Electric Reliability in Michigan: *The Challenge Ahead*

Public Sector Consultants' research on electric reliability in Michigan is composed of two major works: this report and analysis, and a summary of findings titled "Electric Reliability in Michigan: A Policy Brief," which is intended to highlight the important elements of the full report. Both were released on Wednesday, November 19, 2014.

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Executive Summary

Michigan faces a near-term challenge of ensuring an adequate supply of electricity for its residents and businesses. This is not just an issue in Michigan; across the country, potential shortfalls in generation supplies are impacting more that 66 million customers (1). This issue is caused by a lack of adequate resources to meet consumer demand at all times. As soon as 2016, the retirement of aging coal plants (driven by federal environmental regulations and high costs) will cause Michigan's electric reserve margins to dip below target levels. Federally regulated wholesale markets established over a decade ago have failed to ensure adequate resources to meet customer needs in Michigan, the Midwest, and throughout many parts of the country.

Michigan's hybrid market structure[1] complicates the state's ability to address its capacity needs. The current regulatory framework creates uncertainty for energy providers as to which customers need to be served and when. Due to the hybrid market structure, some customers avoid paying the utilities' resource planning costs, which makes it difficult to ensure adequate energy supply. While reforms were made to Michigan's retail electric market in 2008 to mitigate some of these concerns, a fundamental flaw in the state's electricity market structure remains: no entity has been clearly assigned the responsibility for ensuring adequate, long-term supplies for customers participating in electric retail open access. An incumbent utility[2] is obligated to provide service in a nondiscriminatory manner to customers that return to their service from retail open access.[3] But in order to ensure that generating capacity for such customers is actually available when needed (while maintaining reliability), the utility has to purchase or build new capacity—potentially years in advance and at a substantial cost. The planning, permitting, and construction of new base load generation[4] could take as long as six years by some estimates (2). Additionally, purchasing capacity may become difficult because the cushion of excess generating supply in the Midwest region will begin to disappear in 2016. The requirement to serve an unknown customer base inhibits accurate planning and causes the regulated utility to operate at a higher cost. Absent reform, the current hybrid market structure will either place reliability at risk (assuming the utility does not plan generation to meet the needs of current retail open access customers) or unfairly shift additional costs of new capacity to the utility's existing customers, while a small fraction of customers served by retail energy marketers get a free ride.[5] This flaw has existed since PA 141[6] was enacted, but it has become a more pronounced and direct threat to reliability, given the significant number of imminent power plant retirements in the region and the resulting impact on capacity supplies and prices. The challenges created by Michigan's market structure is especially evident in the Upper Peninsula (see Issue in Focus on page 17).

Although greater reliance on energy efficiency, strategic reductions in energy demand, out-of-state energy purchases, and renewable sources can help bridge the supply gap, even aggressive efforts in those areas will not eliminate the need for new base load power plants to replace lost capacity. Given the long lead times and large capital investments required to plan and build base load plants, the state needs to establish the policy framework to address this impending supply problem in a way that is reliable,

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[1] Combining elements of traditional regulated utilities with aspects of retail electric competition.
[2] Incumbent utilities are those that supplied electricity to customers located in an exclusive service territory prior to passage of the reforms in PA 141 and PA 142.
[3] Subject to any return-to-service provisions (such as a 12-month notice requirement) in the utility's tariff, as applicable.
[4] The amount of electricity needed to sustain the basic energy demands, henceforth referred to as "generation."
[5] According to the MPSC Commissioner John Quackenbush, "The nearly 11 percent load participation in the choice market today translates into 0.3 percent of total customers for DTE and 0.06 percent for Consumers Energy. The current rate structure essentially transfers fixed costs no longer recoverable from customers participating in choice to all remaining customers." (See *Readying Michigan to Make Good Energy Decisions: Electric Choice.* Available at www.michigan.gov/documents/energy/electricc_report_440539_7.pdf, accessed 10/14/14)
[6] Michigan Public Act 141 of 2000, "Michigan Customer Choice and Electricity Reliability Act."

affordable, and fair for Michigan residents and businesses. For a brief summary of highlighted elements of this report, see the policy brief version of “Electric Reliability in Michigan,” available online at www.pscinc.com.

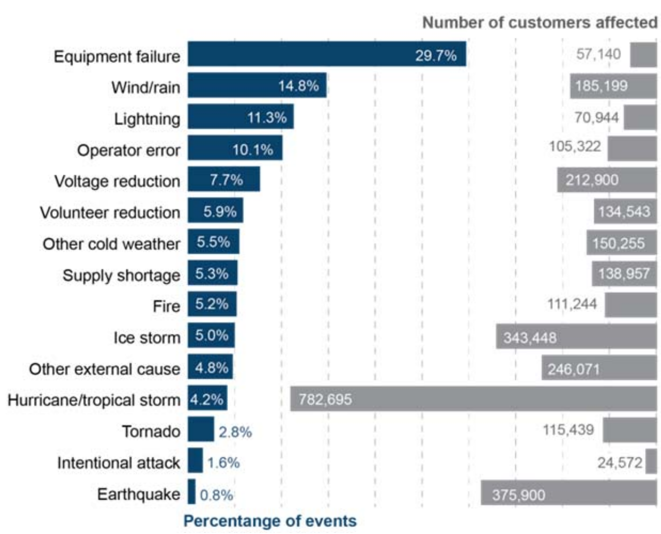
The Importance of Reliability

Electricity is such a fundamental aspect of everyday life that its importance and accessibility are often taken for granted—until it isn’t available. It is during those times of crisis that we can clearly see our dependence on electricity and our expectations about its essential reliability.

