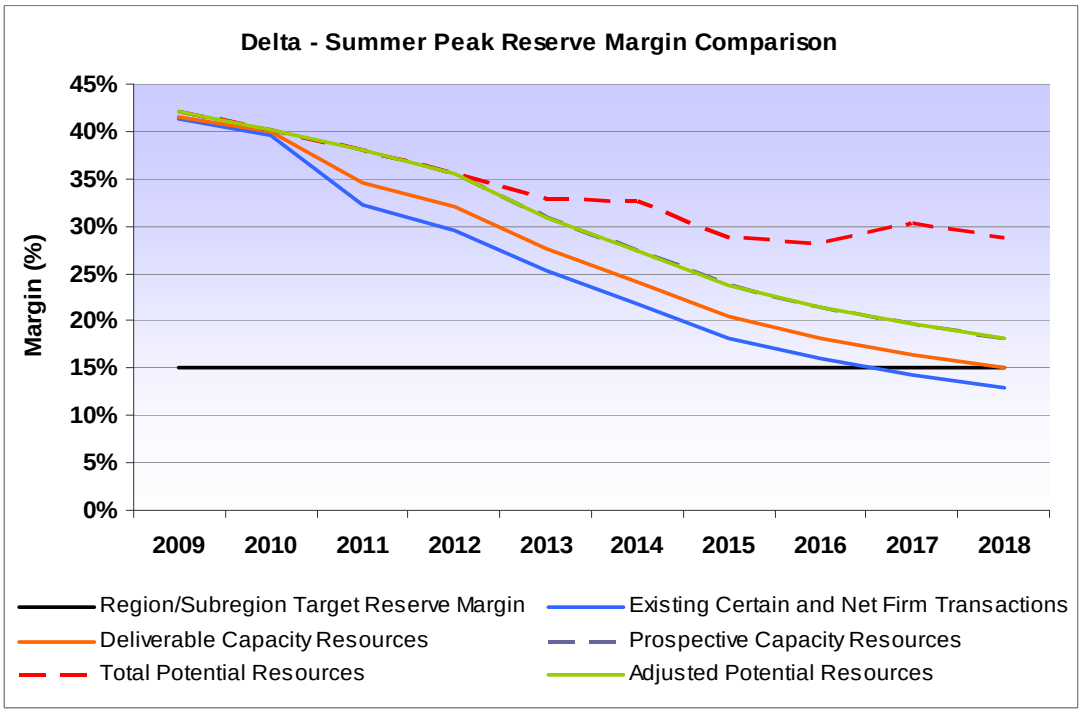


[114] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

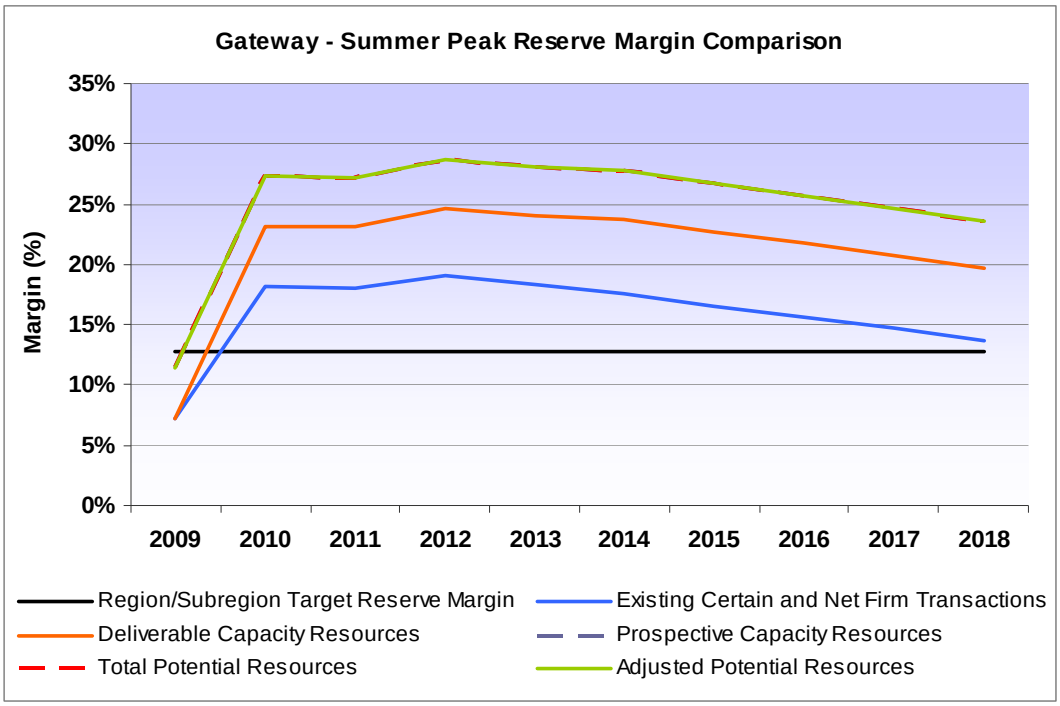
For the 2009 to 2018 assessment period, SERC-Central Reserve Margins are projected below the NERC Reference Margin Level by 2014 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.



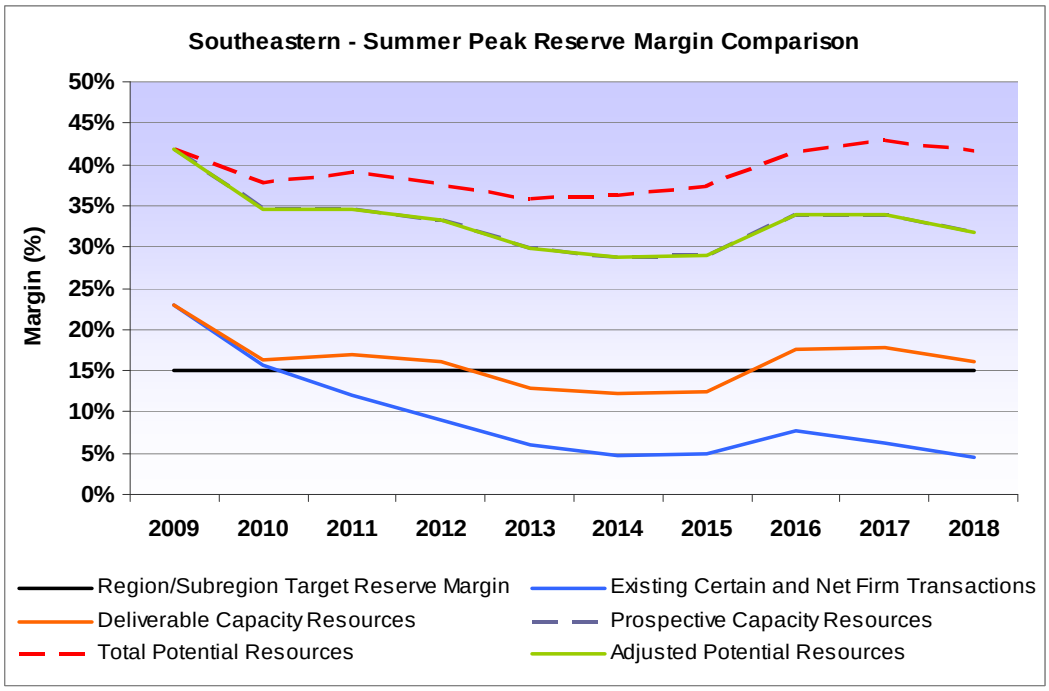
For the 2009 to 2018 assessment period, SERC-Delta Reserve Margins are projected below the NERC Reference Margin Level by 2017 if no new resources are added. With the addition of Future resources, the reserve margins should remain above the NERC Reference Margin Level.



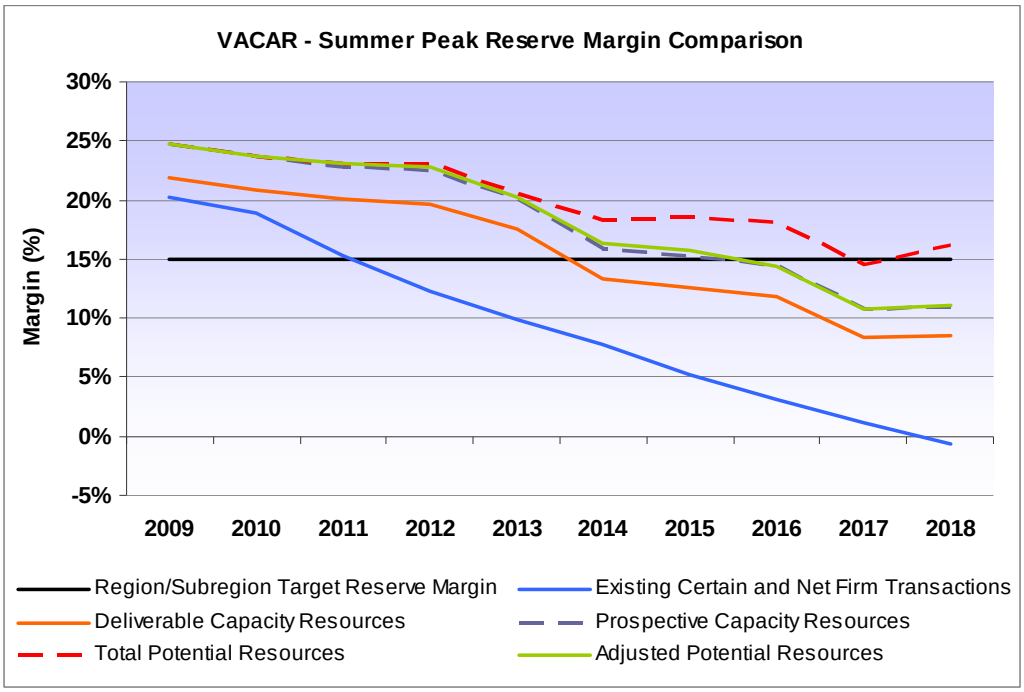
For the 2009 to 2018 assessment period, SERC-Gateway Reserve Margins are below the NERC Reference Margin Level for 2009. However, by 2010, all Reserve Margins are projected to remain above the NERC Reference Margin Level through 2018.



For the 2009 to 2018 assessment period, SERC-Southeastern Reserve Margins are projected below the NERC Reference Margin Level by 2011, if no new resources are added. Reserve Margins should be increased with the addition of Future resources through 2018.



For the 2009 to 2018 assessment period, SERC-VACAR Reserve Margins are projected below the NERC Reference Margin Level by 2012 if no new resources are added. Even with the addition of all Future resources, reserve margins are below the NERC Reference Margin Level, projected by 2016. SERC-VACAR may need the additional resources to remain above the NERC Reference Margin Level through 2018.



SPP Highlights

The SPP RTO Region is anticipating a steady and slow growth in demand with total system demand approaching 50,000 MW by 2018. Current SPP RTO demand is 44,500 MW.

The annual reserve margin for SPP is greater than the required 13.6 percent until the year 2016, where the margin drops to approximately 13 percent. For the remaining years (i.e., 2017 and 2018), SPP anticipates to meet reserve margin using potential capacity resources.

The SPP Transmission Expansion Plan 2009-2018 reported approximately 1,000 miles of bulk transmission lines and more than 10 transformers to address reliability needs. The SPP RC anticipates that the Acadiana Load Pocket will be a concern for the remainder of the 2009 summer. SPP is working with each entity in the area to resolve the issues and protect the load in the area. As a long-term solution, the SPP Independent Coordinator of Transmission (ICT) facilitated an agreement with members in the Acadiana pocket to expand and upgrade electric transmission in the area. In addition to the reliability needs, SPP RTO has implemented a Balanced Portfolio, which is a strategic initiative to develop a cohesive group of economic upgrades that benefit the SPP RTO Region, and for which costs will be allocated Regionally. Projects in the Balanced Portfolio are transmission upgrades of 345 kV or higher that will provide customers with potential savings that exceed the cost of the project. In April 2009, the SPP Regional State Committee and the Board of Directors/Members Committee approved Balance Portfolio projects totaling over $700 million, to be funded by the application of Federal Energy Regulatory Commission-approved “postage stamp” rates to SPP’s transmission-owning members across the Region.

The SPP Board of Directors recently approved the adoption of new planning principles and implementation of an Integrated Transmission Planning (ITP) Process. The ITP will consolidate SPP’s EHV Overlay, Balanced Portfolio, and ten-year reliability assessment into one consolidated process.

SPP as a Planning Authority conducts various reliability assessments to comply with NERC TPL Reliability Standards and coordinate the mitigation effort with its members. Based on the studies performed, SPP is not anticipating any near- or long-term reliability issues that have not addressed by any mitigation plan or local operating guides.

Since the implementation of the EIS market in 2007, SPP RTO continues an increase in the number of TLR events primarily due to the fact that SPP publishes congested facilities by issuing TLRs. SPP’s tariff and market protocols require the SPP RC to issue a TLR event in accordance with NERC TLR requirements each time congestion is experienced in the market footprint, even when it is only constraining economic use of transmission. SPP’s market protocols require issuing a TLR to announce that SPP is experiencing congestion.

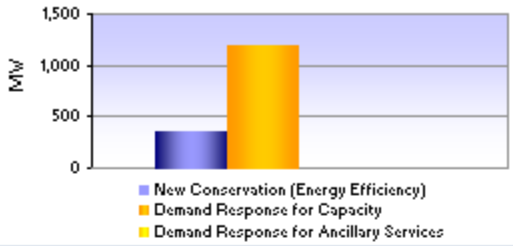
The penetration of wind generation in the western half of the SPP footprint is anticipated to have a significant impact on operations, due to wind's variable nature. SPP RTO currently has approximately 50,000 MW of wind in their Generation Interconnection queue. Additional data collection and situational awareness has been implemented to begin assessing regulation and spinning reserve needs. SPP formed a Wind Integration Task Force, which is responsible for conducting and reviewing studies to determine the impact of integrating wind generation into the SPP RTO transmission system and energy markets. These studies will include both planning and operational issues. The studies should lead to recommendations for developing new tools that may be required for the SPP RTO to properly evaluate requests for interconnecting wind generating resources to the transmission system.

SPP

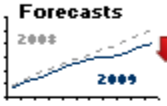
Regional Long-Term Assessment Summary

Summer Peak Demand	2009	2018
Total Internal Demand (MW)	44,463	49,696
Direct Control Load Management	33	30
Contractually Interruptible (Curtailable)	484	527
Critical Peak-Pricing with Control	35	324
Load as a Capacity Resource	215	315
Net Internal Demand (MW)	43,696	48,500

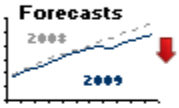
Demand-Side Management - 2018



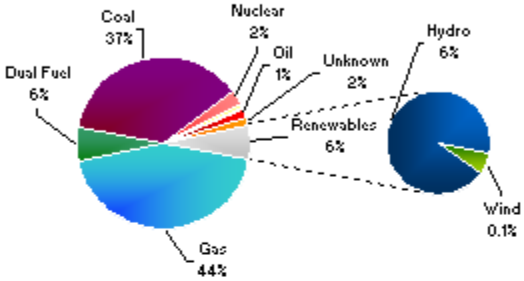
Energy Consumption	2009	2017
Net Energy to Load (GWh)	211,320	236,886
Percentage Change from 2008 Forecast	-0.7%	-3.9%



Peak Demand Comparison	2009	2017
2008 Demand Forecast	44,786	50,640
Percentage Change from 2008 Forecast	-0.7%	-3.2%



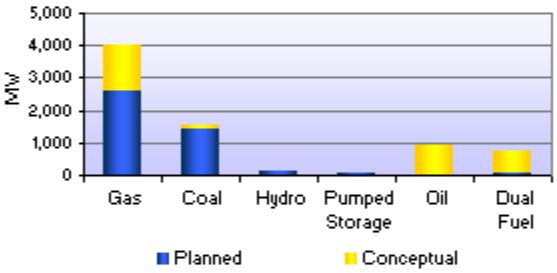
Relative Capacity Mix by Fuel Type - 2009



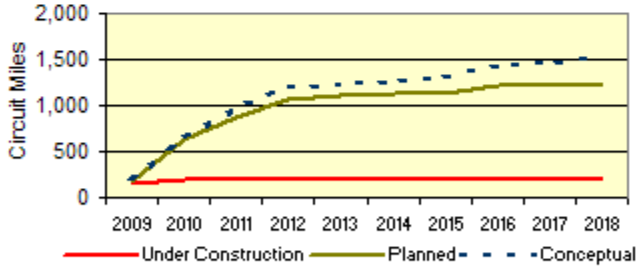
Capacity Resources On-Peak - 2009	MW	Margin
Existing Certain and Net Firm Transactions	49,706	13.8%

Capacity Resources On-Peak - 2018	MW	Margin
Deliverable Capacity Resources	53,319	9.9%
Prospective Capacity Resources	59,846	23.4%
Adjusted Potential Capacity Resources	60,141	24.0%
Total Potential Capacity Resources	65,880	35.8%
NERC Reference Margin Level	-	13.6%

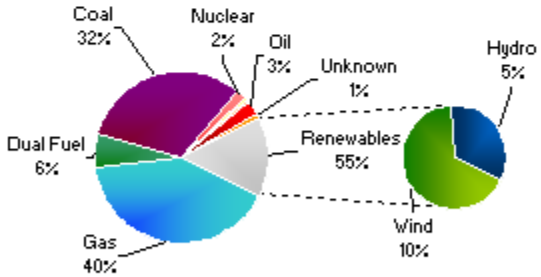
Projected On-Peak Fuel-Mix 10 Year Change



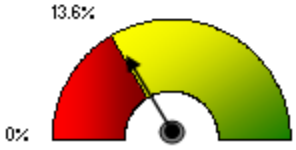
Projected Transmission Additions



Relative Capacity Mix by Fuel Type - 2018

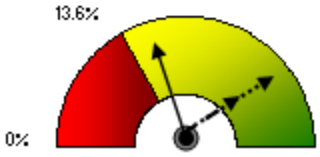


2009 Reserve Margin



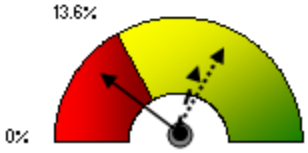
Existing-Certain & Net Firm Transactions →