Disruptions to the availability of electricity are not mere inconveniences—they can cause suffering, fatalities, and financial losses, as well as lasting effects on the overall economy. The Northeast Blackout of 2003, which originated in Ohio, was caused by a software problem that left operators unaware of the need to redistribute power after overloaded transmission lines hit unpruned foliage. Fifty million people in eight U.S. states—including Michigan—and ten million people in Ontario were affected as 508 generating units at 265 power plants shut down. It resulted in the loss of power to six million Michigan residents for up to two days (3,4). Michigan’s economy also lost an estimated $1 billion when businesses were forced to shut down and industrial production stopped. Detroit Metropolitan Wayne County Airport halted operations; General Motors was forced to close its warehouses; Ford Motor Company’s production offices, engineering, and product development facilities ground to a halt; and Marathon Oil Corporation’s Detroit refinery lost 76,000 barrels per day of output (5).

There are many possible reasons for power outages, as shown in Exhibit 1. Weather-related incidences are the most common cause of electric outages. Michigan residents and businesses recently experienced a series of severe storms in the summer of 2014 that downed local distribution lines, causing outages, as did ice storms in December 2013.

EXHIBIT 1. Major Causes of Power Outages



SOURCE: Paul Hines, Jay Apt, and Sarosh Talukdar, n.d. *Trends in the History of Large Blackouts in the United States.* Available at http://wpweb2.tepper.cmu.edu/ceic/PDFS/CEIC_08_01_thl.pdf. (accessed 10/13/14)
NOTE: The totals are greater than 100 percent because some records fall into multiple initiating-event categories.

Supply shortages represent a relatively small percentage of all the causes of power outages. This is not an accident. Utilities are required to plan for adequate supply to meet consumer demand at virtually all times. This is known as “resource adequacy.” This planning is challenging, given that electricity must be produced as needed, since storage capacity is both costly and limited.[7] Moreover, the quantity of electricity needed varies depending on the time of day, time of year, weather, economic conditions, and other factors. Operators must consider these diverse factors to plan and operate power plants and the transmission grid so that demand and supply match exactly at all times, in all places. To accomplish this, a reserve margin, or “cushion,” is calculated to generate supplies above forecasted demand. Typical reserve margins are set at 14–15 percent; these are determined through annual reliability studies.[8]

While uncommon, outages caused by supply shortages can be serious. In Texas, in February 2011, an adequate supply of power was not available to overcome the combination of a cold snap and unplanned generation shutdowns. In the same year, Texas experienced a “supply emergency” due to record-setting heat and high-peak demand during the month of August. The multiple blackouts of California during its energy crisis of 2000–2001 were also caused by supply shortages. Those supply shortages in California were influenced by many factors, including a severely flawed attempt at industry deregulation, market manipulations by Enron, and historical difficulties in building new generation facilities in a state experiencing rising demand for electricity (6).

The Evolution of Regulatory Policy and Its Impact on Ensuring Adequate Electricity Supply

The regulatory framework and market structure in which electric utilities operate impacts their ability to ensure adequate capacity to meet demand. Changes in energy law, policy, and regulation over the past century have moved the electric utility industry toward more competition, less regulation, and increased federal influence (7).

State Oversight of Utility Resource Planning

For most of the 20th century, utilities were regulated monopolies that were vertically integrated—meaning the utility owned and operated generation assets, the transmission network, and the local distribution network required to deliver electricity throughout its geographic service area. In return for their monopoly status, utilities accepted an obligation to serve all customers who requested service and were willing to pay the regulated rates. This is commonly referred to as the regulatory compact.[9] This regulatory framework made ensuring resource adequacy fairly straightforward: utilities would forecast future demand, request approval from the state regulator to recover any new generating capacity costs through rates (in advance of construction or after), and be eligible to earn a return based on the cost of service.

[7] While technologies continue to advance, the only economic, grid-scale storage technology available is hydroelectric pumped storage. In most cases, constructing significant storage facilities requires substantial upfront costs and consumes more than one megawatt hour (mwh) of energy to store one mwh of energy (See Frank Wolak, March 31, 2013, *Regulating Competition in Wholesale Electricity Supply*, 17. Available at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/regulating_wholesale_electricity_wolak_mar08-final.pdf, accessed 10/10/14)

[8] In accordance with the Midcontinent Independent System Operator (MISO) Tariff, the reliability objective of a Loss of Load Expectation (LOLE) study is to determine a minimum planning reserve margin that would result in the MISO system experiencing a less-than-one-day loss of load event every ten years. (See MISO Resource Adequacy Studies, available at www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacyStudies.aspx, accessed on 10/10/14)

[9] In 1914, the Michigan Supreme Court affirmed the right of a public utility to use the streets in exchange for the corollary obligation to serve the public. (See City of Lansing v Michigan Power Co., 183 Mich 400, 410; 150 NW 250 (1914).)