2013 Reserve Margins



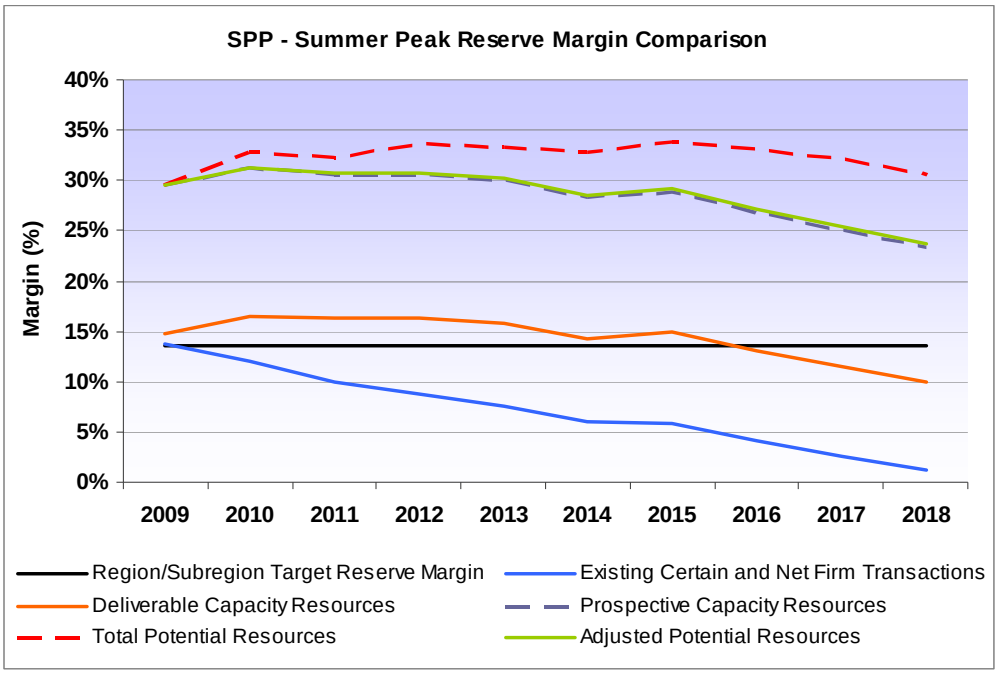
Deliverable →
Prospective - - - →
Adjusted Potential ····→

2018 Reserve Mar

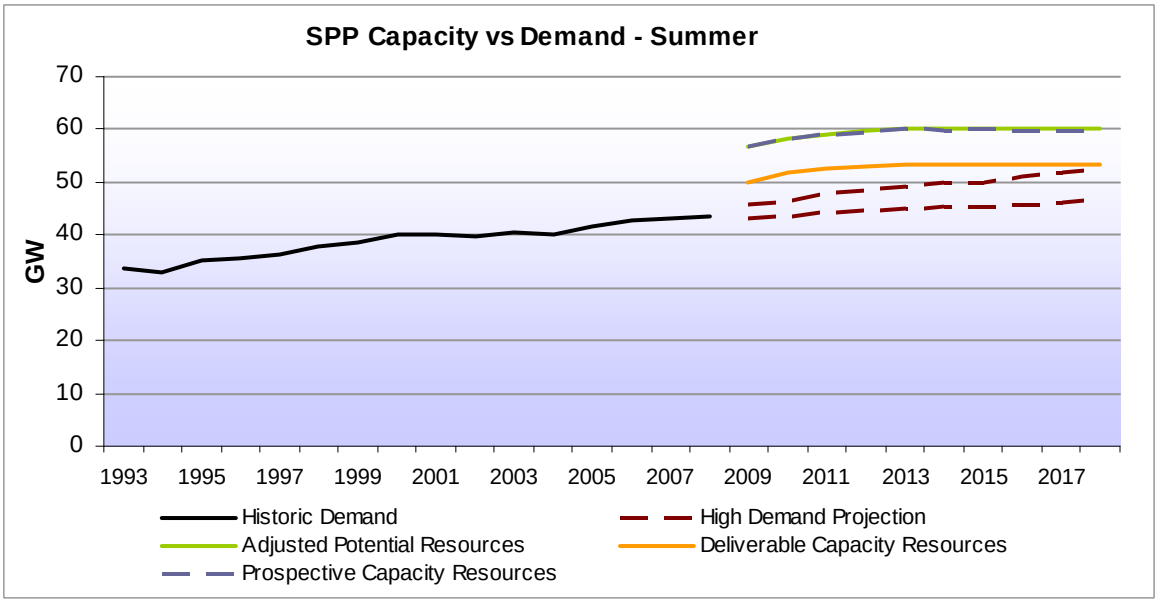


Deliverable →
Prospective - - - →
Adjusted Potential ····→

For the 2009 to 2018 assessment period, SPP Reserve Margins are projected below the NERC Reference Margin Level by 2010 if no new resources are added. Even with the addition of Future, Planned resources, Reserve Margins are below the NERC Reference Margin Level by 2016. SPP may need the additional resources to remain above the NERC Reference Margin Level through 2018.



For the high demand projection,[115] SPP capacity resources, with all categories considered, remain higher than these forecasts through 2018.



[115] Demand uncertainty bandwidths represent a 10% chance of falling above and 10% chance of falling below confidence bands.

Table Margins 2a: Estimated 2009 Summer Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Transactions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Transactions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	63,491	62,376	72,204	72,204	72,204	72,204	72,204	15.8%	15.8%	15.8%	15.8%	15.8%	12.5%
FRCC	45,734	42,531	49,239	51,870	51,870	51,870	53,210	15.8%	22.0%	22.0%	22.0%	25.1%	15.0%
MRO	44,206	41,306	49,648	50,308	50,316	51,098	52,925	20.2%	21.8%	21.8%	23.7%	28.1%	15.0%
NPCC	61,327	61,108	73,678	76,671	76,889	77,579	77,647	20.6%	25.5%	25.8%	27.0%	27.1%	15.0%
New England	27,875	27,875	33,475	33,703	33,921	33,921	33,989	20.1%	20.9%	21.7%	21.7%	21.9%	15.0%
New York	33,452	33,233	40,203	42,968	42,968	43,658	43,658	21.0%	29.3%	29.3%	31.4%	31.4%	16.5%
RFC	178,100	169,900	215,700	215,800	217,600	217,904	219,200	27.0%	27.0%	28.1%	28.3%	29.0%	15.0%
RFC-MISO	62,419	60,719	70,714	70,714	72,308	72,308	72,308	16.5%	16.5%	19.1%	19.1%	19.1%	15.4%
RFC-PJM	116,153	109,653	144,837	144,939	145,113	145,422	146,740	32.1%	32.2%	32.3%	32.6%	33.8%	15.0%
SERC	202,738	196,871	242,787	244,008	256,129	256,129	256,433	23.3%	23.9%	30.1%	30.1%	30.3%	15.0%
Central	42,733	40,874	50,660	50,828	51,196	51,196	51,500	23.9%	24.4%	25.3%	25.3%	26.0%	15.0%
Delta	27,865	27,178	38,433	38,466	38,602	38,602	38,602	41.4%	41.5%	42.0%	42.0%	42.0%	15.0%
Gateway	19,065	18,947	20,306	20,306	21,117	21,117	21,117	7.2%	7.2%	11.5%	11.5%	11.5%	12.7%
Southeastern	49,504	47,789	58,745	58,745	67,788	67,788	67,788	22.9%	22.9%	41.8%	41.8%	41.8%	15.0%
VACAR	63,571	62,083	74,643	75,663	77,426	77,426	77,426	20.2%	21.9%	24.7%	24.7%	24.7%	15.0%
SPP	44,463	43,696	49,706	50,127	56,619	56,648	57,206	13.8%	14.7%	29.6%	29.6%	30.9%	13.6%
WECC	140,692	136,441	172,375	174,978	174,978	174,980	174,985	26.3%	28.2%	28.2%	28.2%	28.2%	17.9%
AZ-NM-SNV	30,452	29,843	35,156	35,076	35,076	35,076	35,077	17.8%	17.5%	17.5%	17.5%	17.5%	17.8%
CA-MX US	61,237	58,421	71,447	71,334	71,334	71,334	71,334	22.3%	22.1%	22.1%	22.1%	22.1%	22.3%
NWPP	39,754	39,155	56,001	57,340	57,340	57,342	57,346	43.0%	46.4%	46.4%	46.4%	46.5%	16.3%
RMPA	11,224	10,939	12,815	13,517	13,517	13,517	13,517	17.1%	23.6%	23.6%	23.6%	23.6%	17.1%
Total-U.S.	780,751	754,229	925,336	935,965	956,605	958,413	963,810	22.7%	24.1%	26.8%	27.1%	27.8%	15.0%
Canada													
MRO	6,369	6,082	7,372	7,372	7,372	7,385	7,414	21.2%	21.2%	21.2%	21.4%	21.9%	10.0%
NPCC	48,471	48,026	65,078	66,855	67,456	67,456	67,456	35.5%	39.2%	40.5%	40.5%	40.5%	15.0%
Maritimes	3,499	3,054	5,987	5,987	5,987	5,987	5,987	96.0%	96.0%	96.0%	96.0%	96.0%	20.0%
Ontario	24,351	24,351	28,011	29,788	30,410	30,410	30,410	15.0%	22.3%	24.9%	24.9%	24.9%	17.5%
Quebec	20,621	20,621	31,080	31,080	31,059	31,059	31,059	50.7%	50.7%	50.6%	50.6%	50.6%	9.7%
WECC	18,071	18,071	22,099	22,277	22,277	22,277	22,370	22.3%	23.3%	23.3%	23.3%	23.8%	12.5%
Total-Canada	72,911	72,179	94,549	96,504	97,105	97,118	97,240	31.0%	33.7%	34.5%	34.6%	34.7%	10.0%
Mexico													
WECC CA-MX Mex	2,115	2,115	2,446	2,446	2,446	2,446	2,446	15.7%	15.7%	15.7%	15.7%	15.7%	15.6%
Total-NERC	855,777	828,523	1,022,331	1,034,915	1,056,156	1,057,976	1,063,496	23.4%	24.9%	27.5%	27.7%	28.4%	15.0%

Table Margins 2b: Estimated 2009/10 Winter Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	43,463	42,348	73,916	74,797	74,797	74,797	74,797	74.5%	76.6%	76.6%	76.6%	76.6%	12.5%
FRCC	44,446	40,846	52,751	57,216	57,216	57,216	58,556	29.1%	40.1%	40.1%	40.1%	43.4%	15.0%
MRO	36,904	34,985	48,104	48,417	49,165	49,948	51,774	37.5%	38.4%	40.5%	42.8%	48.0%	15.0%
NPCC	47,098	47,098	76,849	77,577	78,092	78,092	78,561	63.2%	64.7%	65.8%	65.8%	66.8%	15.0%
New England	22,100	22,100	36,210	36,545	37,060	37,060	37,529	63.8%	65.4%	67.7%	67.7%	69.8%	15.0%
New York	24,998	24,998	40,639	41,032	41,032	41,032	41,032	62.6%	64.1%	64.1%	64.1%	64.1%	16.5%
RFC	145,800	140,900	218,000	218,100	219,800	220,104	221,400	54.7%	54.8%	56.0%	56.2%	57.1%	15.0%
RFC-MISO	49,051	47,426	70,714	70,714	72,308	72,308	72,308	49.1%	49.1%	52.5%	52.5%	52.5%	15.4%
RFC-PJM	96,644	93,395	144,837	144,939	145,113	145,422	146,740	55.1%	55.2%	55.4%	55.7%	57.1%	15.0%
SERC	181,045	175,541	248,673	251,192	263,272	263,272	263,701	41.7%	43.1%	50.0%	50.0%	50.2%	15.0%
Central	42,240	40,636	52,618	52,785	53,204	53,204	53,207	29.5%	29.9%	30.9%	30.9%	30.9%	15.0%
Delta	23,023	22,501	40,674	40,707	40,862	40,862	40,862	80.8%	80.9%	81.6%	81.6%	81.6%	15.0%
Gateway	15,696	15,608	21,219	22,084	22,554	22,554	22,554	35.9%	41.5%	44.5%	44.5%	44.5%	12.7%
Southeastern	41,869	40,147	57,450	57,800	66,884	66,884	67,310	43.1%	44.0%	66.6%	66.6%	67.7%	15.0%
VACAR	58,217	56,649	76,712	77,816	79,768	79,768	79,768	35.4%	37.4%	40.8%	40.8%	40.8%	15.0%
SPP	32,636	31,988	49,112	49,535	55,949	55,978	56,536	53.5%	54.9%	74.9%	75.0%	76.7%	13.6%
WECC	111,324	108,535	168,290	173,502	173,502	173,504	173,509	55.1%	59.9%	59.9%	59.9%	59.9%	16.7%
AZ-NM-SNV	18,868	18,176	38,089	38,775	38,775	38,775	38,777	109.6%	113.3%	113.3%	113.3%	113.3%	15.5%
CA-MX US	41,922	40,029	60,278	63,393	63,393	63,393	63,393	50.6%	58.4%	58.4%	58.4%	58.4%	15.9%
NWPP	41,681	41,391	55,850	56,705	56,705	56,710	56,720	34.9%	37.0%	37.0%	37.0%	37.0%	18.4%
RMPA	9,658	9,479	13,712	14,811	14,811	14,811	14,811	44.7%	56.3%	56.3%	56.3%	56.3%	15.4%
Total-U.S.	642,716	622,241	935,694	950,335	971,792	972,910	978,834	50.4%	52.7%	56.2%	56.4%	57.3%	15.0%
Canada													
MRO	7,620	7,332	8,715	8,914	8,881	8,894	8,923	18.9%	21.6%	21.1%	21.3%	21.7%	10.0%
NPCC	64,690	62,499	72,293	75,173	75,789	75,789	75,789	15.7%	20.3%	21.3%	21.3%	21.3%	15.0%
Maritimes	5,554	5,113	6,118	6,887	6,887	6,887	6,887	19.7%	34.7%	34.7%	34.7%	34.7%	20.0%
Ontario	22,886	22,886	26,028	28,104	28,741	28,741	28,741	13.7%	22.8%	25.6%	25.6%	25.6%	17.5%
Quebec	36,250	34,500	40,147	40,182	40,161	40,161	40,161	16.4%	16.5%	16.4%	16.4%	16.4%	10.4%
WECC	21,548	21,548	24,389	24,513	24,513	24,513	24,888	13.2%	13.8%	13.8%	13.8%	15.5%	12.5%
Total-Canada	93,858	91,379	105,397	108,600	109,183	109,195	109,600	15.3%	18.8%	19.5%	19.5%	19.9%	10.0%
Mexico													
WECC CA-MX Mex	1,480	1,480	1,930	1,930	1,930	1,930	1,930	30.4%	30.4%	30.4%	30.4%	30.4%	10.1%
Total-NERC	738,054	715,100	1,043,022	1,060,866	1,082,905	1,084,036	1,090,364	45.9%	48.4%	51.4%	51.6%	52.5%	15.0%

Table Margins 2c: Estimated 2013 Summer Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	69,399	68,284	72,204	79,521	79,521	84,617	105,000	5.7%	16.5%	16.5%	23.9%	53.8%	12.5%
FRCC	48,304	44,697	49,330	57,464	57,464	57,464	58,811	10.4%	28.6%	28.6%	28.6%	31.6%	15.0%
MRO	47,500	44,482	49,159	50,218	50,309	54,299	63,612	10.5%	12.9%	13.1%	22.1%	43.0%	15.0%
NPCC	63,445	63,226	73,223	78,207	78,426	78,683	92,524	15.8%	23.7%	24.0%	24.4%	46.3%	15.0%
New England	29,365	29,365	33,478	34,827	35,045	37,122	45,694	14.0%	18.6%	19.3%	26.4%	55.6%	15.0%
New York	34,080	33,861	39,746	43,381	43,381	43,957	46,830	17.4%	28.1%	28.1%	29.8%	38.3%	16.5%
RFC	192,100	183,900	214,000	219,600	221,300	228,502	259,700	16.4%	19.4%	20.3%	24.3%	41.2%	15.0%
RFC-MISO	64,924	63,224	70,714	71,138	72,732	73,544	76,953	11.8%	12.5%	15.0%	16.3%	21.7%	15.4%
RFC-PJM	127,079	120,579	142,022	147,228	147,319	153,732	181,458	17.8%	22.1%	22.2%	27.5%	50.5%	16.2%
SERC	219,712	211,900	240,012	253,404	267,483	267,583	271,933	13.3%	19.6%	26.2%	26.3%	28.3%	15.0%
Central	45,345	42,437	49,607	52,473	53,990	53,990	54,516	16.9%	23.6%	27.2%	27.2%	28.5%	15.0%
Delta	30,187	29,406	36,823	37,499	38,505	38,505	39,043	25.2%	27.5%	30.9%	30.9%	32.8%	15.0%
Gateway	20,144	20,032	23,707	24,834	25,645	25,645	25,645	18.3%	24.0%	28.0%	28.0%	28.0%	12.7%
Southeastern	55,018	53,099	56,306	59,987	68,949	68,949	72,105	6.0%	13.0%	29.8%	29.8%	35.8%	15.0%
VACAR	69,018	66,926	73,569	78,611	80,394	80,494	80,624	9.9%	17.5%	20.1%	20.3%	20.5%	15.0%
SPP	47,255	46,153	49,602	53,477	60,001	60,149	63,067	7.5%	15.9%	30.0%	30.3%	36.6%	13.6%
WECC	150,163	143,988	172,192	204,058	204,058	205,307	207,579	19.6%	41.7%	41.7%	42.6%	44.2%	17.9%
AZ-NM-SNV	32,897	32,060	36,512	39,157	39,157	39,663	41,072	13.9%	22.1%	22.1%	23.7%	28.1%	17.8%
CA-MX US	64,493	60,073	71,622	89,293	89,293	89,293	89,355	19.2%	48.6%	48.6%	48.6%	48.7%	22.3%
NWPP	42,942	42,117	50,768	61,577	61,577	61,664	62,074	20.5%	46.2%	46.2%	46.4%	47.4%	16.3%
RMPA	12,015	11,616	13,853	14,483	14,483	15,131	15,514	19.3%	24.7%	24.7%	30.3%	33.6%	17.1%
Total-U.S.	837,878	806,630	919,722	995,948	1,018,561	1,036,603	1,122,225	14.0%	23.5%	26.3%	28.5%	39.1%	15.0%
Canada													
MRO	7,086	6,826	7,617	8,414	8,414	8,735	9,482	11.6%	23.3%	23.3%	28.0%	38.9%	10.0%
NPCC	48,594	48,154	64,281	73,200	72,974	72,974	73,757	33.5%	52.0%	51.5%	51.5%	53.2%	15.0%
Maritimes	3,502	3,062	6,135	6,948	6,948	6,948	6,948	100.4%	126.9%	126.9%	126.9%	126.9%	20.0%
Ontario	23,092	23,092	26,467	33,410	33,205	33,988	33,988	14.6%	44.7%	43.8%	47.2%	47.2%	19.1%
Quebec	22,000	22,000	31,679	32,842	32,821	32,821	32,821	44.0%	49.3%	49.2%	49.2%	49.2%	11.7%
WECC	19,927	19,927	22,079	23,053	23,053	24,238	26,440	10.8%	15.7%	15.7%	21.6%	32.7%	12.5%
Total-Canada	75,608	74,908	93,977	104,668	104,441	105,947	109,680	25.5%	39.7%	39.4%	41.4%	46.4%	10.0%
Mexico													
WECC CA-MX Mex	2,345	2,345	2,287	2,713	2,713	3,026	3,026	-2.5%	15.7%	15.7%	29.0%	29.0%	15.6%
Total-NERC	915,830	883,882	1,015,986	1,103,329	1,125,715	1,145,577	1,234,931	14.9%	24.8%	27.4%	29.6%	39.7%	15.0%