When generation exceeded or fell short of local demand, utilities could sell or purchase power at wholesale to or from neighboring utilities, with rates also based on the cost of service (1, p. 26–27). This was true across the country and in Michigan. During this time, Michigan's two largest utilities, Consumers Power and Detroit Edison (currently Consumers Energy and DTE Energy), procured generation resources and collaborated to dispatch generation and transmission systems. Preparing for the possibility of short-term capacity shortages or high generating costs, they purchased energy from utilities in Ohio, other neighboring states, and Canada.

State level regulation left a large gap in transactions that occurred across state lines (7, p. 33). Amendments made in 1935 to the Federal Power Act (FPA) addressed this gap. These amendments gave jurisdiction to regulate interstate transactions (transmission of electricity and sale of electricity wholesale) to the Federal Power Commission (now the Federal Energy Regulatory Commission, or FERC). While this created a role for the federal government in utility regulation, the FPA made it clear that the preexisting regulatory authority of the states over generation and distribution facilities was preserved. More specifically and germane to this paper, ensuring generation resource adequacy and reliability was the states' responsibility. The FPA is still the primary federal law governing the electric utility industry.

Increased Federal Intervention

Rapidly increasing global oil prices in the 1970s contributed to higher operating costs for utilities, causing them to petition state regulators to approve rate increases. Economic forecasters anticipated that fuel prices would continue to rise over subsequent years, resulting in new investments by utilities in nonfossil fuel generation. During the 1970s and 1980s, utilities built more than 50 nuclear plants responsible for generating over 100 gigawatts (GWs)[10] under the assumption that fossil fuel prices would continue to rise (8). Investments in capital-intensive nuclear power plants created significant rate increases for consumers, and despite declining global oil prices, rates remained high (9, p. 37).

Political pressures mounted in response to high electricity costs, leading to more regulatory scrutiny of proposed generation. Some state and federal regulators—following a general trend at that time toward deregulation of industries like railroads, airlines, finance, and natural gas—envisioned that competition in both wholesale and retail electricity markets would yield lower costs to achieve the same service. To this end, in 1978, Congress passed the Public Utility Regulatory Policies Act. Among other things, it mandated that utilities purchase energy from qualifying facilities[11] owned by entities other than the vertically integrated incumbent utilities (7, p. 34). The introduction of new electric generators through wholesale electric utility restructuring created an issue of access to regional transmission networks. In an effort to ensure nondiscriminatory access to existing transmission lines owned by utilities, FERC suggested the creation of independent system operators (ISOs) (10). FERC expanded the ISO model to regional organizations, creating the regulatory framework for new regional transmission organizations (RTOs) (11). FERC outlined specific goals for RTOs, including improving efficiencies in grid management, grid reliability, and market performance, as well as removing discrimination in transmission systems. Exhibit 2 shows the different RTOs across North America.

[10] Depending on various factors, 1 GW would typically provide power to 750,000 homes. Consumers Energy, for example, lists the Electric Generating Capacity at its Campbell plant in west Michigan as providing 1,450 megawatts—or 1.45 GWs—enough to meet the energy needs of a million people.
[11] There are two types of qualifying facilities: (1) a small power production facility (generating facility) of 80 MW or less whose primary energy source is renewable (hydro, wind, or solar), biomass, waste, or geothermal resources, and (2) a cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy.

EXHIBIT 2. Regional Transmission Organizations

SOURCE: Sustainable FERC Project, n.d., "ISO RTO Operating Regions." Available at http://sustainableferc.org/wp-content/uploads/2013/10/ISO-RTO-Operating-Regions.jpg. (accessed 10/13/14)

States Implement Retail Restructuring

The deregulation of retail energy markets at the state level followed the federal move to deregulate, but in a less uniform manner. Industry restructuring was first adopted in 1996 by states with high retail electricity rates, including California, New York, New Hampshire, Rhode Island, and Pennsylvania (9, p. 48). Soon, states across the country began evaluating the potential for restructured electricity markets. By 1999, the District of Columbia and 20 states had undertaken the process to restructure their electricity markets (9, p. 44). Deregulation models shared several common characteristics across states, including: allowing for the recovery of utility stranded costs[12]; market pricing for wholesale electricity; unbundling traditional utility services; and creation of wholesale markets to support competition in supply markets. Despite similar design elements, each state's experience with industry restructuring has been unique. To date, 13 states and the District of Columbia have maintained their model of electric deregulation. Meanwhile, five states—Arizona, Arkansas, Nevada, New Mexico, and Virginia—have opted to suspend their deregulated markets (12). Three states—California, Michigan, and Montana—have opted for a hybrid electricity market, combining elements of traditional regulated utilities with aspects of retail electric competition (13).