Table Margins 2d: Estimated 2013/14 Winter Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	47,984	46,869	73,916	81,233	81,233	81,233	106,829	57.7%	73.3%	73.3%	73.3%	127.9%	12.5%
FRCC	47,709	43,813	52,827	62,001	62,001	62,001	63,349	20.6%	41.5%	41.5%	41.5%	44.6%	15.0%
MRO	39,107	37,119	48,197	49,299	50,102	54,092	63,405	29.8%	32.8%	35.0%	45.7%	70.8%	15.0%
NPCC	47,620	47,620	74,107	76,768	77,324	77,324	91,703	55.6%	61.2%	62.4%	62.4%	92.6%	15.0%
New England	22,335	22,335	33,926	35,350	35,906	38,009	46,616	51.9%	58.3%	60.8%	70.2%	108.7%	15.0%
New York	25,285	25,285	40,181	41,418	41,418	41,785	45,087	58.9%	63.8%	63.8%	65.3%	78.3%	16.5%
RFC	155,100	150,200	216,300	221,900	223,600	230,802	262,000	44.0%	47.7%	48.9%	53.7%	74.4%	15.0%
RFC-MISO	51,226	49,601	70,714	71,138	72,732	73,544	76,953	42.6%	43.4%	46.6%	48.3%	55.1%	15.4%
RFC-PJM	103,790	100,925	142,022	147,228	147,319	153,732	181,458	40.7%	45.9%	46.0%	52.3%	79.8%	16.2%
SERC	193,586	187,364	243,169	256,459	272,591	272,591	276,709	29.8%	36.9%	45.5%	45.5%	47.7%	15.0%
Central	44,116	42,324	51,023	53,398	56,556	56,556	56,768	20.6%	26.2%	33.6%	33.6%	34.1%	15.0%
Delta	25,159	24,568	37,783	38,997	40,057	40,057	40,057	53.8%	58.7%	63.0%	63.0%	63.0%	15.0%
Gateway	16,395	16,320	23,607	24,669	25,469	25,469	25,469	44.7%	51.2%	56.1%	56.1%	56.1%	12.7%
Southeastern	45,770	43,839	55,117	58,906	67,909	67,909	71,065	25.7%	34.4%	54.9%	54.9%	62.1%	15.0%
VACAR	62,146	60,313	75,639	80,489	82,600	82,600	83,350	25.4%	33.5%	37.0%	37.0%	38.2%	15.0%
SPP	34,961	34,022	48,991	52,933	59,502	59,649	62,916	44.0%	55.6%	74.9%	75.3%	84.9%	13.6%
WECC	118,280	114,867	167,517	193,056	193,056	194,392	196,632	45.8%	68.1%	68.1%	69.2%	71.2%	16.7%
AZ-NM-SNV	20,661	19,957	38,212	39,719	39,719	40,222	41,553	91.5%	99.0%	99.0%	101.5%	108.2%	15.5%
CA-MX US	43,475	41,162	60,082	80,295	80,295	80,295	80,312	46.0%	95.1%	95.1%	95.1%	95.1%	15.9%
NWPP	44,414	44,076	55,673	57,240	57,240	57,353	57,793	26.3%	29.9%	29.9%	30.1%	31.1%	18.4%
RMPA	10,789	10,529	13,616	15,257	15,257	15,959	16,323	29.3%	44.9%	44.9%	51.6%	55.0%	15.4%
Total-U.S.	684,347	661,874	925,025	993,649	1,019,408	1,032,086	1,123,543	39.8%	50.1%	54.0%	55.9%	69.8%	15.0%
Canada													
MRO	8,405	8,144	8,798	9,815	9,815	10,135	10,883	8.0%	20.5%	20.5%	24.5%	33.6%	10.0%
NPCC	65,553	63,368	72,356	81,527	81,506	81,506	82,305	14.2%	28.7%	28.6%	28.6%	29.9%	15.0%
Maritimes	5,556	5,121	6,266	7,176	7,176	7,176	7,192	22.4%	40.1%	40.1%	40.1%	40.4%	20.0%
Ontario	21,575	21,575	25,851	32,899	32,899	33,682	33,682	19.8%	52.5%	52.5%	56.1%	56.1%	19.1%
Quebec	38,422	36,672	40,239	41,452	41,431	41,431	41,431	9.7%	13.0%	13.0%	13.0%	13.0%	11.7%
WECC	23,431	23,431	24,352	25,335	25,335	26,520	28,722	3.9%	8.1%	8.1%	13.2%	22.6%	12.5%
Total-Canada	97,389	94,943	105,506	116,677	116,656	118,161	121,910	11.1%	22.9%	22.9%	24.5%	28.4%	10.0%
Mexico													
WECC CA-MX Mex	1,636	1,636	1,823	1,854	1,854	2,167	2,167	11.4%	13.3%	13.3%	32.5%	32.5%	10.1%
Total-NERC	783,371	758,453	1,032,354	1,112,179	1,137,918	1,152,414	1,247,620	36.1%	46.6%	50.0%	51.9%	64.5%	15.0%

Table Margins 2e: Estimated 2018 Summer Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	76,134	75,019	72,208	79,525	79,525	84,969	106,745	-3.7%	6.0%	6.0%	13.3%	42.3%	12.5%
FRCC	53,689	49,885	48,005	63,336	63,336	63,336	64,690	-3.8%	27.0%	27.0%	27.0%	29.7%	15.0%
MRO	50,587	47,534	47,484	49,469	49,598	54,317	64,746	-0.1%	4.1%	4.3%	14.3%	36.2%	15.0%
NPCC	66,410	66,191	72,845	78,579	78,798	79,155	95,271	10.1%	18.7%	19.0%	19.6%	43.9%	15.0%
New England	30,960	30,960	33,150	34,499	34,717	37,209	47,441	7.1%	11.4%	12.1%	20.2%	53.2%	15.0%
New York	35,450	35,231	39,696	44,081	44,081	44,777	47,830	12.7%	25.1%	25.1%	27.1%	35.8%	16.5%
RFC	201,300	193,100	214,000	219,800	221,500	230,054	267,900	10.8%	13.8%	14.7%	19.1%	38.7%	15.0%
RFC-MISO	66,650	64,950	70,714	71,138	72,732	74,016	79,461	8.9%	9.5%	12.0%	14.0%	22.3%	15.4%
RFC-PJM	134,524	128,024	142,022	147,368	147,459	154,772	187,144	10.9%	15.1%	15.2%	20.9%	46.2%	16.2%
SERC	237,386	228,862	241,777	262,372	276,673	276,748	290,774	5.6%	14.6%	20.9%	20.9%	27.1%	15.0%
Central	48,597	45,288	49,104	54,410	55,927	55,927	57,061	8.4%	20.1%	23.5%	23.5%	26.0%	15.0%
Delta	32,204	31,438	35,485	36,161	37,167	37,167	40,505	12.9%	15.0%	18.2%	18.2%	28.8%	15.0%
Gateway	20,932	20,817	23,668	24,916	25,727	25,727	25,727	13.7%	19.7%	23.6%	23.6%	23.6%	12.7%
Southeastern	60,602	58,505	61,153	67,860	77,047	77,047	82,853	4.5%	16.0%	31.7%	31.7%	41.6%	15.0%
VACAR	75,051	72,814	72,367	79,025	80,805	80,880	84,628	-0.6%	8.5%	11.0%	11.1%	16.2%	15.0%
SPP	49,696	48,500	49,094	53,319	59,846	60,141	65,880	1.2%	9.9%	23.4%	24.0%	35.8%	13.6%
WECC	163,547	156,938	172,385	207,945	207,945	210,904	215,058	9.8%	32.5%	32.5%	34.4%	37.0%	17.9%
AZ-NM-SNV	37,300	36,382	36,409	43,381	43,381	44,819	47,037	0.1%	19.2%	19.2%	23.2%	29.3%	17.8%
CA-MX US	68,683	63,916	71,597	89,054	89,054	89,054	89,506	12.0%	39.3%	39.3%	39.3%	40.0%	22.3%
NWPP	46,633	45,733	50,984	61,197	61,197	61,678	62,424	11.5%	33.8%	33.8%	34.9%	36.5%	16.3%
RMPA	13,252	12,874	13,853	15,102	15,102	16,146	16,883	7.6%	17.3%	17.3%	25.4%	31.1%	17.1%
Total-U.S.	898,749	866,028	917,798	1,014,345	1,037,220	1,059,624	1,171,063	6.0%	17.1%	19.8%	22.4%	35.2%	15.0%
Canada													
MRO	7,380	7,120	8,695	9,969	9,969	10,290	11,037	22.1%	40.0%	40.0%	44.5%	55.0%	10.0%
NPCC	49,439	49,006	54,124	64,662	64,167	64,167	69,645	10.4%	31.9%	30.9%	30.9%	42.1%	15.0%
Maritimes	3,620	3,187	6,135	6,948	6,948	6,948	6,972	92.5%	118.0%	118.0%	118.0%	118.8%	20.3%
Ontario	22,497	22,497	16,363	23,565	23,091	28,545	28,545	-27.3%	4.7%	2.6%	26.9%	26.9%	20.3%
Quebec	23,322	23,322	31,626	34,149	34,128	34,128	34,128	35.6%	46.4%	46.3%	46.3%	46.3%	11.7%
WECC	22,006	22,006	21,756	22,730	22,730	26,684	28,002	-1.1%	3.3%	3.3%	21.3%	27.2%	12.5%
Total-Canada	78,825	78,132	84,575	97,361	96,866	101,140	108,684	8.2%	24.6%	24.0%	29.4%	39.1%	10.0%
Mexico													
WECC CA-MX Mex	2,650	2,650	2,287	2,788	2,788	3,651	3,651	-13.7%	5.2%	5.2%	37.8%	37.8%	15.6%
Total-NERC	980,224	946,810	1,004,659	1,114,494	1,136,874	1,164,415	1,283,399	6.1%	17.7%	20.1%	23.0%	35.5%	15.0%

Table Margins 2f: Estimated 2018/19 Winter Demand, Resources, and Reserve Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Reserve Margin (%)	Prospective Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	Potential Reserve Margin (%)	NERC Reference Reserve Margin Level (%)
United States													
ERCOT	52,405	51,290	73,916	81,233	81,233	81,233	108,453	44.1%	58.4%	58.4%	58.4%	111.4%	12.5%
FRCC	53,065	48,984	51,345	68,087	68,087	68,087	69,441	4.8%	39.0%	39.0%	39.0%	41.8%	15.0%
MRO	41,394	39,320	47,399	49,353	50,157	54,877	65,305	20.5%	25.5%	27.6%	39.6%	66.1%	15.0%
NPCC	48,898	48,898	74,057	76,718	77,274	77,274	93,600	51.5%	56.9%	58.0%	58.0%	91.4%	15.0%
New England	22,860	22,860	33,926	35,350	35,906	38,398	48,563	48.4%	54.6%	57.1%	68.0%	112.4%	15.0%
New York	26,038	26,038	40,131	41,368	41,368	41,735	45,037	54.1%	58.9%	58.9%	60.3%	73.0%	16.5%
RFC	161,600	156,700	216,300	222,100	223,800	232,354	270,200	38.0%	41.7%	42.8%	48.3%	72.4%	15.0%
RFC-MISO	52,985	51,360	70,714	71,138	72,732	74,016	79,461	37.7%	38.5%	41.6%	44.1%	54.7%	15.4%
RFC-PJM	108,525	105,660	142,022	147,368	147,459	154,772	187,144	34.4%	39.5%	39.6%	46.5%	77.1%	16.2%
SERC	206,639	200,181	244,553	260,941	278,873	278,873	291,793	22.2%	30.4%	39.3%	39.3%	45.8%	15.0%
Central	44,894	43,096	51,049	53,424	56,582	56,582	57,433	18.5%	24.0%	31.3%	31.3%	33.3%	15.0%
Delta	27,201	26,618	36,146	37,360	38,420	38,420	40,920	35.8%	40.4%	44.3%	44.3%	53.7%	15.0%
Gateway	17,212	17,137	23,604	24,702	25,502	25,502	25,502	37.7%	44.1%	48.8%	48.8%	48.8%	12.7%
Southeastern	50,298	48,182	59,194	66,009	75,242	75,242	81,048	22.9%	37.0%	56.2%	56.2%	68.2%	15.0%
VACAR	67,034	65,148	74,560	79,446	83,127	83,127	86,890	14.4%	21.9%	27.6%	27.6%	33.4%	15.0%
SPP	37,047	36,028	48,489	52,781	59,354	59,650	65,738	34.6%	46.5%	64.7%	65.6%	82.5%	13.6%
WECC	127,515	124,005	167,813	193,051	193,051	196,122	200,242	35.3%	55.7%	55.7%	58.2%	61.5%	16.7%
AZ-NM-SNV	23,221	22,476	37,055	39,481	39,481	40,958	43,169	64.9%	75.7%	75.7%	82.2%	92.1%	15.5%
CA-MX US	45,926	43,584	59,850	80,530	80,530	80,530	80,937	37.3%	84.8%	84.8%	84.8%	85.7%	15.9%
NWPP	47,639	47,292	56,749	57,687	57,687	58,200	58,961	20.0%	22.0%	22.0%	23.1%	24.7%	18.4%
RMPA	12,038	11,762	13,965	14,704	14,704	15,804	16,523	18.7%	25.0%	25.0%	34.4%	40.5%	15.4%
Total-U.S.	728,563	705,406	923,872	1,004,265	1,031,830	1,048,469	1,164,772	31.0%	42.4%	46.3%	48.6%	65.1%	15.0%
Canada													
MRO	8,789	8,528	9,011	10,399	10,399	10,719	11,467	5.7%	21.9%	21.9%	25.7%	34.5%	10.0%
NPCC	67,266	65,489	62,075	72,815	72,794	72,794	78,242	-5.2%	11.2%	11.2%	11.2%	19.5%	15.0%
Maritimes	5,765	5,338	6,266	7,176	7,176	7,176	7,240	17.4%	34.4%	34.4%	34.4%	35.6%	20.3%
Ontario	20,845	20,845	15,623	22,930	22,930	28,314	28,314	-25.1%	10.0%	10.0%	35.8%	35.8%	20.3%
Quebec	40,656	39,306	40,186	42,709	42,688	42,688	42,688	2.2%	8.7%	8.6%	8.6%	8.6%	11.7%
WECC	25,514	25,514	23,885	25,335	25,335	29,289	30,607	-6.4%	-0.7%	-0.7%	14.8%	20.0%	12.5%
Total-Canada	101,569	99,531	94,971	108,548	108,527	112,802	120,316	-4.6%	9.1%	9.0%	13.3%	20.9%	10.0%
Mexico													
WECC CA-MX Mex	1,842	1,842	2,055	2,054	2,054	2,917	2,917	11.6%	11.5%	11.5%	58.4%	58.4%	10.1%
Total-NERC	831,974	806,779	1,020,898	1,114,867	1,142,411	1,164,188	1,288,004	26.5%	38.2%	41.6%	44.3%	59.6%	15.0%

Table Margins 3a: Estimated 2009 Summer Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	63,491	62,376	72,204	72,204	72,204	72,204	72,204	13.6%	13.6%	13.6%	13.6%	13.6%	11.1%
FRCC	45,734	42,531	49,239	51,870	51,870	51,870	53,210	13.6%	18.0%	18.0%	18.0%	18.0%	13.0%
MRO	44,206	41,306	49,648	50,308	50,316	51,098	52,925	16.8%	17.9%	17.9%	19.5%	19.2%	13.0%
NPCC	61,327	61,108	73,678	76,671	76,889	77,579	77,647	17.1%	20.3%	20.5%	21.4%	21.2%	13.0%
New England	27,875	27,875	33,475	33,703	33,921	33,921	33,989	16.7%	17.3%	17.8%	17.8%	17.8%	13.0%
New York	33,452	33,233	40,203	42,968	42,968	43,658	43,658	17.3%	22.7%	22.7%	24.3%	23.9%	13.0%
RFC	178,100	169,900	215,700	215,800	217,600	217,904	219,200	21.2%	21.3%	21.9%	22.1%	22.0%	13.0%
RFC-MISO	62,419	60,719	70,714	70,714	72,308	72,308	72,308	14.1%	14.1%	16.0%	16.0%	16.0%	13.0%
RFC-PJM	116,153	109,653	144,837	144,939	145,113	145,422	146,740	24.3%	24.3%	24.4%	24.6%	24.6%	13.0%
SERC	202,738	196,871	242,787	244,008	256,129	256,129	256,433	18.9%	19.3%	23.1%	23.1%	23.1%	13.0%
Central	42,733	40,874	50,660	50,828	51,196	51,196	51,500	19.3%	19.6%	20.2%	20.2%	20.2%	13.0%
Delta	27,865	27,178	38,433	38,466	38,602	38,602	38,602	29.3%	29.3%	29.6%	29.6%	29.6%	13.0%
Gateway	19,065	18,947	20,306	20,306	21,117	21,117	21,117	6.7%	6.7%	10.3%	10.3%	10.3%	13.0%
Southeastern	49,504	47,789	58,745	58,745	67,788	67,788	67,788	18.7%	18.7%	29.5%	29.5%	29.5%	13.0%
VACAR	63,571	62,083	74,643	75,663	77,426	77,426	77,426	16.8%	17.9%	19.8%	19.8%	19.8%	13.0%
SPP	44,463	43,696	49,706	50,127	56,619	56,648	57,206	12.1%	12.8%	22.8%	22.9%	22.9%	13.0%
WECC	140,692	136,441	172,375	174,978	174,978	174,980	174,985	20.8%	22.0%	22.0%	22.0%	22.0%	12.1%
AZ-NM-SNV	30,452	29,843	35,156	35,076	35,076	35,076	35,077	15.1%	14.9%	14.9%	14.9%	14.9%	11.7%
CA-MX US	61,237	58,421	71,447	71,334	71,334	71,334	71,334	18.2%	18.1%	18.1%	18.1%	18.1%	13.3%
NWPP	39,754	39,155	56,001	57,340	57,340	57,342	57,346	30.1%	31.7%	31.7%	31.7%	31.7%	11.9%
RMPA	11,224	10,939	12,815	13,517	13,517	13,517	13,517	14.6%	19.1%	19.1%	19.1%	19.1%	10.5%
Total-U.S.	780,751	754,229	925,336	935,965	956,605	958,413	963,810	18.5%	19.4%	21.2%	21.3%	21.3%	13.0%
Canada													
MRO	6,369	6,082	7,372	7,372	7,372	7,385	7,414	17.5%	17.5%	17.5%	17.7%	17.6%	9.0%
NPCC	48,471	48,026	65,078	66,855	67,456	67,456	67,456	26.2%	28.2%	28.8%	28.8%	28.8%	13.0%
Maritimes	3,499	3,054	5,987	5,987	5,987	5,987	5,987	49.0%	49.0%	49.0%	49.0%	49.0%	13.0%
Ontario	24,351	24,351	28,011	29,788	30,410	30,410	30,410	13.1%	18.3%	19.9%	19.9%	19.9%	14.5%
Quebec	20,621	20,621	31,080	31,080	31,059	31,059	31,059	33.7%	33.7%	33.6%	33.6%	33.6%	9.1%
WECC	18,071	18,071	22,099	22,277	22,277	22,277	22,370	18.2%	18.9%	18.9%	18.9%	18.9%	10.2%
Total-Canada	72,911	72,179	94,549	96,504	97,105	97,118	97,240	23.7%	25.2%	25.7%	25.7%	25.7%	13.0%
Mexico													
WECC CA-MX Mex	2,115	2,115	2,446	2,446	2,446	2,446	2,446	13.5%	13.5%	13.5%	13.5%	13.5%	12.5%
Total-NERC	855,777	828,523	1,022,331	1,034,915	1,056,156	1,057,976	1,063,496	19.0%	19.9%	21.6%	21.7%	21.7%	13.0%

Table 3b: Estimated 2009/10 Winter Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	43,463	42,348	73,916	74,797	74,797	74,797	74,797	42.7%	43.4%	43.4%	43.4%	43.4%	11.1%
FRCC	44,446	40,846	52,751	57,216	57,216	57,216	58,556	22.6%	28.6%	28.6%	28.6%	28.6%	13.0%
MRO	36,904	34,985	48,104	48,417	49,165	49,948	51,774	27.3%	27.7%	28.8%	30.4%	30.0%	13.0%
NPCC	47,098	47,098	76,849	77,577	78,092	78,092	78,561	38.7%	39.3%	39.7%	39.7%	39.7%	13.0%
New England	22,100	22,100	36,210	36,545	37,060	37,060	37,529	39.0%	39.5%	40.4%	40.4%	40.4%	13.0%
New York	24,998	24,998	40,639	41,032	41,032	41,032	41,032	38.5%	39.1%	39.1%	39.1%	39.1%	13.0%
RFC	145,800	140,900	218,000	218,100	219,800	220,104	221,400	35.4%	35.4%	35.9%	36.0%	36.0%	13.0%
RFC-MISO	49,051	47,426	70,714	70,714	72,308	72,308	72,308	32.9%	32.9%	34.4%	34.4%	34.4%	13.0%
RFC-PJM	96,644	93,395	144,837	144,939	145,113	145,422	146,740	35.5%	35.6%	35.6%	35.9%	35.8%	13.0%
SERC	181,045	175,541	248,673	251,192	263,272	263,272	263,701	29.4%	30.1%	33.3%	33.3%	33.3%	13.0%
Central	42,240	40,636	52,618	52,785	53,204	53,204	53,207	22.8%	23.0%	23.6%	23.6%	23.6%	13.0%
Delta	23,023	22,501	40,674	40,707	40,862	40,862	40,862	44.7%	44.7%	44.9%	44.9%	44.9%	13.0%
Gateway	15,696	15,608	21,219	22,084	22,554	22,554	22,554	26.4%	29.3%	30.8%	30.8%	30.8%	13.0%
Southeastern	41,869	40,147	57,450	57,800	66,884	66,884	67,310	30.1%	30.5%	40.0%	40.0%	40.0%	13.0%
VACAR	58,217	56,649	76,712	77,816	79,768	79,768	79,768	26.2%	27.2%	29.0%	29.0%	29.0%	13.0%
SPP	32,636	31,988	49,112	49,535	55,949	55,978	56,536	34.9%	35.4%	42.8%	42.9%	42.9%	13.0%
WECC	111,324	108,535	168,290	173,502	173,502	173,504	173,509	35.5%	37.4%	37.4%	37.4%	37.4%	12.1%
AZ-NM-SNV	18,868	18,176	38,089	38,775	38,775	38,775	38,777	52.3%	53.1%	53.1%	53.1%	53.1%	11.7%
CA-MX US	41,922	40,029	60,278	63,393	63,393	63,393	63,393	33.6%	36.9%	36.9%	36.9%	36.9%	13.3%
NWPP	41,681	41,391	55,850	56,705	56,705	56,710	56,720	25.9%	27.0%	27.0%	27.0%	27.0%	11.9%
RMPA	9,658	9,479	13,712	14,811	14,811	14,811	14,811	30.9%	36.0%	36.0%	36.0%	36.0%	10.5%
Total-U.S.	642,716	622,241	935,694	950,335	971,792	972,910	978,834	33.5%	34.5%	36.0%	36.1%	36.0%	13.0%
Canada													
MRO	7,620	7,332	8,715	8,914	8,881	8,894	8,923	15.9%	17.7%	17.4%	17.6%	17.6%	9.0%
NPCC	64,690	62,499	72,293	75,173	75,789	75,789	75,789	13.5%	16.9%	17.5%	17.5%	17.5%	13.0%
Maritimes	5,554	5,113	6,118	6,887	6,887	6,887	6,887	16.4%	25.8%	25.8%	25.8%	25.8%	13.0%
Ontario	22,886	22,886	26,028	28,104	28,741	28,741	28,741	12.1%	18.6%	20.4%	20.4%	20.4%	14.5%
Quebec	36,250	34,500	40,147	40,182	40,161	40,161	40,161	14.1%	14.1%	14.1%	14.1%	14.1%	9.1%
WECC	21,548	21,548	24,389	24,513	24,513	24,513	24,888	11.6%	12.1%	12.1%	12.1%	12.1%	10.2%
Total-Canada	93,858	91,379	105,397	108,600	109,183	109,195	109,600	13.3%	15.9%	16.3%	16.3%	16.3%	13.0%
Mexico													
WECC CA-MX Mex	1,480	1,480	1,930	1,930	1,930	1,930	1,930	23.3%	23.3%	23.3%	23.3%	23.3%	12.5%
Total-NERC	738,054	715,100	1,043,022	1,060,866	1,082,905	1,084,036	1,090,364	31.4%	32.6%	34.0%	34.1%	34.0%	13.0%

Table 3c: Estimated 2013 Summer Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	69,399	68,284	72,204	79,521	79,521	84,617	105,000	5.4%	14.1%	14.1%	20.5%	19.3%	11.1%
FRCC	48,304	44,697	49,330	57,464	57,464	57,464	58,811	9.4%	22.2%	22.2%	22.2%	22.2%	13.0%
MRO	47,500	44,482	49,159	50,218	50,309	54,299	63,612	9.5%	11.4%	11.6%	19.5%	18.1%	13.0%
NPCC	63,445	63,226	73,223	78,207	78,426	78,683	92,524	13.7%	19.2%	19.4%	19.7%	19.6%	13.0%
New England	29,365	29,365	33,478	34,827	35,045	37,122	45,694	12.3%	15.7%	16.2%	22.1%	20.9%	13.0%
New York	34,080	33,861	39,746	43,381	43,381	43,957	46,830	14.8%	21.9%	21.9%	23.3%	23.0%	13.0%
RFC	192,100	183,900	214,000	219,600	221,300	228,502	259,700	14.1%	16.3%	16.9%	20.2%	19.5%	13.0%
RFC-MISO	64,924	63,224	70,714	71,138	72,732	73,544	76,953	10.6%	11.1%	13.1%	14.2%	14.0%	13.0%
RFC-PJM	127,079	120,579	142,022	147,228	147,319	153,732	181,458	15.1%	18.1%	18.2%	22.5%	21.6%	13.0%
SERC	219,712	211,900	240,012	253,404	267,483	267,583	271,933	11.7%	16.4%	20.8%	20.8%	20.8%	13.0%
Central	45,345	42,437	49,607	52,473	53,990	53,990	54,516	14.5%	19.1%	21.4%	21.4%	21.4%	13.0%
Delta	30,187	29,406	36,823	37,499	38,505	38,505	39,043	20.1%	21.6%	23.6%	23.6%	23.6%	13.0%
Gateway	20,144	20,032	23,707	24,834	25,645	25,645	25,645	15.5%	19.3%	21.9%	21.9%	21.9%	13.0%
Southeastern	55,018	53,099	56,306	59,987	68,949	68,949	72,105	5.7%	11.5%	23.0%	23.0%	23.0%	13.0%
VACAR	69,018	66,926	73,569	78,611	80,394	80,494	80,624	9.0%	14.9%	16.8%	16.9%	16.9%	13.0%
SPP	47,255	46,153	49,602	53,477	60,001	60,149	63,067	7.0%	13.7%	23.1%	23.3%	23.3%	13.0%
WECC	150,163	143,988	172,192	204,058	204,058	205,307	207,579	16.4%	29.4%	29.4%	30.0%	29.9%	12.1%
AZ-NM-SNV	32,897	32,060	36,512	39,157	39,157	39,663	41,072	12.2%	18.1%	18.1%	19.4%	19.2%	11.7%
CA-MX US	64,493	60,073	71,622	89,293	89,293	89,293	89,355	16.1%	32.7%	32.7%	32.7%	32.7%	13.3%
NWPP	42,942	42,117	50,768	61,577	61,577	61,664	62,074	17.0%	31.6%	31.6%	31.7%	31.7%	11.9%
RMPA	12,015	11,616	13,853	14,483	14,483	15,131	15,514	16.1%	19.8%	19.8%	24.3%	23.2%	10.5%
Total-U.S.	837,878	806,630	919,722	995,948	1,018,561	1,036,603	1,122,225	12.3%	19.0%	20.8%	22.6%	22.2%	13.0%
Canada													
MRO	7,086	6,826	7,617	8,414	8,414	8,735	9,482	10.4%	18.9%	18.9%	22.7%	21.8%	9.0%
NPCC	48,594	48,154	64,281	73,200	72,974	72,974	73,757	25.1%	34.2%	34.0%	34.0%	34.0%	13.0%
Maritimes	3,502	3,062	6,135	6,948	6,948	6,948	6,948	50.1%	55.9%	55.9%	55.9%	55.9%	13.0%
Ontario	23,092	23,092	26,467	33,410	33,205	33,988	33,988	12.8%	30.9%	30.5%	32.8%	32.1%	14.5%
Quebec	22,000	22,000	31,679	32,842	32,821	32,821	32,821	30.6%	33.0%	33.0%	33.0%	33.0%	9.1%
WECC	19,927	19,927	22,079	23,053	23,053	24,238	26,440	9.7%	13.6%	13.6%	18.7%	17.8%	10.2%
Total-Canada	75,608	74,908	93,977	104,668	104,441	105,947	109,680	20.3%	28.4%	28.3%	29.7%	29.3%	13.0%
Mexico													
WECC CA-MX Mex	2,345	2,345	2,287	2,713	2,713	3,026	3,026	-2.5%	13.6%	13.6%	25.1%	22.5%	12.5%
Total-NERC	915,830	883,882	1,015,986	1,103,329	1,125,715	1,145,577	1,234,931	13.0%	19.9%	21.5%	23.2%	22.8%	13.0%

Table 3d: Estimated 2013/14 Winter Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	47,984	46,869	73,916	81,233	81,233	81,233	106,829	36.6%	42.3%	42.3%	42.3%	42.3%	11.1%
FRCC	47,709	43,813	52,827	62,001	62,001	62,001	63,349	17.1%	29.3%	29.3%	29.3%	29.3%	13.0%
MRO	39,107	37,119	48,197	49,299	50,102	54,092	63,405	23.0%	24.7%	25.9%	33.9%	31.4%	13.0%
NPCC	47,620	47,620	74,107	76,768	77,324	77,324	91,703	35.7%	38.0%	38.4%	38.4%	38.4%	13.0%
New England	22,335	22,335	33,926	35,350	35,906	38,009	46,616	34.2%	36.8%	37.8%	43.7%	41.2%	13.0%
New York	25,285	25,285	40,181	41,418	41,418	41,785	45,087	37.1%	39.0%	39.0%	39.8%	39.5%	13.0%
RFC	155,100	150,200	216,300	221,900	223,600	230,802	262,000	30.6%	32.3%	32.8%	36.0%	34.9%	13.0%
RFC-MISO	51,226	49,601	70,714	71,138	72,732	73,544	76,953	29.9%	30.3%	31.8%	32.9%	32.6%	13.0%
RFC-PJM	103,790	100,925	142,022	147,228	147,319	153,732	181,458	28.9%	31.4%	31.5%	35.8%	34.4%	13.0%
SERC	193,586	187,364	243,169	256,459	272,591	272,591	276,709	22.9%	26.9%	31.3%	31.3%	31.3%	13.0%
Central	44,116	42,324	51,023	53,398	56,556	56,556	56,768	17.0%	20.7%	25.2%	25.2%	25.2%	13.0%
Delta	25,159	24,568	37,783	38,997	40,057	40,057	40,057	35.0%	37.0%	38.7%	38.7%	38.7%	13.0%
Gateway	16,395	16,320	23,607	24,669	25,469	25,469	25,469	30.9%	33.8%	35.9%	35.9%	35.9%	13.0%
Southeastern	45,770	43,839	55,117	58,906	67,909	67,909	71,065	20.5%	25.6%	35.4%	35.4%	35.4%	13.0%
VACAR	62,146	60,313	75,639	80,489	82,600	82,600	83,350	20.3%	25.1%	27.0%	27.0%	27.0%	13.0%
SPP	34,961	34,022	48,991	52,933	59,502	59,649	62,916	30.6%	35.7%	42.8%	43.1%	43.0%	13.0%
WECC	118,280	114,867	167,517	193,056	193,056	194,392	196,632	31.4%	40.5%	40.5%	41.2%	40.9%	12.1%
AZ-NM-SNV	20,661	19,957	38,212	39,719	39,719	40,222	41,553	47.8%	49.8%	49.8%	51.0%	50.4%	11.7%
CA-MX US	43,475	41,162	60,082	80,295	80,295	80,295	80,312	31.5%	48.7%	48.7%	48.7%	48.7%	13.3%
NWPP	44,414	44,076	55,673	57,240	57,240	57,353	57,793	20.8%	23.0%	23.0%	23.2%	23.2%	11.9%
RMPA	10,789	10,529	13,616	15,257	15,257	15,959	16,323	22.7%	31.0%	31.0%	35.6%	34.0%	10.5%
Total-U.S.	684,347	661,874	925,025	993,649	1,019,408	1,032,086	1,123,543	28.4%	33.4%	35.1%	36.3%	35.9%	13.0%
Canada													
MRO	8,405	8,144	8,798	9,815	9,815	10,135	10,883	7.4%	17.0%	17.0%	20.3%	19.6%	9.0%
NPCC	65,553	63,368	72,356	81,527	81,506	81,506	82,305	12.4%	22.3%	22.3%	22.3%	22.3%	13.0%
Maritimes	5,556	5,121	6,266	7,176	7,176	7,176	7,192	18.3%	28.6%	28.6%	28.6%	28.6%	13.0%
Ontario	21,575	21,575	25,851	32,899	32,899	33,682	33,682	16.5%	34.4%	34.4%	36.8%	35.9%	14.5%
Quebec	38,422	36,672	40,239	41,452	41,431	41,431	41,431	8.9%	11.5%	11.5%	11.5%	11.5%	9.1%
WECC	23,431	23,431	24,352	25,335	25,335	26,520	28,722	3.8%	7.5%	7.5%	12.2%	11.6%	10.2%
Total-Canada	97,389	94,943	105,506	116,677	116,656	118,161	121,910	10.0%	18.6%	18.6%	19.9%	19.7%	13.0%
Mexico													
WECC CA-MX Mex	1,636	1,636	1,823	1,854	1,854	2,167	2,167	10.3%	11.8%	11.8%	28.6%	24.5%	12.5%
Total-NERC	783,371	758,453	1,032,354	1,112,179	1,137,918	1,152,414	1,247,620	26.5%	31.8%	33.3%	34.6%	34.2%	13.0%