Michigan's Unique Approach to Restructuring

Michigan entered into the world of retail open access with the passage of PA 141 in 2000, which allowed customers to purchase their generation needs from an alternative energy supplier—often referred to as retail energy marketers—at a market rate. Michigan approached deregulation differently than other states in that it did not force separation of utility-owned generation from their regulated distribution system during the restructuring process. The incumbent utilities continued to operate regulated generation and provide distribution service, but had to allow unregulated retail energy marketers access to their distribution system. As a result, Michigan exhibits characteristics of both a regulated market and a deregulated

[12] Stranded costs are utility charges that were to be recovered over time through regulated rates that would not otherwise be collected from customers served by retail energy marketer.

market. PA 141 also required regulated utilities to divest their transmission facilities or join an RTO (14).[13] In 2002, Michigan's major transmission systems joined the Midcontinent Independent System Operator (MISO) RTO; however, a small portion of southwest Michigan served by American Electric Power Ohio (AEP Ohio), joined MISO's neighboring RTO, PJM Interconnection (PJM).

Michigan Reevaluates its Energy Policy

Following summers with a tightly constrained power supply market and the Northeast blackout in August 2003—among other factors—the Michigan Public Service Commission (MPSC) initiated an investigation in late 2004 to examine future electric generation capacity requirements and, specifically, "the need for additional generation capacity, transmission upgrades, and other supply- and demand-side resources to supplement current Michigan-based generating facilities and out-of-state power sources" (15, p. 2). The investigation resulted in *Michigan Capacity Need Forum: Staff Report to the Michigan Public Service Commission,* which found Michigan would need additional electric supply to meet its needs beginning in 2009, and recognized the institutional barriers referenced above that impede the development of reliable electric supplies. Specifically, the report said:

> The electric energy industry has experienced several major changes during the past ten years. These include the creation of an open access transmission system, the development of independent transmission companies, the implementation [of] Midwest Markets, and provision of retail customer choice in Michigan. These changes, **especially the advent of retail customer choice**, have added uncertainty to any load serving entity's customer base. The uncertainties created by customer choice and changes in the wholesale markets have made generation construction, especially base load, more difficult to finance. It is unlikely that either traditional utilities or independent power producers (IPPs) will build additional base load generation without some departure from past practices for regulatory approval and rate treatment (16).

Following the release of that report, Governor Jennifer Granholm issued Executive Directive 2006-2, which directed the chairman of the MPSC to prepare an energy plan for the State of Michigan. The resulting *Michigan's 21st Century Electric Energy Plan* echoed the findings of the Capacity Needs Forum report with regard to the challenges presented by Michigan's market structure and recommended policy changes to overcome them (17). To stabilize the utilities' customer base and provide regulatory certainty for utilities to plan and finance new generation, the plan recommended a new regulatory framework that allowed electric utilities to file an application with the MPSC to obtain a "Certificate of Need" for construction of a new power plant before it is built. Once the MPSC granted the certificate, the necessity of the new power plant could not be challenged. It was the MPSC's determination that all customers contributing to the need for a new plant be required to pay their share of the costs. To ensure this, incumbent utility customers that later elect service from a retail energy marketer would be required to take their share of the plant's fixed cost with them as a non-bypassable distribution charge. For retail energy marketer customers wishing to return to the incumbent utility, the plan recommended the MPSC require a returning customer give the utility 60 days' notice before they could be returned to regulated service. Finally, the plan recommended that the MPSC have the authority to require planning reserves for all jurisdictional utilities, electric cooperatives, and retail energy marketers in the state, and the ability to penalize these entities if they fail to meet reserves.

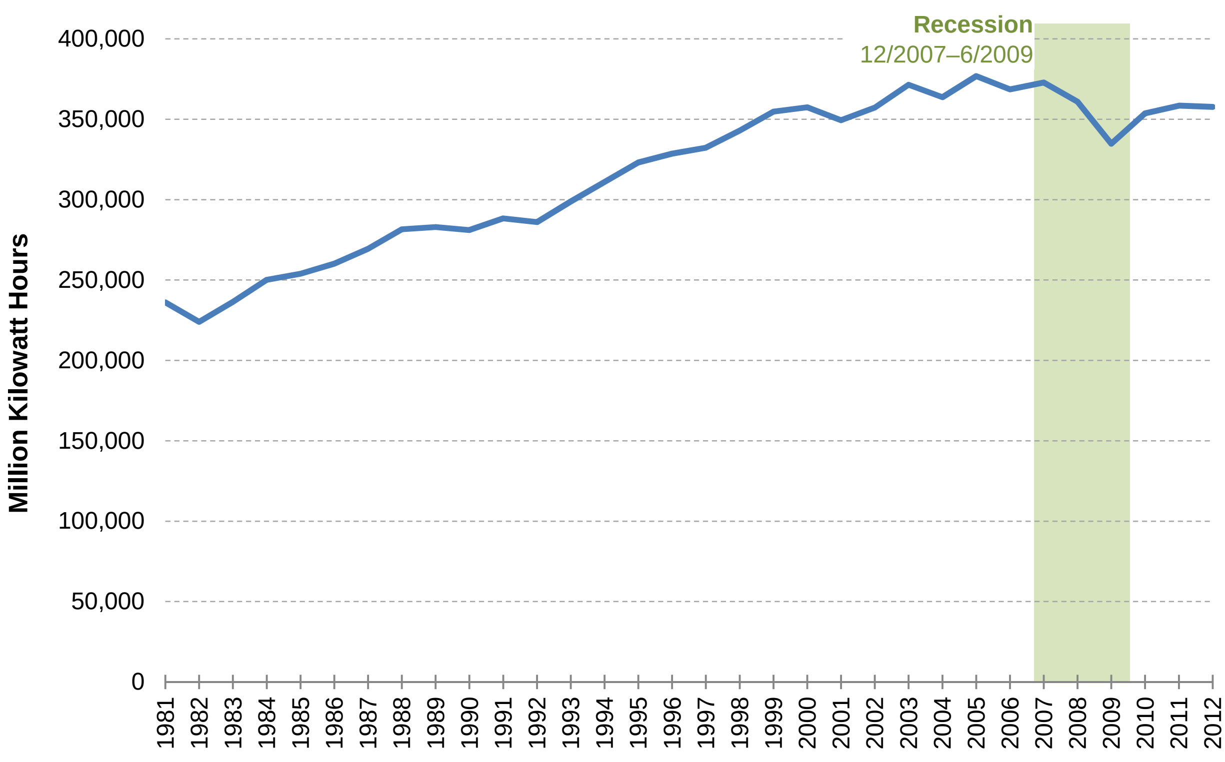
[13] Although utilities were required to do only one, both occurred.