Table 3e: Estimated 2018 Summer Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	76,134	75,019	72,208	79,525	79,525	84,969	106,745	-3.9%	5.7%	5.7%	12.5%	11.7%	11.1%
FRCC	53,689	49,885	48,005	63,336	63,336	63,336	64,690	-3.9%	21.2%	21.2%	21.2%	21.2%	13.0%
MRO	50,587	47,534	47,484	49,469	49,598	54,317	64,746	-0.1%	3.9%	4.2%	13.7%	12.5%	13.0%
NPCC	66,410	66,191	72,845	78,579	78,798	79,155	95,271	9.1%	15.8%	16.0%	16.5%	16.4%	13.0%
New England	30,960	30,960	33,150	34,499	34,717	37,209	47,441	6.6%	10.3%	10.8%	18.0%	16.8%	13.0%
New York	35,450	35,231	39,696	44,081	44,081	44,777	47,830	11.2%	20.1%	20.1%	21.7%	21.3%	13.0%
RFC	201,300	193,100	214,000	219,800	221,500	230,054	267,900	9.8%	12.1%	12.8%	16.7%	16.1%	13.0%
RFC-MISO	66,650	64,950	70,714	71,138	72,732	74,016	79,461	8.2%	8.7%	10.7%	12.5%	12.2%	13.0%
RFC-PJM	134,524	128,024	142,022	147,368	147,459	154,772	187,144	9.9%	13.1%	13.2%	18.1%	17.3%	13.0%
SERC	237,386	228,862	241,777	262,372	276,673	276,748	290,774	5.3%	12.8%	17.3%	17.3%	17.3%	13.0%
Central	48,597	45,288	49,104	54,410	55,927	55,927	57,061	7.8%	16.8%	19.0%	19.0%	19.0%	13.0%
Delta	32,204	31,438	35,485	36,161	37,167	37,167	40,505	11.4%	13.1%	15.4%	15.4%	15.4%	13.0%
Gateway	20,932	20,817	23,668	24,916	25,727	25,727	25,727	12.0%	16.5%	19.1%	19.1%	19.1%	13.0%
Southeastern	60,602	58,505	61,153	67,860	77,047	77,047	82,853	4.3%	13.8%	24.1%	24.1%	24.1%	13.0%
VACAR	75,051	72,814	72,367	79,025	80,805	80,880	84,628	-0.6%	7.9%	9.9%	10.0%	10.0%	13.0%
SPP	49,696	48,500	49,094	53,319	59,846	60,141	65,880	1.2%	9.0%	19.0%	19.5%	19.4%	13.0%
WECC	163,547	156,938	172,385	207,945	207,945	210,904	215,058	9.0%	24.5%	24.5%	26.0%	25.6%	12.1%
AZ-NM-SNV	37,300	36,382	36,409	43,381	43,381	44,819	47,037	0.1%	16.1%	16.1%	19.4%	18.8%	11.7%
CA-MX US	68,683	63,916	71,597	89,054	89,054	89,054	89,506	10.7%	28.2%	28.2%	28.2%	28.2%	13.3%
NWPP	46,633	45,733	50,984	61,197	61,197	61,678	62,424	10.3%	25.3%	25.3%	26.1%	25.9%	11.9%
RMPA	13,252	12,874	13,853	15,102	15,102	16,146	16,883	7.1%	14.8%	14.8%	21.7%	20.3%	10.5%
Total-U.S.	898,749	866,028	917,798	1,014,345	1,037,220	1,059,624	1,171,063	5.6%	14.6%	16.5%	18.7%	18.3%	13.0%
Canada													
MRO	7,380	7,120	8,695	9,969	9,969	10,290	11,037	18.1%	28.6%	28.6%	31.8%	30.8%	9.0%
NPCC	49,439	49,006	54,124	64,662	64,167	64,167	69,645	9.5%	24.2%	23.6%	23.6%	23.6%	13.0%
Maritimes	3,620	3,187	6,135	6,948	6,948	6,948	6,972	48.1%	54.1%	54.1%	54.1%	54.1%	13.0%
Ontario	22,497	22,497	16,363	23,565	23,091	28,545	28,545	-37.5%	4.5%	2.6%	26.2%	21.2%	14.5%
Quebec	23,322	23,322	31,626	34,149	34,128	34,128	34,128	26.3%	31.7%	31.7%	31.7%	31.7%	9.1%
WECC	22,006	22,006	21,756	22,730	22,730	26,684	28,002	-1.1%	3.2%	3.2%	20.6%	17.5%	10.2%
Total-Canada	78,825	78,132	84,575	97,361	96,866	101,140	108,684	7.6%	19.8%	19.3%	23.8%	22.7%	13.0%
Mexico													
WECC CA-MX Mex	2,650	2,650	2,287	2,788	2,788	3,651	3,651	-15.9%	4.9%	4.9%	35.9%	27.4%	12.5%
Total-NERC	980,224	946,810	1,004,659	1,114,494	1,136,874	1,164,415	1,283,399	5.8%	15.0%	16.7%	19.1%	18.7%	13.0%

Table 3f: Estimated 2018/19 Winter Demand, Resources, and Capacity Margins

	Total Internal Demand (MW)	Net Internal Demand (MW)	Existing Certain & Net Firm Trans-actions (MW)	Deliverable Capacity Resources (MW)	Prospective Capacity Resources (MW)	Adjusted Potential Capacity Resources (MW)	Potential Capacity Resources (MW)	Existing Certain & Net Firm Trans-actions (%)	Deliverable Capacity Margin (%)	Prospective Capacity Margin (%)	Adjusted Potential Capacity Margin (%)	Potential Capacity Margin (%)	NERC Reference Capacity Margin Level (%)
United States													
ERCOT	52,405	51,290	73,916	81,233	81,233	81,233	108,453	30.6%	36.9%	36.9%	36.9%	36.9%	11.1%
FRCC	53,065	48,984	51,345	68,087	68,087	68,087	69,441	4.6%	28.1%	28.1%	28.1%	28.1%	13.0%
MRO	41,394	39,320	47,399	49,353	50,157	54,877	65,305	17.0%	20.3%	21.6%	31.0%	28.3%	13.0%
NPCC	48,898	48,898	74,057	76,718	77,274	77,274	93,600	34.0%	36.3%	36.7%	36.7%	36.7%	13.0%
New England	22,860	22,860	33,926	35,350	35,906	38,398	48,563	32.6%	35.3%	36.3%	43.3%	40.5%	13.0%
New York	26,038	26,038	40,131	41,368	41,368	41,735	45,037	35.1%	37.1%	37.1%	37.9%	37.6%	13.0%
RFC	161,600	156,700	216,300	222,100	223,800	232,354	270,200	27.6%	29.4%	30.0%	33.8%	32.6%	13.0%
RFC-MISO	52,985	51,360	70,714	71,138	72,732	74,016	79,461	27.4%	27.8%	29.4%	31.2%	30.6%	13.0%
RFC-PJM	108,525	105,660	142,022	147,368	147,459	154,772	187,144	25.6%	28.3%	28.3%	33.3%	31.7%	13.0%
SERC	206,639	200,181	244,553	260,941	278,873	278,873	291,793	18.1%	23.3%	28.2%	28.2%	28.2%	13.0%
Central	44,894	43,096	51,049	53,424	56,582	56,582	57,433	15.6%	19.3%	23.8%	23.8%	23.8%	13.0%
Delta	27,201	26,618	36,146	37,360	38,420	38,420	40,920	26.4%	28.8%	30.7%	30.7%	30.7%	13.0%
Gateway	17,212	17,137	23,604	24,702	25,502	25,502	25,502	27.4%	30.6%	32.8%	32.8%	32.8%	13.0%
Southeastern	50,298	48,182	59,194	66,009	75,242	75,242	81,048	18.6%	27.0%	36.0%	36.0%	36.0%	13.0%
VACAR	67,034	65,148	74,560	79,446	83,127	83,127	86,890	12.6%	18.0%	21.6%	21.6%	21.6%	13.0%
SPP	37,047	36,028	48,489	52,781	59,354	59,650	65,738	25.7%	31.7%	39.3%	39.8%	39.6%	13.0%
WECC	127,515	124,005	167,813	193,051	193,051	196,122	200,242	26.1%	35.8%	35.8%	37.4%	36.8%	12.1%
AZ-NM-SNV	23,221	22,476	37,055	39,481	39,481	40,958	43,169	39.3%	43.1%	43.1%	46.8%	45.1%	11.7%
CA-MX US	45,926	43,584	59,850	80,530	80,530	80,530	80,937	27.2%	45.9%	45.9%	45.9%	45.9%	13.3%
NWPP	47,639	47,292	56,749	57,687	57,687	58,200	58,961	16.7%	18.0%	18.0%	18.9%	18.7%	11.9%
RMPA	12,038	11,762	13,965	14,704	14,704	15,804	16,523	15.8%	20.0%	20.0%	27.5%	25.6%	10.5%
Total-U.S.	728,563	705,406	923,872	1,004,265	1,031,830	1,048,469	1,164,772	23.6%	29.8%	31.6%	33.2%	32.7%	13.0%
Canada													
MRO	8,789	8,528	9,011	10,399	10,399	10,719	11,467	5.4%	18.0%	18.0%	21.1%	20.4%	9.0%
NPCC	67,266	65,489	62,075	72,815	72,794	72,794	78,242	-5.5%	10.1%	10.0%	10.0%	10.0%	13.0%
Maritimes	5,765	5,338	6,266	7,176	7,176	7,176	7,240	14.8%	25.6%	25.6%	25.6%	25.6%	13.0%
Ontario	20,845	20,845	15,623	22,930	22,930	28,314	28,314	-33.4%	9.1%	9.1%	32.6%	26.4%	14.5%
Quebec	40,656	39,306	40,186	42,709	42,688	42,688	42,688	2.2%	8.0%	7.9%	7.9%	7.9%	9.1%
WECC	25,514	25,514	23,885	25,335	25,335	29,289	30,607	-6.8%	-0.7%	-0.7%	14.9%	12.9%	10.2%
Total-Canada	101,569	99,531	94,971	108,548	108,527	112,802	120,316	-4.8%	8.3%	8.3%	12.2%	11.8%	13.0%
Mexico													
WECC CA-MX Mex	1,842	1,842	2,055	2,054	2,054	2,917	2,917	10.4%	10.3%	10.3%	52.3%	36.9%	12.5%
Total-NERC	831,974	806,779	1,020,898	1,114,867	1,142,411	1,164,188	1,288,004	21.0%	27.6%	29.4%	31.3%	30.7%	13.0%

Attachment H

Southwestern Energy Company's (SWN) Comment to the Draft EIS

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Southwestern Energy®

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April 20, 2015

Plains and Eastern EIS
216 16th Street, Suite 1500
Denver, Colorado 80202
comments@PlainsandEasternEIS.com
Attention: Dr. Jane Summerson,
DOE NEPA Document Manager

By Overnight Mail and E-mail

Dear Dr. Summerson:

Pursuant to the notices published in the Federal Register on December 19, 2014, December 29, 2014, February 12, 2015, and February 13, 2015,[1] SWN Production (Arkansas), LLC (SWN-A) and DeSoto Gathering Company, LLC (DGC and, together with their publicly traded parent Southwestern Energy Company and its other subsidiaries, "SWN")[2] hereby submit comments on the draft Environmental Impact Statement (draft EIS) issued by the Department of Energy (DOE) on December 19, 2014 for the Plains and Eastern high-voltage direct current (HVDC) electric transmission project (Plains and Eastern Project or the Project) proposed by Clean Line Energy Partners LLC (Clean Line).

Southwestern Energy Company is an independent energy company primarily engaged, through subsidiaries, in natural gas and crude oil exploration, development, and production with a market capitalization of approximately $9 billion and is currently the fourth largest producer of natural gas in the lower 48 U.S. states. Its subsidiaries SWN-A and DGC have substantial operations and property interests in the Fayetteville Shale region of Arkansas, one of the most significant shale plays in the United States. The Fayetteville Shale, potentially holding upwards of 20 trillion cubic feet of natural gas, has been in active production since 2004 and currently produces upwards of 2.8 billion cubic feet per day, which is enough to supply approximately 28,000 American homes for one year. Production of domestic natural gas from regions like the Fayetteville Shale has significantly enhanced U.S. energy security and bolstered state and local economies.

The Plains and Eastern Project's proposed route, including all alternative routes under study in the draft EIS, would run directly through the Fayetteville Shale region, resulting in substantial adverse impacts to natural gas production. Disruption or curtailment of existing and future exploration and production operations would, in turn, significantly impact local, regional, and state economies. As explained in the detailed comments below, the draft EIS does not adequately address these impacts and:

[1] 79 Fed. Reg. 75,800 (Dec. 19, 2014); 79 Fed. Reg. 78,088 (Dec. 29, 2014); 80 Fed. Reg. 7,850 (Feb. 12, 2015); 80 Fed. Reg. 8,081 (Feb. 12, 2015).
[2] SWN-A is a natural gas exploration and production company and DGC is a natural gas gathering company. Both are subsidiaries of Southwestern Energy Company.

- Understates the full extent of natural gas infrastructure that will be adversely affected by the Plains and Eastern Project;

- Incorrectly concludes that impacts on natural gas development will be short-term and minimal;

- Fails to identify and analyze potential public safety impacts resulting from the operation of the HVDC line near natural gas infrastructure, including acceleration of corrosion of natural gas pipelines and impacts on electronic equipment; and

- Fails to analyze the socio-economic consequences of adverse impacts on natural gas development to the Arkansas economy on a state, regional, and local level.

SWN-A and DGC support the development of renewable energy sources and do not oppose transmission infrastructure to foster renewable development, but the Plains and Eastern Project should not be routed through the Fayetteville Shale. The size and importance of the Fayetteville Shale play, and the density of natural gas operations in the region, require that DOE consider and recommend as the "preferred alternative" a route outside of the play that would have significantly fewer impacts to shale development and, consequently, local, regional, and state economies.

The draft EIS also discusses matters related to the requirements of Section 1222 of the Energy Policy Act of 2005. SWN-A and DGC provide initial comments on these matters as they are addressed in the draft EIS, with the understanding that DOE will also notice a new public comment period specifically to consider Section 1222 issues.[3] These comments are provided without prejudice to, or limitation on, SWN-A and DGC's rights to submit additional comments on Section 1222 issues in the future or to raise matters related to the Plains and Eastern Project in another forum.

I. SWN-A's and DGC's Interest in the Fayetteville Shale

A. The Fayetteville Shale Generally

The Fayetteville Shale play is an unconventional underground natural gas reservoir spanning across north-central Arkansas within the Arkoma Basin. The play is approximately 9,000 square miles and is very active. Exploration and production activities occur throughout the play, with well pads, construction and production equipment, and an interconnecting web of gathering, intrastate and interstate natural gas pipelines densely deployed. Using the most up-to-date mapping tools available from the U.S. Energy Information Agency (EIA),[4] SWN-A and DGC provide the following maps to illustrate the expanse of the play as it concerns not just SWN but all companies involved in natural gas exploration, production, and transportation:

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[3] *See* DOE, Plains and Eastern Clean Line Transmission Project Draft EIS Public Hearings Presentation (Jan./Feb. 2015), at slide 24 (announcing the public comment opportunity for Section 1222 issues).

[4] EIA, Arkansas State Profile and Energy Estimates, Profile Overview Map, available at: http://www.eia.gov/state/?sid=AR. The maps provided as Figures 1 through 4 were created by using the Layers/Lend options to display the shale basin, shale play, natural gas wells, and major natural gas pipelines. The EIA indicates that the well data is current through November 2014 and the pipeline data through January 2012.

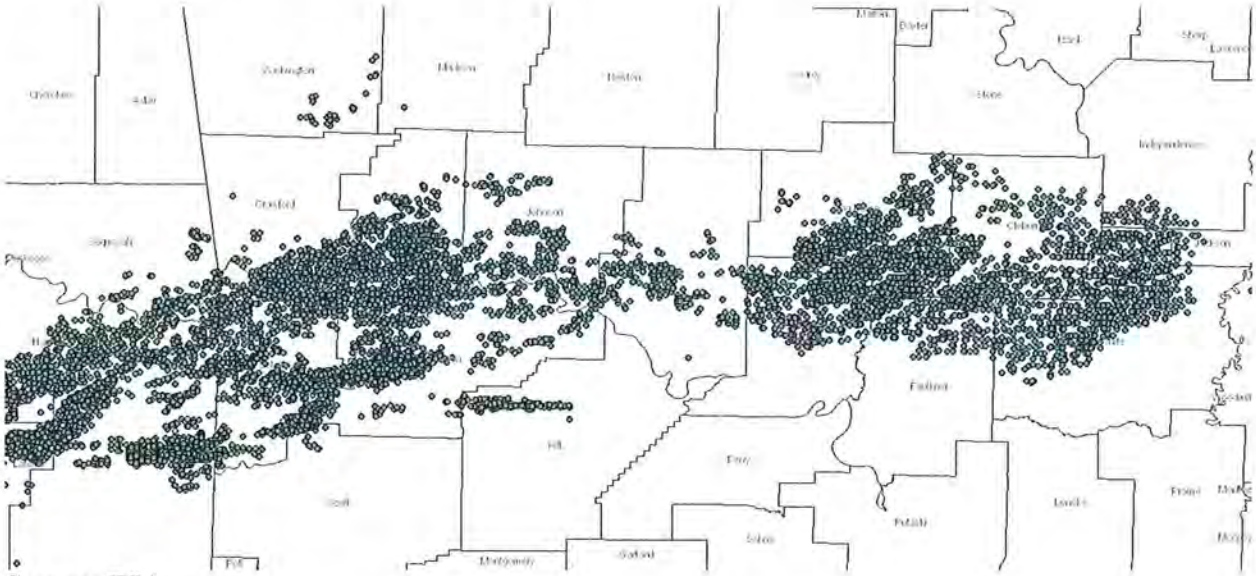
Figure 1: Fayetteville Shale play (brown shaded region east of the Arkansas-Oklahoma border) within the Arkoma Basin (lighter outline)

Source: EIA

Figure 2: Fayetteville Shale Play and Arkoma Basin, magnified view focusing on Arkansas.

Source: EIA

Figure 3: Location of natural gas wells in the Fayetteville Shale play



Source: EIA

Figure 4: Major interstate and intrastate natural gas pipelines (excluding gathering lines)

Source: EIA

As depicted in Figure 3, the number and density of wells in the Fayetteville region are substantial, with the EIA estimating a well count of over 3,200 as of May 31, 2011 in just the eastern part of the play.[5] For each well, a significant amount of land, equipment and infrastructure is required, both to drill and set up a producing well and to connect that well to the pipeline network.

[5] EIA, Surface Locations of Fayetteville Shale Wells (May 31, 2011), available at: http://www.eia.gov/oil_gas/rpd/shaleusa3_letter.pdf (depicting locations of wells in the eastern half of the play).

This work is dynamic as new well pads are set up, new wells are drilled on existing or new well pads, and existing wells are maintained or re-drilled.

- A typical well pad can measure 700 feet by 700 feet. Larger well pads may be required depending on site-specific conditions. Multiple wells can be drilled over time from the same well pad.

- Construction and production equipment on-site at a well pad over the course of its operation usually includes wells, 120-foot high drill rigs, tall cranes with 150+ foot booms, electric lines, compressors, pumps, flowlines, separation equipment and tanks, telecommunications towers, and enclosed structures.

- Construction equipment such as drilling rigs, cranes, and other equipment are moved from well pad to well pad through the play as needed and on a daily basis.

- Connecting each well to the natural gas pipeline system is a branch-like network of smaller-diameter gathering pipelines feeding into larger-diameter transmission pipelines, sometimes with the use of compressors. For this reason, Figure 4 above does not depict the full extent of pipeline infrastructure in the region, as it only identifies the transmission facilities which form the trunks to which the branched-out gathering lines are connected.

B. SWN-A's and DGC's Operations in the Fayetteville Shale

SWN-A's total proved reserves in the Fayetteville Shale play are estimated to be 5.1 trillion cubic feet, and SWN has leased approximately 764,287 total net acres to explore for and produce oil and gas. SWN-A has drilled over 4,578 wells since 2004 and as of December 31, 2014, has 4,027 total gross producing wells. Attachment A to these comments provides a map depicting SWN-A's wells in the eastern part of the Fayetteville Shale play. DGC operates over 2,107 miles of gathering lines in the play.

In 2014, SWN-A had a total net production of 494 billion cubic feet of natural gas and drilled 468 new wells, which represents a capital investment of $944 million. DGC gathered 812 billion cubic feet of gas in 2014. In 2015, SWN-A plans to drill 225-235 wells, which represents a capital investment of approximately $560 million. SWN-A has drilled 138 of those wells to date. Currently, 267,456 acres of SWN-A's leased acreage (approximately 34%) in the area remain undeveloped.

SWN-A and DGC emphasize that even a single well represents a significant investment and source of revenue. Taking into account the average cost of drilling and completing a well ($3.25 million), 2014 production costs, and current forward gas prices, an average well should generate considerably more than $2 million in profits. The well pads within the right of way for the Applicant Proposed Route host on average about three wells, which represents a profit of well over $6 million.

II. Description of the Plains and Eastern Project Route in the Fayetteville Shale

The Plains and Eastern Project is a proposed 3,500 megawatt (MW), 600 kilovolt (kV) HVDC transmission line that would run 720 miles from the Oklahoma Panhandle region to

Tennessee through Arkansas. DOE is currently considering whether to "participate" in the project under Section 1222(b) of the Energy Policy Act of 2005, and this potential federal participation requires DOE to prepare an EIS pursuant to the National Environmental Policy Act (NEPA). The EIS will, among other matters, assess the project's potential environmental impacts, identify alternatives and mitigation measures, and inform DOE's determination of whether the Plains and Eastern Project is in the public interest.

Regions 4 and 5 of the proposed transmission line would be located in the Arkansas River Valley and Central Arkansas respectively, passing directly through the Fayetteville Shale play. The draft EIS generally recognizes this fact and the high level of activity in the play, stating that:

> Portions of the Project traverse significant oil and natural gas fields, particularly the Anadarko Basin and Arkoma Basin (GIS Data Source: USGS 2005b). The western portion of the ROI (particularly in Regions 4 and 5) is located within a part of the United States that is experiencing a boom in natural gas production because of the use of hydraulic fracturing and horizontal drilling technologies. This new technology has made the recovery of shale gas economically viable.[6]

In addition to the route proposed by Clean Line, DOE also analyzes a number of alternative segments. Five of these segments are in Region 4 (Alternatives 4A-4E) and six are in Region 5 (Alternatives 5A-5F).[7]

III. The Plains and Eastern Project Will Adversely Impact Natural Gas Exploration, Production, and Gathering Activities in One of the Most Significant Shale Plays in the United States

Although the draft EIS recognizes that the Plains and Eastern Project will directly pass through the Fayetteville Shale, the Project's potential impacts on natural gas exploration, production, and gathering are greatly understated. The draft EIS also fails to identify and assess the adverse safety impacts the operation of a HVDC transmission line could have on pipeline and well infrastructure. The DOE should revise its analysis to incorporate the significant adverse environmental impacts that will likely result from the construction and operation of the proposed Project and assess the feasibility of routing the Plains and Eastern Project outside of the Fayetteville Shale play.

A. The Draft EIS Understates the Extent of Natural Gas Infrastructure in the Shale Play That Would Be Impacted by the Proposed Transmission Line

As a threshold matter, the draft EIS does not adequately identify the full extent of natural gas exploration, production, and gathering facilities that will be impacted by the Project. The draft EIS states that: "[t]he Applicant Proposed Route in Region 4 would traverse 1,929 acres of shale gas plays and six oil and gas wells. Ten oil and gas wells and 2,630 acres of shale gas plays are traversed in the Applicant Proposed Route representative ROW of Region 5."[8] This is a substantial

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[6] Draft EIS at p. 3.6-6.
[7] *Id.* at pp. 2-34 to 2-35.
[8] *Id.* at p. 3.6-25. The draft EIS also identifies infrastructure in a 4,000 foot-wide-corridor for all alternatives in Regions 4 and 5, finding 282 wells and 13,128 shale play acres in this broader corridor for Region 4, and 181 wells and 9,618 acres

understatement of the number of wells and associated infrastructure in proximity to the proposed transmission line.

SWN-A has undertaken an analysis of its own well pads in proximity of the Applicant Proposed Route and determined that 15 existing well pads and one well pad planned to be constructed later in 2015 are located wholly or partly within the 200-foot right of way for the proposed transmission line. SWN-A has drilled *33 wells* on these pads and at present plans to drill another 13 wells in the near future. Another 46 well pads (one of which is planned for 2015) are within 700 feet of the Applicant Proposed Route.[9] SWN-A has drilled 67 wells on those pads and at present plans to drill another 11 wells in 2015 and 2016. SWN-A has performed a similar analysis for the Project's alternate segments through the Fayetteville Shale play, and has found that 10 well pads (1 planned) and 23 wells (1 planned) are located within the 200-foot right of way. The transmission line would directly cross five of these pads and the 15 wells currently located thereon. Furthermore, 45 well pads (1 planned) and 121 (17 planned) wells lie within 700 feet of the right-of-way through these alternate segments along the route.

SWN-A's analysis above does not count either well pads leased or owned by other operators. It also does not include associated facilities such as ponds, impoundments, compressor stations, and telecommunication towers. For these additional reasons, the draft EIS substantially understates the operations that will be impacted by the Project.[10]

As explained above, each well pad is interconnected with a branched network of natural gas gathering and transmission pipelines, including compression facilities. The draft EIS recognizes that "[o]il and gas wells and their appurtenant facilities are very common throughout the ROI in Regions 4 and 5"[11] and that gas pipelines and electric transmission lines are located in or across the proposed right-of-way. These very generalized types of statements do not provide any meaningful assessment of the extent of gas pipeline infrastructure that will be impacted by the Project.

In the Tier IV Routing Study prepared by Clean Line in November 2013 and provided with the draft EIS, Clean Line estimates that, for Region 4, 5.53 miles of "transmission pipelines" are located in the 1,000-foot right of way and that there will be 12 "transmission pipeline crossings."[12] For Region 5, 24.73 miles of "transmission pipelines" and 47 "transmission pipeline crossings" are identified.[13] The dataset used by Clean Line (Ventyx 2013) is described as including interstate and intrastate transmission pipelines, but not gathering pipelines. DGC has undertaken an analysis of its gathering system and found that the proposed right-of-way for the Applicant Proposed Route would cross gathering pipelines *87 times*. Over two miles of DGC's gathering pipelines would fall within

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it places the proposed transmission line in context and more accurately represents the extent of infrastructure that will be affected because an actual right-of-way will typically fall within a variance. While these figures are included in the draft EIS, they are not relied upon in reaching any conclusion regarding the impact of the Project on natural gas development.

[9] SWN-A used a 700-foot distance because it represents the typical distance between a well and the farthest edge of the typically-sized well pad, *i.e.*, the work area/buffer zone required to drill and operate the well.

[10] SWN-A and DGC note that the number of wells, well pads, and associated facilities can be expected to continue to expand. With several years until construction is underway and complete, the extent of natural gas operations the proposed Project would encounter in the Fayetteville Shale at that time would be even greater than today.

[11] Draft EIS at p. 3.10-6.

[12] Clean Line Tier IV Routing Study (Nov. 2013), at pp. 67, 71.

[13] *Id.* at pp. 79, 83.

the 200-foot right-of-way. This analysis does not take into account re-routing of existing pipelines or the installation of new pipelines that may be required in the future. By failing to account for gathering pipelines, the draft EIS substantially underrepresents the extent of natural gas infrastructure that will be impacted by the Project.

B. The Draft EIS Inaccurately Concludes that Impacts to Natural Gas Exploration and Product Operations Will Be Temporary and Minor

While having an accurate count of natural gas infrastructure proximate to the proposed Project is critically important, an assessment of the proposed impacts of the Project on the operation of that infrastructure also is required. The draft EIS lacks this analysis. The draft EIS instead relies on a number of conclusory statements and open-ended and unenforceable "mitigation" measures to conclude that impacts on natural gas exploration and production operations will be minor. For example, the draft EIS states that "[o]ther short-term and local impacts include the disruption to access to local land uses that may occur, such as agriculture, oil and gas development, and residences and businesses during construction. The short-term impacts would be minimized, however, because of multiple [Environmental Protection Measures (EPMs)] incorporated into the Project."[14] These summary conclusions fall short of the level of analysis required by NEPA for three reasons.

First, impacts to natural gas development operations are unlikely to be "short-term and local." Fifteen of SWN-A's current well pads and 33 existing wells (plus one planned well pad and another 13 planned wells) are located within 200 feet of the transmission line along the Applicant Proposed Route. Of these, the transmission line would directly cross over eight of these well pads, which have a total of 17 existing and 13 planned wells. The resulting impact would be permanent cessation of production of the 46 wells on these pads and also to render them useless for drilling future wells.

Moreover, well pads located along the right of way can also be permanently affected. As explained above, construction and production activities are dynamic and involve use of the entire well pad tract. Equipment may be placed anywhere on the well pad depending on safety considerations, well locations, pit location, pipeline location, and road location. Siting a 3,500 MW HVDC line next to a well pad will interfere with drilling rig and crane activities due to the height of the equipment and proximity to the line. Even "a minimum stand-off of 250 feet from the edge of the route [rights-of-way]"[15] would not provide an adequate margin of safety for the operation of equipment, which can exceeds 120 feet in height. It would also not provide an adequate space to conduct operations if, for example, the well were located closer to the edge of the well pad abutting the right-of-way.

The draft EIS also does not acknowledge impacts to natural gas operations from impacts to other infrastructure. For example, the draft EIS indicates that the Project would cross or be located proximate to electric distribution lines and roads,[16] but fails to analyze how this proximity

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[14] Draft EIS at pp. 3.10-78 & 79. *See also* Draft EIS at p. 3.6-18 ("Project infrastructure would avoid impacts to active mineral resources features and would not preclude development of underground mineral resources in most cases.") & p. 3.6-41 ("Any short-term effects to access mineral resources are not expected to cause long-term impairment to the productivity of mineral resources.").
[15] Draft EIS at p. 3.6-41.
[16] *Id.* at p. 3.4-61.

will affect that infrastructure, including the extent that electric distribution lines and roads would need to be re-routed or blocked off. Further, the draft EIS does not consider how these impacts could result in a loss of the electric power source and physical access to a well pad. SWN-A has identified 15 locations where the right-of-way would cross access roads for well pads. Electricity from the local grid will also follow roads going to SWN facilities and will be placed on 20-foot tall poles, raising the potential for displacement or interference.

Second, in support of the conclusion that disruption would be minimal, the draft EIS assumes that:

> Oil and gas resources would be less affected because recovery of the resources would be possible, even with a minimum stand-off of 250 feet from the edge of the route [rights-of-way] and converter station sites using a vertically installed well without the use of directional drilling. With directional drilling, such areas could be accessed at considerable distances from the project.[17]

This conclusion is highly speculative. It assumes that there will be adjacent property available to move the well pad entirely or partly to a new location, or reconfigure the well on the existing well pad. However, many wells are currently sited in areas where the options for placement are constrained by existing development, protected wetlands, and Arkansas state regulatory requirements. Thus, moving or reconfiguring the well pad may be an impossibility or would result in unacceptable environmental, safety, or socioeconomic impacts. The draft EIS addresses none of these issues. Further, even if wells could be moved, SWN-A and other operators would have to obtain agreements from landowners, which would involve a new lease and additional expenditures. For these reasons, the potential use of directional drilling does not support the broad conclusion that impacts to natural gas development will be minimal.

Third, the mitigation measures considered in the draft EIS are inadequate. In the section on geology, paleontology, minerals, and soils, the following applicant-drafted EPMs are identified as ways to "specifically avoid or minimize the potential for impacts" on natural gas operations:

- GE-29: Clean Line will work with landowners and operators of active oil and gas wells, utilities, and other infrastructure to identify and verify the location of facilities and to minimize adverse impacts. Identification may include use of the One Call system and surveying of existing facilities.

- LU-1: Clean Line will work with landowners and operators to ensure that access is maintained as needed to existing operations (*e.g.*, to oil/gas wells, private lands, agricultural areas, pastures, hunting leases).[18]

Requiring Clean Line to "work" with operators falls short of requiring Clean Line to avoid impacts to natural gas operations and ensure access to well pads. Therefore, these EPMs do not provide a basis to conclude that impacts can be avoided or minimized. Even if Clean Line works in

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[17] *Id.* at p. 3.6-41.

[18] *Id.* at p. 3.6-15 to 3.6-16. This section also identifies additional EPMs (GE-1, GE-9, GE-27, GEO-1, and LU-3), but these do not appear applicable to natural gas operations.

good faith with SWN-A and other operators, it cannot be presumed that the transmission line could be re-routed locally to avoid impacts to natural gas operations, given the density of well pads and related infrastructure in the region.

B. The Draft EIS Fails to Identify and Study Critical Safety Issues Raised by the Potential Siting of an HVDC Transmission Line near Natural Gas Gathering Pipelines and Production Equipment

Proposing to site an HVDC transmission line near natural gas exploration, production and gathering infrastructure raises several critical safety issues that are not identified or analyzed in the draft EIS. These issues include pipeline safety considerations that will be of concern to the public and should inform DOE's public interest determination.

Hazards to Pipeline and Well Casing Integrity

The Plains and Eastern Project has the potential to jeopardize pipeline and well casing integrity through corrosion. Specifically, pipelines and well casings are susceptible to corrosion from stray current originating from the operation of HVDC transmission lines. As NACE International, a professional organization in the corrosion prevention field, has observed, "[b]oth the operation of bipolar HVDC transmission systems that use the earth as a conductor of transmission currents and monopolar systems that use earth return currents can have serious repercussions on underground metallic structures. Whenever stray DC interference current discharges directly into the ground, corrosion occurs."[19] Similarly, ASM International, a professional organization of metals engineers and scientists, has noted that "[c]orrosion of underground pipelines can be accelerated by stray [DC] flowing in the soil near the pipeline."[20] This same analysis would apply to other underground metal structures.

Clean Line proposes a metallic return for the entire length of the transmission line.[21] Although this metallic return may reduce stray current, it will not eliminate stray or excess current. As a result, stray current from the Plains and Eastern Project has the potential to adversely affect pipelines and casings by accelerating corrosion even under normal operating conditions. However, during abnormal operations which may be experienced from time to time, creation of grounded "imbalanced" DC currents could even more significantly impact pipelines and well casings.

The draft EIS does not address the potential corrosive impacts of the Plains and Eastern Project on pipelines and well casings nor the potential threat to pipeline integrity and safety that would result from accelerated corrosion. Moreover, the draft EIS does not analyze the potential risk of harm to pipeline facilities that would result if the metallic return is compromised, increasing the magnitude and frequency of stray current conditions. Given that corrosion can lead to pipeline failure, which in turn could result in death and property damage, the draft EIS is incomplete. DOE should require Clean Line to conduct an in-depth engineering study to analyze the impact of the Plains and Eastern Project on pipeline facilities, wells, and other metal conduits, including the levels

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[19] NACE International, High-Voltage Direct Current Interference, at p. 3 (May 2013).
[20] Beavers, J. A., and N. Thompson. 2006. "External Corrosion of Oil and Natural Gas Pipelines: Stray Current Corrosion." IN: ASM Handbook. Vol. 13C Corrosion: Environments and Industries. Materials Park, OH: ASM International, p. 1015–1025.
[21] Draft EIS, Appendix F, at p. 19.

and duration of stray current. SWN-A and DGC believe that the result of this analysis will demonstrate to DOE and the public that the Plains and Eastern Project should be routed outside of the Fayetteville Shale play.

Hazards to Electronic Equipment

With regard to operations equipment, SWN-A and DGC use computer, radio, instrumentation, satellite communications, and telecommunications equipment in the routine course of its activities. Manufacturers of this equipment have been unable to confirm to SWN-A and DGC that a 3,500 MW HVDC transmission line will not adversely impact the equipment's functionality, as it has not been tested under the electrical conditions that will be created by the transmission line. In addition to electrical conditions, telecommunications equipment could also be adversely impacted due to physical line-of-sight obstructions caused by the proposed transmission towers which could block radio signals. Due to the importance of electronic equipment to ensure safe operations, there is no room for interference or interruption from electrical conditions or line-of-sight obstructions.

As one example, a small computer known as a Remote Terminal Unit (RTU) is located on almost every well pad in the field. Among other functions, the RTU monitors the pressure at various points on the production equipment. Should the pressure rise above design limits, the well is automatically shut in. Interference with or failure of this system could result in an over-pressure condition that could lead to an explosion or fire. The RTU also monitors fluid levels in tanks which hold salt water produced from the well or water used to obtain gas production from the well. Interference with or failure of this system could result in an overflow condition that causes the discharge of such water into adjacent areas, including any environmentally-sensitive areas nearby.

Because of the critical importance of electronic equipment to the safety of SWN's personnel and operations, as well as the safety of the public, this issue should be identified and comprehensively studied by DOE. It is unlikely that these safety issues can be satisfactorily mitigated – which, again, would dictate that the Plains and Eastern Project be sited outside of the Fayetteville Shale play.

C. The Draft EIS Fails to Analyze the Socio-Economic Consequences that Would Result from Adverse Impacts to Natural Gas Exploration, Production, and Gathering

The development of the Fayetteville Shale provides significant socioeconomic benefits to the region and the State of Arkansas as documented in a recent report issued by the University of Arkansas Center for Business and Economic Research (Fayetteville Economic Analysis).[22] Specifically, the Fayetteville Economic Analysis estimates that "[i]n 2012, total economic activity of almost $4.0 billion and value added of almost $2.7 billion are projected to occur as a result of Fayetteville Shale in the state."[23] In the period from 2008 to 2011, "almost $2.0 billion in state and local taxes from permit fees and severance, property, income, sales, and other taxes were collected as

[22] U. of Ark. Center for Business and Econ. Research, "Revisiting the Economic Impact of the Natural Gas Activity in the Fayetteville Shale: 2008-2012 (May 2012), available at: http://cber.uark.edu/mwg-internal/de5fs23hu73ds/progress?id=-AeXNFuZll3CjOrY3iorWvb2v2Nw8fmNds7BdamA0EM.
[23] *Id.* at p. ix.

a result of Fayetteville Shale activities."[24] In the same time period, the total economic activity generated from Fayetteville Shale activities was estimated at more than $18.5 billion.[25]

Development of the Fayetteville Shale also has resulted in significant employment growth in this part of the state, and has led to "higher average annual pay, additional income received from mineral leases and royalty payments, and other induced impacts result[ing] in higher personal incomes, which lead to larger personal expenditures."[26] SWN contributed significantly to these regional benefits through, among things, the payment of nearly $2.5 billion in royalty payments, payroll, taxes, and charitable contributions since 2007. As a direct result of these economic benefits, funding for education and social services has increased and local governments have reduced or eliminated budget deficits.

As documented in detail above, the Plains and Eastern Project—as currently routed—could potentially disrupt development activities in the Fayetteville Shale. Among other things, companies like SWN-A would have difficulty siting new well pads or accessing existing well pads which, in turn, would substantially curtail the level of development in this region. Further concerns about the potential of the Plains and Eastern Project to adversely impact gathering pipelines and electronic equipment used in operations also could unnecessarily limit development activities.