Retail Restructuring Reforms Attempt but Fail to Address the Challenge

In response to the findings of this report, the Michigan Legislature passed reforms to Michigan's energy policy as part of comprehensive energy package. Included in these reforms was Public Act 286 of 2008, which partially included the Certificate of Need approach recommended in the plan—requiring approval for construction of a new power plant before it is built. Absent from this approach was the inclusion of the non-bypassable distribution charge for customers moving to retail open access after approval or extended lead times for those returning. In addition, in an effort to improve stability for energy providers, Public Act 286 placed a cap on the number of customers served by retail marketers, limiting it to 10 percent of the state's electric load.

While these reforms drastically reduced the percentage of a utilities load that could switch back and forth between retail energy marketers and regulated utilities (from 100 percent to 10 percent), the challenges of ensuring reliability within this hybrid market structure remained. In other words, the problem was not solved, only minimized. Until now, this has been less of a concern because, at the same time that these reforms were passed, a national economic recession hit that dramatically reduced demand for electricity, as shown in Exhibit 3. The predicted capacity shortfalls that drove the reforms did not transpire and, therefore, there has not been a need to invest in new generation. This is no longer the case. A number of factors currently are creating the need for new generation, driven in large part by significant retirements of coal-fired power plants across the Midwest.

EXHIBIT 3. Electricity Consumption in Michigan



SOURCE: U.S. Energy Information Administration. *State Energy Data System (SEDS): 1960-2012 (Complete).* Available at: www.eia.gov/state/seds/seds-data-complete.cfm?sid=US#CompleteDataFile. (accessed on 10/28/14)

Factors Threatening Reliability in Michigan

While many factors can influence reliability, the pressing challenge that Michigan faces is the need to ensure it has adequate generation resources. The shift away from coal as the primary fuel source for electricity generation, due to environmental regulations, is driving near-term supply shortages.

Environmental Regulations and Aging Infrastructure Impacting the Coal Industry

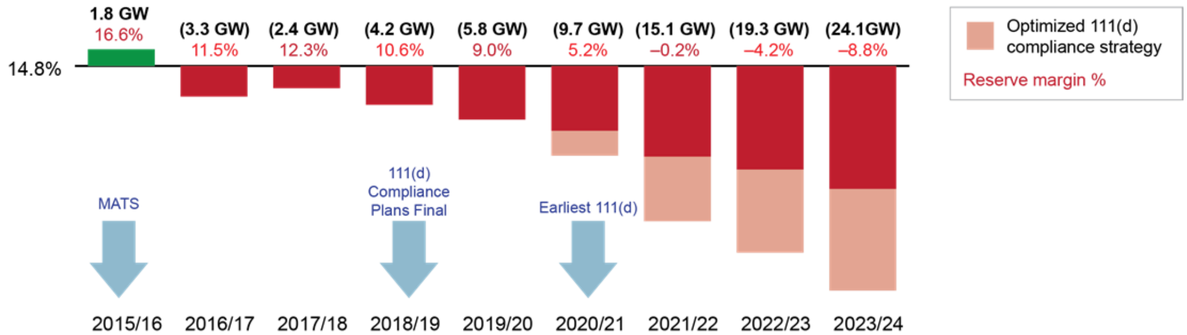
A primary factor in the changing landscape for electric generation is environmental regulations, both existing and proposed. For example, in 2015, the new Mercury and Air Toxins Standards (MATS) of the Environmental Protection Agency (EPA) will require coal plants to have pollution mitigation technologies in place to limit emissions.[14] In fact, the Energy Information Administration's *Annual Energy Outlook 2014* reports that 90 percent of coal retirements over the next six years will coincide with the first year of MATS enforcement (18). The MATS rule is having by far the largest impact on electric generators, but other regulations are also affecting the industry in the near term. New standards for the Cross-State Air Pollution Rule (CSAPR), Coal Combustion Residuals (CCR), and Cooling Water Intake Structures (CWIS) are expected to impact existing power generators.

The uncertainty caused by regulation increases with the potential for new carbon emission standards proposed under Section 111 of the Clean Air Act. The EPA's Clean Power Plan[15] standards would impact emissions from new and existing power plants. The proposed 111(d) rule would establish guidelines to reduce emissions, and states would subsequently need to design programs based on those guidelines to achieve the necessary reductions. While the specifics of the EPA's carbon proposal are subject to change when a final rule is issued, it is clear that any carbon emission limitations will negatively impact MISO's coal generation fleet. A recent assessment published by MISO shows that the proposed EPA rule could lead to an additional 14 GW of generation retiring over the next decade (2). Overall, 298 coal units in MISO are being impacted by environmental regulations, resulting in a projected 7 percent reduction in generation by 2016 (19). The potential reliability impacts due to the shift away from coal are startling. As planning reserves dissipate, the possible challenges to reliability increase exponentially. Exhibit 4 shows resource adequacy shortfalls projected by MISO over time.

> "Based on MISO's current awareness of projected retirements and the resource plans of its membership, Planning Reserve Margins will erode over the course of the next couple of years and will not meet the 14.2 percent requirement. The impacts of environmental regulations and economic factors contribute to a potential shortfall of 6,750 MW, or a 7.0 percent Anticipated Reserve Margin… by summer 2016. Accordingly, certain existing resources are projected to be reduced by 10,382 MW due to retirement and suspended operation."
>
> *—2013 Long-term Reliability Assessment, Page 54*

[14] Many utilities have received extensions until April 2016 to comply with MATS.
[15] On June 2, 2014, the U.S. Environmental Protection Agency, under President Obama's Climate Action Plan, proposed a plan to cut carbon pollution from power plants.

EXHIBIT 4. Projected Capacity Surplus/Shortfall, by Planning Year for MISO North/Central Region

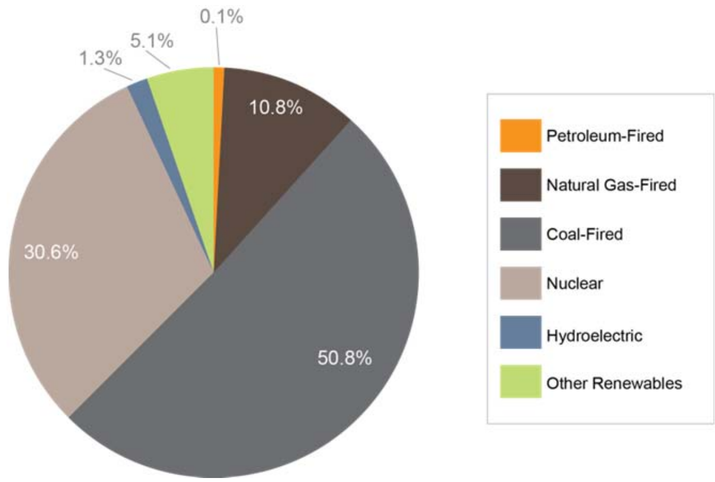


SOURCE: MISO, October 22, 2014, *Long Term Resource Adequacy Update.* Available www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/System%20Planning%20Committee/2014/2014102/20141022%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2004%20Long%20Term%20Resource%20Adequacy%20Assessment.pdf. (accessed 10/17/14)

EPA regulations are hitting states with high proportions of coal generation harder than other regions.[16] As shown in Exhibit 5, these regulations are going to have a significant impact on Michigan, where more than 50 percent of energy generation in 2013 came from coal power plants (20). Compounding the issue presented by EPA regulations is the age of Michigan's current coal generating fleet. Most of Michigan's coal plants came online in the 1960s and '70s, as illustrated in Exhibit 6. In fact, the average age of a coal generation facility in Michigan is 52 years old (21). In order to comply with new emissions targets, coal plants are faced with the decision to invest in costly retrofits or retire from operation. In many cases, aging small and midsized plants are unable to justify the investment needed to continue operation because the new equipment is expensive and results in lost generating capacity (22).