As a consequence, the socioeconomic benefits of the Fayetteville Shale development likely would be significantly reduced. This could manifest itself in increased unemployment, reduced royalty payments, and declines in tax revenue. DOE's analysis of the socioeconomic impacts of the Plains and Eastern Project should consider the potential adverse impacts that would occur if the Project is sited through the Fayetteville Shale. In particular, DOE's analysis should address the reduced development that could result from siting an electric transmission line through an area that supports such a robust natural gas exploration and production industry, and quantify the resultant adverse local, state, and regional socioeconomic impacts that would occur as result of reduced shale play development.

D. Conclusion: The Plains and Eastern Project Should be Routed Outside of the Fayetteville Shale Play

DOE's analysis undertaken pursuant to NEPA must take into account potential adverse impacts on natural gas exploration, production, and gathering, including critically important safety issues and the socio-economic benefits that accrue from development of the Fayetteville Shale in Arkansas. As it stands, the draft EIS does not adequately identify and address these issues. Such an analysis also will be central to DOE's public interest review,[27] as DOE must weigh whether locating the proposed Plains and Eastern Project in the heart of the Fayetteville Shale can be justified given the likely adverse economic impacts to the State of Arkansas, local economies, and businesses such as SWN that have propelled economic development and job creation in this region.

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[24] *Id.* at p. viii.
[25] *Id.* at p. v.
[26] *Id.* at p. v. and i.
[27] DOE, Request for Proposals for New or Upgraded Transmission Line Projects under Section 1222 of the Energy Policy Act of 2005, 75 Fed. Reg. 32,940, at 32,941 (Jun. 10, 2010) (referred to herein as the "DOE Notice") (stating that DOE will consider "[w]hether the Project is in the public interest").

SWN-A and DGC appreciate that DOE has analyzed alternative segments in Regions 4 and 5 but, as DOE itself concedes, these alternatives will also impact natural gas exploration, production, and gathering.[28] SWN-A's analysis set forth above at page 7 also demonstrates that substantial natural gas infrastructure is located on the alternative segments. Thus, the fact remains that routing alternatives located in the shale play would still have unacceptable adverse impacts. This is true even for an alternative in the play with comparatively fewer well pads located along the segment because impacts to even just a few well pads can be substantial. As explained above, a well pad hosting an average of three wells generates a profit of well over $6 million. Moreover, the identified routing alternatives cannot avoid shale play acreage. The draft EIS acknowledges that an average of 62% (Region 4) to 95% (Region 5) of the area that would be impacted by both the route proposed by Clean Line and all the alternatives analyzed is part of the "shale gas play."[29]

Because of the size and importance of the Fayetteville Shale play to the regional economy and U.S. energy security interests, and the density of natural gas operations in the region, DOE should consider an alternative route, outside of the play, which would have significantly fewer and smaller impacts to shale play development and, consequently, local, regional, and state economies. Such an alternative also would prevent future conflicts between natural gas operators and Clean Line as new planned wells are drilled and undeveloped areas in the play are developed in the years ahead.

IV. Other Issues Raised by the NEPA Process and the Draft EIS

A. DOE Participation under Section 1222

Section 1222(b) of the Energy Policy Act of 2005 authorizes DOE to "design, develop, construct, operate, maintain, or own, or participate with other entities in designing, developing, constructing, operating, maintaining, or owning, a new electricity power transmission facility and related facilities," provided certain statutory requirements are met.[30] DOE indicates that it will decide whether to participate "in one or more" of those ways.[31]

Based on publicly available information about the Plains and Eastern Project, it appears that Clean Line will own and operate the transmission line on a merchant-basis, retaining all revenues generated, with no ownership or invested capital by DOE or other governmental agencies. In other words, the Project does not appear to be a public-private partnership with a direct exchange of benefits between Clean Line and DOE. SWN-A and DGC request that DOE clarify the manner in which it will "participate" in the Project.

B. Section 1222 Requirements for Proposed Projects

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[28] Draft EIS at p. S-52 (recognizing that all alternatives will have impacts on shale gas deposits, even though particular alternatives may have greater or fewer potential impacts).
[29] *Id.* at p. 3.6-10 to 3.6-11.
[30] 42 U.S.C. § 16421(b).
[31] Draft EIS at p. S-20.

In the draft EIS, DOE acknowledges that the "purpose and need for agency action is to implement Section 1222. To that end, DOE needs to decide whether and what conditions it would participate in the Applicant Proposed Project."[32]

Section 1222 conferred upon DOE new authority to utilize third-party financing for transmission projects. Section 1222(b) of the Act authorizes DOE, acting through and in consultation with the Southwestern Power Administration (SWPA), to participate in new electric power transmission projects with third parties provided certain criteria set forth in the statute are met. Among the statutory criteria, DOE must determine that the Plains and Eastern Project "(A) is located in an area designated under section 216(a) of the Federal Power Act [16 U.S.C. 824p(a)] and will reduce congestion of electric transmission in interstate commerce; or (B) is necessary to accommodate an actual or projected increase in demand for electric transmission capacity."[33]

With regard to this requirement, the Plains and Eastern Project is not located in a Section 216(a) corridor, and thus must demonstrate that it "is necessary to accommodate an actual or projected increase in demand for electric transmission capacity."[34] The demonstration of whether the Plains and Eastern Project is necessary to accommodate increased demand should be explored more fully in the final EIS. Based on available information, Clean Line conducted an open solicitation for the transmission capacity on the Plains and Eastern Project almost a year ago but has yet to announce any contractual commitments evidencing a strong commercial interest in the project. The potential lack of commercial interest in the Project should be a factor analyzed as part of DOE's determination of whether the Project is meeting a defined need for new capacity.

In addition to the statutory criteria that DOE is required to address under Section 1222, the DOE Notice stated that DOE will use additional criteria to evaluate the Plains and Eastern Project. These criteria include a determination of whether the Project is in the public interest and an assessment of the "benefits and impacts of the Project in each state it traverses, including economic and environmental factors."[35] Therefore, the final EIS should specifically identify and assess the impacts of the Plains and Eastern Project on Arkansas, with a specific focus on its proposed route through the Fayetteville Shale. Given the potential for the Project to adversely affect existing and planned shale play development activities, and the attendant socioeconomic impacts that will result from such effects, Arkansas-specific impacts must be analyzed in greater detail. The draft EIS does not adequately assess how the Plains and Eastern Project could justify the potential harm to Arkansas and U.S. energy security interests if routed through the Fayetteville Shale. Further, as stated earlier, DOE's analysis of alternatives should include project routes outside of the Fayetteville Shale.

The DOE Notice also states that DOE will assess the Project's "technical viability" and "financial viability." [36] With regard to the former, DOE should carefully consider the issues raised above regarding the potential adverse impacts of HVDC transmission lines on pipelines, well casings, and electronic equipment. With regard to the latter, in the event DOE and SWPA may permissibly exercise eminent domain authority in connection with the Project, the costs of doing so can be expected to be substantial if the transmission line is routed through the Fayetteville Shale play.

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[32] *Id.* at p. S-2.
[33] 42 U.S.C. § 16421(b)(1).
[34] *Id.* at § 16421(b)(1)(B).
[35] DOE Notice at 32,941.
[36] *Id.*

The interests of both surface and numerous oil and gas and other mineral holders will need to be negotiated or litigated. As a result, the length and complexity of condemnation proceedings will be multiplied. Moreover, the cost of condemning those interests will be far higher than if the line were routed through an area that does not contain a high concentration of valuable oil and gas and other mineral development.

C. Section 1222 and State Siting Requirements

Section 1222(d) also expressly provides that nothing in Section 1222 "affects any requirement of: (1) any federal environmental law, including the National Environmental Policy Act of 1969, [pursuant to which DOE prepares an environmental impact statement]; (2) any Federal or State law relating the siting of energy facilities; or (3) any existing authorizing statutes."[37] Section 1222, therefore, does not preempt state siting requirements. Accordingly, Clean Line will be required to obtain applicable state authorizations for the siting of the transmission line (*e.g.*, a public utility commission certificate of public convenience and necessity or certificate of environmental compatibility and public need).

In a proceeding before the Arkansas Public Service Commission (PSC), the PSC noted that "Clean Line has acknowledged that there will be a future [Certificate of Environmental Compatibility and Public Need (CECPN)] proceeding." Consequently, Appendix C to the draft EIS ("Potential Federal and State Permits and Consultation Required for the Project") should include the CECPN proceeding under the list of Arkansas regulatory proceedings.

D. Notice to Underground Property Interest Holders

SWN-A and DGC appreciate the efforts that the DOE has undertaken to inform the public and other stakeholders about the Plains and Eastern Project following the release of the draft EIS through public meetings, presentations, and other means.

For its part, Clean Line mailed notices to surface property owners adjacent to the Project. No such notices, however, were received by SWN-A or DGC, which are record owners of oil and gas leases and pipeline rights-of-way.[38] In many instances, a surface owner leases its surface or minerals to natural gas operators such as SWN-A, and those operators would not receive notice in such an event. Regardless, oil and gas leases and other conveyances of mineral interests are recorded in each county in Arkansas, and such records are readily obtainable. In a unique region such as the Fayetteville Shale play, Clean Line should have provided early and direct notice to sub-surface interest holders. This raises the question of how many natural gas operators, pipelines, and other parties with sub-surface interests in the vicinity of the Project have not been adequately or timely notified or remain unaware of the Project's existence.

As a practical matter, Clean Line also should have undertaken early, direct outreach to SWN-A, DGC, and other natural gas and pipeline operators in the Fayetteville Shale play. Given the extent of natural gas development in the play, it would have been prudent to hold discussions with the

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[37] 42 U.S.C. § 16421(d).

[38] Another SWN company owns some small tracts of land for surface facilities and did receive notice.

natural gas operators to discuss the feasibility of the proposed routing, safety concerns, and other matters.

V. Requested Actions

SWN-A and DGC appreciate this opportunity to provide DOE with comments on the draft EIS for the Plains and Eastern Project. SWN-A and DGC request that DOE consider and recommend as the "preferred alternative" a route outside of the Fayetteville Shale play that would have significantly fewer impacts to shale play development and, consequently, local, regional, and state economies. Accordingly, DOE should: (1) revise its NEPA analysis to accurately reflect potential impacts on natural gas infrastructure and operations, (2) analyze the potential hazards to pipeline and well casing integrity and electric equipment, (3) study the socio-economic consequences that would result from adverse impacts to natural gas development, and (4) address the Section 1222 and public notice issues raised herein.

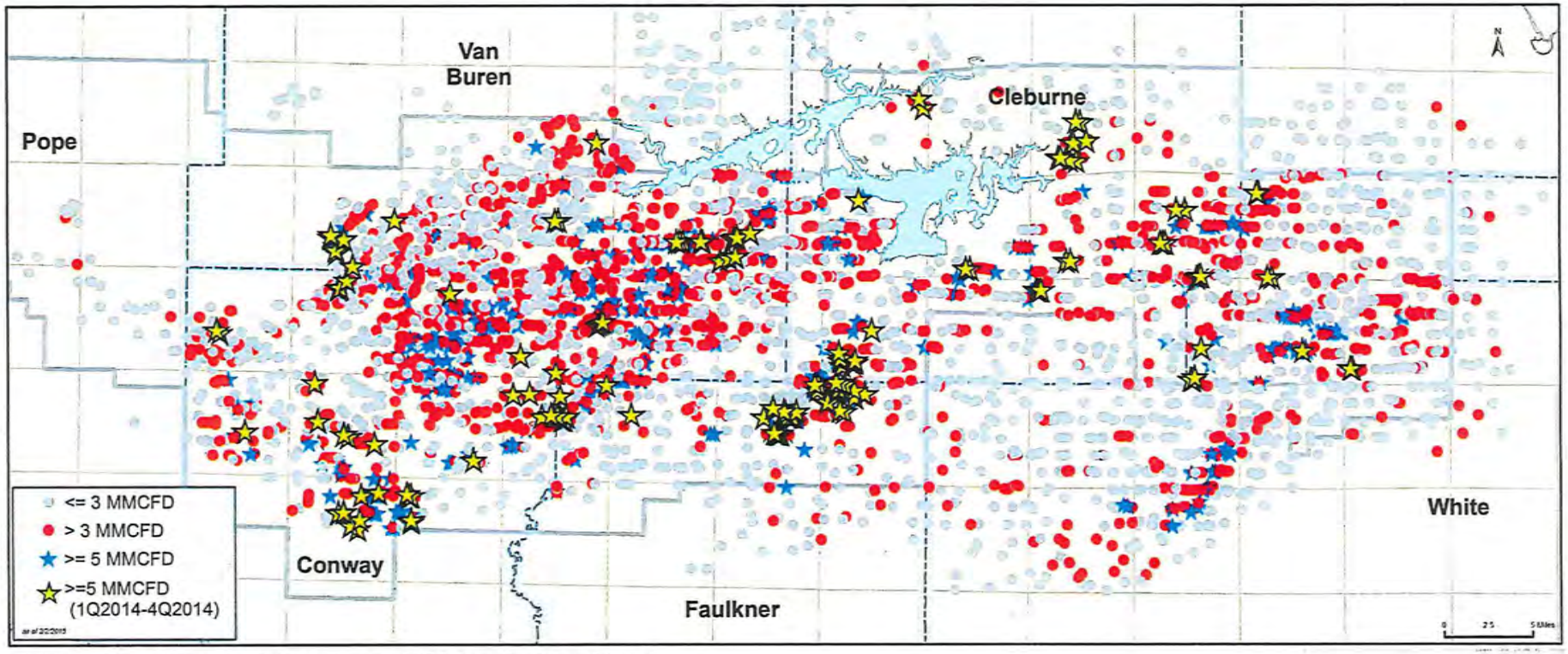
Please do not hesitate to contact the undersigned if SWN-A and DGC can provide further information regarding this matter.

Very truly yours,

John C. Ale
Senior Vice President, General Counsel & Secretary
SWN Production (Arkansas), LLC and
DeSoto Gathering Company, LLC

Fayetteville Shale Focus Area

swn
Southwestern Energy



Notes: Data as of December 31, 2014. Rates are AOGC Form 13 and Form 3 test rates.

- SWN holds approx. 888,000 net acres in the Fayetteville Shale play.
- SWN discovered the Fayetteville Shale and has first mover advantage – average acreage cost of $320 per acre with a 15% royalty and average working interest of 74%.
- 24 of the top 30 wells based on highest initial producing rates were drilled in 2014.
- We plan to drill approximately 225 to 235 operated horizontal wells in 2015.

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Attachment I

Southwestern Power Resources Association

Comment to the Draft EIS

SOUTHWESTERN POWER RESOURCES ASSOCIATION

SPRA

Representing Federal Hydropower Interests in
Arkansas Kansas Louisiana Missouri Oklahoma Texas

April 16, 2015

Dr. Jane Summerson
NEPA Document Manager
Plains & Eastern Clean Line EIS
216 16th Street, Suite 1500
Denver, Colorado 80202

Dr. Summerson,

This letter sets forth Southwestern Power Resources Association's (SPRA) comments and response to the Draft Environmental Impact Statement (DEIS) for the Clean Line Plains and Eastern Project (the Project). As outlined below, SPRA has identified many risks and/or liabilities associated with the Project. DOE and Clean Line need to develop a clear plan to mitigate these and any other risks or liabilities to both Southwestern Power Administration (Southwestern) and its customers.

SPRA is a voluntary, not-for-profit organization of rural electric cooperatives and public power systems in Arkansas, Kansas, Louisiana, Missouri, Oklahoma and Texas. These systems are customers of Southwestern, headquartered in Tulsa, Oklahoma, which markets hydroelectric power generated at 24 multi-purpose Army Corps of Engineers water projects in this region. SPRA members serve over 8,200,000 end-users in this six state region with clean, environmentally-friendly Federal hydropower. The Flood Control Act of 1944 (58 Stat. 887, 890; 16 U.S.C.A. 825s) is Southwestern's main authorizing legislation. Through Section 5 of this Act and a series of Executive Orders, Southwestern's Administrator is authorized to "transmit and dispose of ... power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles."

Southwestern is also authorized to draw up rate schedules for such power and energy, with the goal of recovering, with interest, the investment of the American people. These rates, which repay ***all*** of the costs of Southwestern, are paid by its customers. While Southwestern receives a small amount of appropriations every year from Congress, these appropriations plus all other expenses for itself and for the US Army Corps of Engineers' (Corps) costs for hydropower and a percentage of joint use expenses are included in the rates that the customers pay. The customers are ultimately the only funding stream for Southwestern. Therefore, the customers must be carefully insulated from any project utilizing Section 1222 of the EPAct 2005 (42 USC 16421), such as the current Project contemplated under the DEIS.

Section 1222 authorizes the Secretary of Energy, acting through and in consultation with the Administrator of Southwestern (provided the Secretary determines that certain statutory requirements have been met), to participate with other entities in designing, developing, constructing, operating, maintaining, or owning new electric power transmission facilities and related facilities located within any state in which Southwestern operates. Section 1222 sets forth the following criteria for evaluating a project:

1. Whether the Project is necessary to accommodate an actual or projected increase in demand for electric transmission capacity.

2. Whether the Project is consistent with transmission needs identified, in a transmission expansion plan or otherwise, by the appropriate Transmission Organization if any, or approved regional reliability organization.

3. Whether the Project is consistent with efficient and reliable operation of the transmission grid.

4. Whether the Project will be operated in conformance with prudent utility practice.

5. Whether the Project will be operated by, or in conformance with the rule of, the appropriate Transmission Organization, if any, or if such an organization does not exist, regional reliability organization.

6. Whether the Project will not duplicate the functions of existing transmission facilities or proposed facilities which are subject of ongoing or approved siting and related permitting proceedings.

In June, 2010, the DOE issued an RFP (75 Fed. Reg. 32,940) which listed the following additional criteria for evaluating a project under Section 1222:

1. Whether the Project would be in the public interest.

2. Whether the Project would facilitate the reliable delivery of power generated by renewable resources.

3. The benefits and impacts of the Project in each state it traverses, including economic and environmental factors.

4. The technical viability of the Project, considering engineering, electrical, and geographic factors.

5. The financial viability of the Project

According to the DEIS, the Project is defined as a 750 mile overhead ± 600kV High Voltage Direct Current (HVDC) electric transmission system and associated facilities with the capacity to deliver approximately 3,500MW primarily from renewable energy generation facilities in the Oklahoma and Texas Panhandle regions to load-serving entities in the Mid-South and Southeast United States via an interconnection with the Tennessee Valley Authority in Tennessee. Section 2.4.3.1 of the DEIS also describes a "DOE

Alternative" of an additional converter station in Arkansas which would be capable of interconnecting 500MW. Clean Line has obtained a certificate of public necessity to operate as a public utility in Oklahoma. To date, Clean Line has not obtained a public utility status in Arkansas. In January of 2015, the Tennessee Regulatory Authority (TRA) approved Clean Line's application for a certificate of Public Convenience and Necessity. TRA also bestowed on Clean Line the authority to operate as a wholesale transmission-only public utility in Tennessee. In FERC Docket No. ER12-2150-000 (140 FERC 61,187) FERC describes the Project as a merchant transmission project as distinguished from a traditional public utility transmission project. The developers of a merchant transmission project assume all market risks and have no captive customers from whom to recover the costs of the Project.