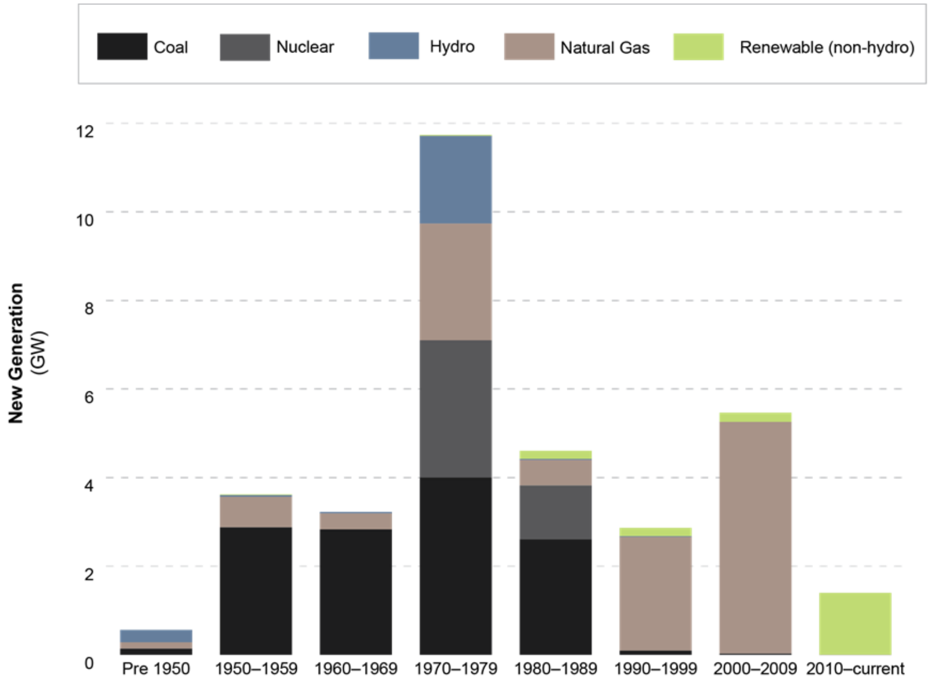
[16] PJM (RTO for Ohio River Valley and Mid-Atlantic States) and MISO are projected to have the largest amounts of coal plant retirements: 21 GW of coal capacity to retire in the next five years or so, compared to about 20 GW of capacity whose retirement has already been announced. (See Brattle Group, November 2013, *Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices.* Available at: www.brattle.com/system/news/pdfs/000/000/584/original/Coal_Plant_Retirements_-_Feedback_Effects_on_Wholesale_Electricity_Prices.pdf?1386628173, accessed 10/10/14)

EXHIBIT 5. Michigan's Current Electric Generation Fuel Mix



SOURCE: U.S. Energy Information Administration, June 2014, *State Profile and Energy Estimates.* Available at www.eia.gov/state/data.cfm?sid=MI. (accessed on 10/13/14)

EXHIBIT 6. New Electric Generation in Michigan by Fuel Source



SOURCE: Reported by MPSC Commissioner Sally Talberg, July 31, 2014, at the Michigan Energy Providers Conference during presentation entitled *Resource Adequacy: Not Just Keeping the Lights On.*

Impacts from Retirements in Michigan

MISO consists of nine local resource zones. These zones were designed to encourage the right amount of planning resources located in each zone, to meet reliability goals. The zone's boundaries account for the limitations that exist due to transmission constraints. Import and export limitations are defined for each zone through MISO. These limits establish the amount of resources each zone can rely on outside of its boundaries for its planning purposes.

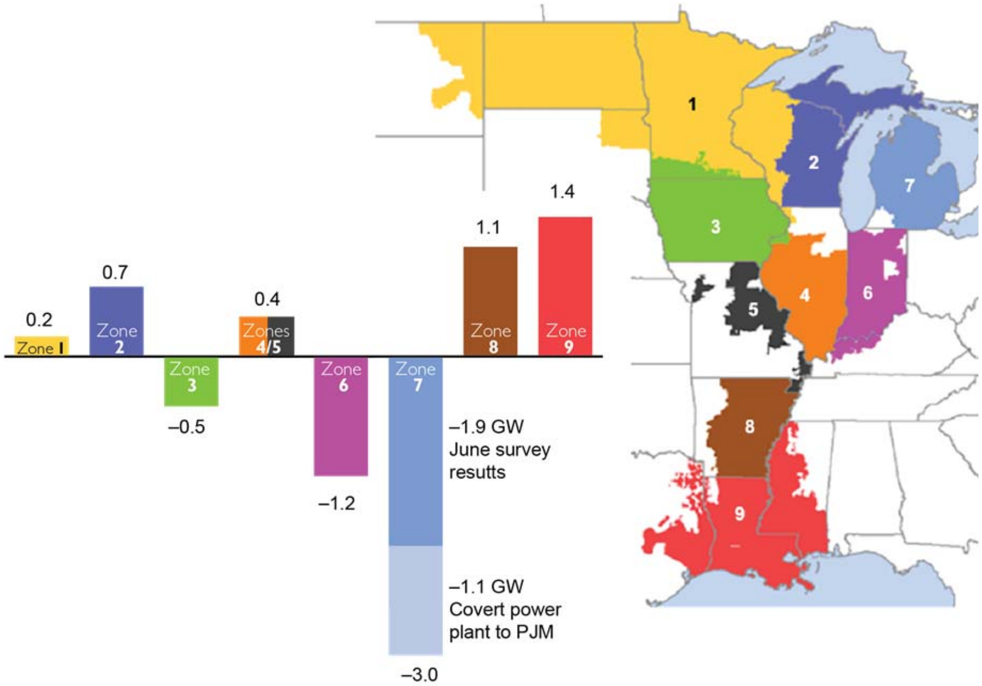
MISO conducts an annual study of the approximately 140 load serving entities[17] in its service territory to determine the ability of their system to meet its load demand requirements as well as the planned reserve margin (PRM).[18] These assessments are based on information provided by utilities and other plant owners about facilities being removed from service. When looking at resource adequacy for each zone, as shown in Exhibit 7, it is clear that the shortfall is driven in large part by Zone 7, the Lower Peninsula of Michigan. Beginning as soon as 2016, Michigan will be short nearly 3 GWs of generation necessary to maintaining adequate reserve margins (23). Both Consumers Energy and DTE Energy, which collectively provide more than 76 percent of the state's electricity have made recent announcements about plant retirements (24). In a February 2014 news release, Consumers Energy reported that its power plants being decommissioned had each operated more than 60 years and represent nearly 1 GW of generating capacity, which will only be partially offset by the purchase of a merchant generating plant[19] in Jackson, Michigan. DTE Energy expects to retire 0.2 GW of coal generation by April of 2016 and additional unannounced coal retirements anticipated between 2019 and 2025 (25). Other municipal power plants expect to retire an additional 0.16 GW by April 2016. In total the Lower Peninsula, will lose 1.3 GW of coal-fired generation (26). Sometimes merchant generators continue to operate but leave the MISO market. The 1.2 GW New Covert Generation Station, located in West Michigan, has entered into agreements for transmission upgrades to allow it to leave the MISO market and join the PJM market.