Due to Arkansas' refusal of Clean Line as a public utility, it is SPRA's understanding that Southwestern will be required to own all of the land rights, as well as the facilities of this Project in that State. Additionally, it is SPRA's understanding that when developing the Oklahoma portion of the Project, Clean Line will negotiate the purchase of land for easement purposes. Any tracts of land that cannot be purchased through negotiations Clean Line will ask Southwestern to acquire that property through the exercise of its eminent domain authority as an agency of the Federal government. When Southwestern does so, it will be required to own that portion of the facilities of the Project. The result will be a patchwork of title and facilities ownership where some of the land rights and facilities will belong to Clean Line and some will belong to Southwestern (The United States of America) throughout the State of Oklahoma.

SPRA's foremost concern is that none of the costs or risks associated with the construction or implementation of the Project is passed to Southwestern or its customers. This Project is outside the scope and ordinary course of business of Southwestern as authorized under Section 5 of the Flood Control Act of 1944, which is the marketing of Federal hydropower. Southwestern's customers should not have to pay for these costs. SPRA has identified several areas of potential risks or liabilities for this Project that are discussed below. Both Clean Line and the Department of Energy must formulate a mitigation plan to insulate both Southwestern and the customers against these risks and liabilities. This plan must clearly identify how all of these and any other costs will not be passed to Southwestern or its customers before any decision can be reached by the Secretary of Energy about whether to proceed with this Project under Section 1222.

Right of way acquisition for the Project is the first concern of SPRA. SPRA is concerned about the legal challenge to the right for the government to condemn land for this Project and about the hefty expenses associated with the actual acquisition of the land. Since it is SPRA's understanding that Southwestern will own at least half of the land rights, the Department of Justice (DOJ) will have to act on behalf of Southwestern to use eminent domain to acquire these land rights if the courts have adjudicated that eminent domain can be used for Section 1222 projects. DOJ will more than likely be challenged on its right to condemn land for this Project. The Takings Clause of the Fifth Amendment of the Constitution sets forth two requirements that the Federal government must meet before it can take a citizen's property. First the property must be taken for a public use and, second, just compensation must be paid. If Southwestern does exercise its condemnation authority, the "public use" element will be challenged. As previously discussed, under Section 5 of the Flood Control Act of 1944, Southwestern has a very narrow mission. Section 5 authorizes Southwestern to market and transmit hydroelectric power generated at Corps owned projects. Section 5 also authorizes Southwestern to construct and/or acquire ***only*** such transmission lines and related facilities that are necessary to market the hydroelectric power received from the Corps.

If Section 5 does not give Southwestern the right to exercise eminent domain for this Project, one must look to Section 1222 for this right. The law is not explicit about the use of eminent domain. Additionally, this Project is the first to contemplate using Section 1222, so there is no precedent to rely upon. Generally, one can look to previous uses of eminent domain for guidance. The most applicable case is Path 15, which Western Area Power Administration (Western) finished constructing in 2004. In that case, the Secretary of Energy directed Western to develop plans to upgrade Path 15, an 84 mile 500kV transmission line in the San Joaquin Valley. Congress authorized Western to upgrade the line and appropriated funds for its design and development. Western constructed the upgrade in partnership with Pacific Gas and Electric Company and Trans-Elect New Transmission Development. Western maintained a 10% share of the project, which is used for the benefit of Western's system. Western exercised its right of eminent domain and land owners challenged the authority to exercise eminent domain as well as the "public use" element.

The Ninth Circuit Court found numerous citations to laws and to statutes where Congress authorized Western to construct the project and wherein Congress appropriated funds for the project design and construction. Therefore the court held that Western had the necessary authority to take the property interests that were the subject of the hearing. Secondly, the court addressed the "public use" requirement. The court, quoting from the U.S. Supreme Court decision in *Kelo v. City of New London*, 545 U.S. 469, 477 (2005), stated "the sovereign may not take the property of A for the sole purpose of transferring it to another private party B, even though A is paid just compensation." "It is only the taking's purpose, and not its mechanics that matters in determining public use," ID at 482 (quoting *Haw. Hous. Auth. v. Midkiff*, 467 U.S. 229, 244 [1984]). Since the Path 15 project did not entail a private-to-private transfer and since Western retained a 10% share of the project, the court concluded that the Path 15 project satisfied the "public use" requirement (*United States v. 14.02 Acres of Land More or Less in Fresno County*, 530 F.3d 883, 9th Cir. 2008). However, unlike the Path 15 case, there is no explicit Congressional authorization for the Clean Line Project, nor have there been Congressional appropriations for it. Additionally, Southwestern will not own capacity of the line, but will own the land rights and the project facilities in all of Arkansas and portions of Oklahoma. This ownership will not benefit Southwestern's system for the delivery of Federal hydropower. As contemplated, there will be no private-to-private transfer of property. To prevent costly and lengthy litigation which can monopolize the resources of Southwestern, careful and deliberate legal analysis should be done to determine if the authority to condemn land exists in Section 1222, and if this Project will meet the "public use" requirement set out in the Fifth Amendment of the Constitution, and further defined in the cases set forth above.

If it is determined that the authority exists to condemn land for this Project, Clean Line and DOE must ensure that the customers of Southwestern and/or the taxpayers do not finance this acquisition. Clean Line must be required to reimburse Southwestern/DOJ for both the time spent acquiring this land, as well as for any payments that the government is ordered or required to pay as compensation for land rights.

If the Secretary of Energy approves the Project and land is acquired, there are new areas of risk and/or liability which must be addressed. First is the issue of third party claims for injury to persons or property. If during development or construction activities, or during the operation of maintenance of the Project, the activities of Clean Line or its contractors results in injury to either persons or property, Southwestern or its customers cannot be liable for any resulting claims. Additionally, if there is a third party claim for injury for any reason associated with the Project such as defective structures, faulty engineering, breach of contract for either facilities or power supply, or for any other reason, the

customers of Southwestern cannot finance these legal proceedings or awards. This will be particularly tricky because of the requirement that Southwestern own the land rights and the facilities of at least half of this Project. SPRA needs to see a clear and precise plan, through both contract language and mitigation measurements including but not limited to letters of credit and insurance policies, which fully shields Southwestern and its customers from this risk. Second, a clear plan needs to be in place to ensure that Clean Line pays for all legal expenses associated with any other activity of the Project, including property disputes. Additionally, Clean Line needs to pay for property taxes and any other taxes associated with this Project, even though Southwestern is expected to own large portions of it.

In addition to the concerns stated above, there are further issues with the Project during the construction phase which need to be addressed. According to the maps in the DEIS, the Project crosses or parallels many of Southwestern's transmission lines, as well as many lines of SPRA members/customers of Southwestern. All construction work for this Project must be done in such a manner as to ensure there is not damage to any of these neighboring facilities or lines. If such damage occurs, full compensation for facility repair as well as losses due to outages must be paid to the owner of the lines from Clean Line. During construction, Clean Line must be fully responsible for ensuring that its activities comply with all Federal, state, and local permitting requirements.

Of further concern, if the Project is not completed for any reason once construction has begun, whether due to bankruptcy of Clean Line; non-performance by any of the parties under contracts; cost overruns rendering the Project financially nonviable; equipment supply issues; or for any other reason, Southwestern and its customers cannot be required to complete the Project and/or provide service under the contracts. If the Project is in mid-construction and not completed, Clean Line and DOE need to have not only clear contractual language, but mitigation measures such as letters of credit and insurance policies to ensure that there are enough funds to decommission the Project without looking to the customers or the taxpayers for these funds. Particularly in the case of bankruptcy, these funds will not be available after the fact, so they must be set aside and accounted for before construction begins for the Project. Also to address the possibility of bankruptcy, a plan needs to be in place if the Project's financiers foreclose on the Project either during or after construction. Southwestern does not want to be left owning a noncontiguous transmission line from which it does not obtain any benefits. Due to the nature of this Project as a merchant line, as opposed to a traditional public utility transmission project, special attention must be paid to the situations where Clean Line becomes insolvent and Southwestern is left with facilities it cannot use and does not need.

If the Project completes construction, there are additional risks and/or liabilities identified by SPRA. Currently SPRA has seen no identification of who will operate and maintain this Project. This is a HVDC line, which is very different from the Alternating Current (AC) lines of much lower voltage that Southwestern currently owns, operates, and maintains. If Southwestern were to operate and maintain this line, substantial staff would have to be hired, and equipment would have to be purchased. Currently, Clean Lines pays for the time that Southwestern's staff dedicates to the Project. However, this still has a detrimental impact on the customers. Southwestern must currently use its existing resources which were employed to fulfill the core mission of the delivery of Federal hydropower to also work on this Project. The natural consequence is that less time can be dedicated to its core mission and serving its customers. Any costs, including the ongoing costs of staff time and the hiring of additional employees, must be paid by Clean Line. If another company is used for operations and maintenance, they must meet all standards required by Southwestern to ensure compliance with all applicable laws, regulations, and those standards set forth by the North American Electric Reliability Corporation (NERC). Regardless of who operates and maintains this Project, Clean Line must be strictly liable for all NERC

compliance and costs associated with compliance. This is including but not limited to registration, compliance for all NERC standards such as reporting and audits, and fines or mitigation measures which may be assessed as a penalty.

Furthermore, SPRA needs to see clear contractual language which ensures that both Southwestern and its customers are not held responsible for any loss of service or curtailments for Clean Line's customers. This Project traverses an area which is frequently known for both tornados and ice storms. Southwestern and SPRA members experience loss of service from time-to-time due to these natural disasters. If for any reason Clean Line faces this unfortunate circumstance, or their power is curtailed to their customers, Southwestern and its customers should not be required to fulfill any obligation of Clean Line.

Finally, SPRA would like to see the determination of the analyses, and the studies done on the Project under every criterion set forth in Section 1222 and 75 Fed. Reg. 32, 940 (both listed on page 2 of these comments). In particular, SPRA asks that DOE carefully study whether the Project is in the public interest and the technical and financial viability of the Project. Given the cost of the Project (projected at around ***$3.5 billion***), and the substantial risks which could flow to both Southwestern and its customers, these studies should be comprehensive and exhaustive. This is a mammoth Project, and SPRA asks that it is given the meticulous evaluation that a Project of this size requires.

In conclusion, the customers of Southwestern, represented here by SPRA have serious concerns about the risks and/or liabilities associated with this 750 mile, $3.5 billion Project. We ask that each of the concerns mentioned above is thoroughly considered before any decision is made by the Secretary about moving forward with this Project. Additionally, SPRA asks that both DOE and Clean Line guarantee that none of the costs of this Project, either now or in the future, are passed to Southwestern or included in its rates to its customers. This includes but is not limited to costs for additional staffing, litigation costs, land acquisition costs, decommissioning expenses, or any other costs. Also, SPRA needs to see specific mitigation measures such as letters of credit and insurance policies in place before any shovel of dirt is turned on the Project. Thank you for the opportunity to comment on this DEIS and I look forward to working collaboratively with DOE in the future to ensure these concerns are addressed.

Sincerely,

Brett Bradford
President of SPRA

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Attachment J

Oklahoma Office of Attorney General DEIS Comment

OFFICE OF ATTORNEY GENERAL
STATE OF OKLAHOMA

April 20, 2015

Sent via email to: comments@PlainsandEasternEIS.com

Plains & Eastern EIS
216 16th Street, Suite 1500
Denver, Colorado 80202;

Re: Oklahoma Attorney General's Office Comments on the DOE Plains and Eastern Environmental Impact Statement

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In 2010, the Department of Energy ("Department") issued a call for proposals of transmission line projects. Clean Line Partners LLC filed a proposal for the creation of a Plains and Eastern Clean Line ("the Line") to deliver power from renewable wind energy generation in the Oklahoma and Texas panhandles to the southeastern United States. The project would largely be dedicated to moving energy generated in Oklahoma to consumers several states away in the Southeast. While considering whether it should participate in the development of the Line, the Department has gathered information on the environmental impact of the project under the National Environmental Policy Act and its implementing regulations. Pursuant to these legal obligations, the Department published a draft Environmental Impact Statement for notice and comment. The draft Statement finds that no major environmental consequences would result from the development of the Line. This letter comments on that draft Environmental Impact Statement, criticizing its preparation and conclusions on three major grounds: 1) it did not result from a sufficiently inclusive process, 2) it does not give sufficient attention to significant environmental impacts resulting from the construction and maintenance of the Line, and 3) it has serious impediments that favor the No Action alternative available to the Department.

The development of the Line as well as the draft Environmental Impact Statement did not meet the expectations of an inclusive, community-driven feedback process we expect from administrative agencies. Landowners in Oklahoma did not have sufficient opportunity to have meaningful input on the route of the Line, and significant communities have been ignored. For example, the Tribal Council of the Cherokee Nation has passed a resolution opposing the Line. The Town Council of Vian, Oklahoma, also passed a resolution opposing the Line. Groups have even organized on Facebook—including the Block P and E: Plains

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and Eastern "Clean" Line group. These facts show that the project has not been seriously conformed to input received on the Line.

The lack of adequate process is particularly troubling given the actual state of power generation in the Oklahoma and Texas panhandles. No wind farms have yet been built to supply the Line with wind energy. There should not be any rush to complete this process, and landowners as well as tribal and local communities should have greater opportunities to be included in routing decisions because of the ample time available.

The most disturbing aspect of this process and the way it ignores the input of the community is that the State of Oklahoma will bear the brunt of tax subsidies helping to finance the wind generation in the Oklahoma panhandle. Yet that clean energy will not go to Oklahomans: it will be delivered to customers several states away, such as in Tennessee. If the State of Oklahoma can be expected to help pay for the power generation involved here, the process should involve more than *lip service* to Oklahomans' input on the route of any related transmission lines.

The draft Environmental Impact Statement notes several environmental consequences from the construction of the Line. It may result in changes or damage to land use, including to agriculture; deleterious air emissions; significant noise; and have negative impact on wildlife and vegetation. Not enough attention has been paid to some of these important impacts. Large transmission line towers and the cables running between them may disrupt the ordinary patterns of migration of many of Oklahoma's wildlife and bird species. Such disruptions may result in unnecessary animal and bird deaths or relocation. Further, many parts of the Line's route through Oklahoma travel through heavily forested areas. The transmission towers and cables, along with the requirements of their construction, could lead to the destruction of significant numbers of trees in these forests. These are not an easily replaced heritage in our State. The route of the Line should be reconsidered to avoid all such old growth forests in Oklahoma.

Soil is a precious resource in Oklahoma. The draft Statement does not give sufficient attention to the impact the construction of the line may have on the soil resources along the proposed route, nor are there adequate safeguards being considered to prevent soil erosion. These changes may result in reduced or eliminated productivity for prime agricultural land in Oklahoma. Productive farmland may not be able to be used agriculturally because of the presence of transmission towers, access roads for maintenance, and converter stations. The Line's route proposal should be reconsidered to avoid prime agricultural land and reduce this significant environmental impact. Likewise, the plan does not consider the impact on sub-surface mineral resources and their opportunity for development.

Water also represents a key concern in Oklahoma, particularly in the western part of the State where a large portion of the Line will run. Changes in land use, particularly during construction of the line and converter stations, could negatively impact runoff into rivers and streams. Such negative impacts on western Oklahoma's water resources may have notable ripple effects on wildlife by, for example, destroying habitats; it could also negatively impact

agricultural land uses. These effects could be magnified by contamination of groundwater along the route of the Line. Hazardous materials, fluids, or fuels could spill into Oklahoma's waterways, decimating the viability of the region's already scarce water resources.

Another significant environmental impact has not received sufficient attention in the draft Statement. Many Oklahomans make a serious, intentional decision to enjoy a rural lifestyle because of the freedom it allows them in their property usage, the scenic beauty they can enjoy every day, and because of the peace and quiet they obtain. Oftentimes these Oklahomans have significant parts of their personal assets tied up in their property, and the value of that property is directly tied to the aesthetic quality, quiet, and freedom available there. Particularly during the *years* of construction anticipated during this project, the Line will also bring loud noises and increased traffic. The Line thus threatens to ruin the most important qualities of rural life for many Oklahomans, reducing both the quality of life reasons for choosing their residences' locations in the first place and reducing their property values. Tall transmission line towers will not have a positive environmental impact for many affected Oklahomans.

Finally, there are serious obstacles that should prevent this project from proceeding with Department support. Section 1222 of the Energy Policy Act of 2005 requires that a project "will reduce congestion of electric transmission in interstate commerce" or "is necessary to accommodate an actual or projected increase in demand for electric transmission capacity." 42 U.S.C. § 16421(b)(1). The Line does not satisfy these requirements because there is no indication that the Southwest Power Pool or that the areas served by the Tennessee Valley Authority suffer from any congestion that this will alleviate—actually, additional construction will have to be completed in Tennessee to prevent the Line from adding reliability and congestion problems. Further, the only demand to be served by the Line will be demand Clean Line attempts to drum up itself. It is surely a suspect move to use government support for a transmission project where the anticipated demand for the project is being secured largely because of the transmission project itself being completed.

Perhaps the strangest aspect of using Section 1222 to justify Department support of this project is that no aspect of this project will benefit the energy grid in Oklahoma. Section 1222 only authorizes Department support for projects in the Southwestern and Western power areas. *See* 42 U.S.C. § 16421. But, ultimately, the energy grid being benefited by the Line will be in the southeastern United States. The Department would be using legal authority granted with a clear purpose to benefit particular power systems in order to provide benefits to another, completely different power system. Such an exercise of authority would be beyond what the statute grants.

Further, the Department should not proceed with the use of the federal government's eminent domain power mainly for the benefit of a private company. The Line's private developers should be able to negotiate themselves for property necessary for the development of the Line or, in the alternative, should be able to navigate the legal framework of Oklahoma before engaging in the serious exercise of property seizure within the state. This is particularly so when there is no compelling and immediate need for transmission

capacity from western Oklahoma to the southeastern United States. Hence, the Department should take no action and decline to participate in development of the Line, it should reconsider many of the negative environmental impacts to which it has not given enough attention, and it should make use of a more inclusive process for considering the input of Oklahomans.

Thank you for the opportunity to comment.

Sincerely,

P. Clayton Eubanks
Deputy Solicitor General