[17]A load serving entity secures energy and transmission service to serve the electrical demand and energy requirements of its end-use customers.

[18] This is called a Loss of Load Expectation (LOLE) study, which is a probabilistic analysis to set the Planning Reserve Margin Requirement for the load serving entities in the upcoming Planning Year (June 1 through May 31).

[19] Merchant generators are facilities not operated by a utility, but that participate in the wholesale electric market.

EXHIBIT 7. 2016 Resource Adequacy Forecast, Local Resource Zone Summary



SOURCE: MISO. October 22, 2014. *Long Term Resource Adequacy Update.* Available https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/System%20Planning%20Committee/2014/20141022/20141022%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2004%20Long%20Term%20Resource%20Adequacy%20Assessment.pdf. (accessed 10/17/14)

Regional Entities' Role in Resource Planning

RTOs play a role in planning for adequate resources but they do not have the authority to enforce planning requirements through construction of new generation. In most cases, the RTO administratively sets the demand for capacity based on expected load—with a sufficient reserve margin to achieve reliability standards—and allows market-based mechanisms to provide adequate resources.

Capacity Markets

Without the authority to determine where and when generation is built, RTOs have to rely on market prices to ensure investment in adequate resources. This has yet to be a concern for MISO because it has operated with more than 20 percent reserve margins, due to a surplus of capacity (2). Responding to diminishing reserve margins, some RTOs have employed "capacity markets" to attract the generation resources needed to meet their reliability standards. These markets emerged to supplement the price that power producers earn through energy markets. The price of electricity is based on variable operating costs, meaning that energy markets only compensate an electricity generator if they are actually generating power. Due to the high cost and long life of generation investments, "energy only" payments made it difficult for power generating plants to recover their total costs through the market. This is often referred to as the "missing money" problem—that is, the money necessary for the investment required for long term capacity needs is missing from the regional wholesale markets (27).

Capacity market structures vary among RTOs. MISO operates a voluntary capacity market designed to ensure each energy provider has adequate resources to meet the upcoming year's anticipated need. This creates a price signal to encourage building new energy generation and retaining existing energy generation within the RTO.

Capacity Markets Have Failed to Ensure Resource Adequacy

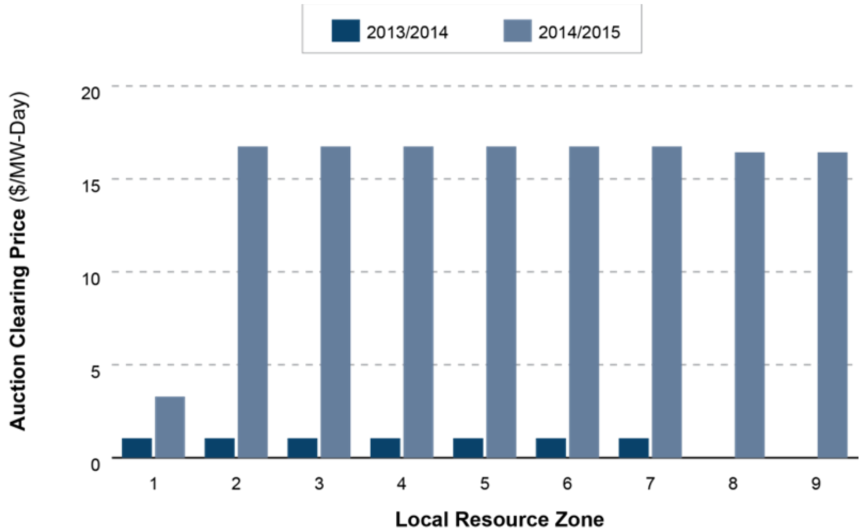
Regional transmission organizations are attempting to utilize capacity markets because, unlike state public service commissions, they have no direct authority to actually require or approve the building of new generation resources. MISO's Independent Market Monitor's (IMM)[20] annual report detailing performance and determining future planning goals found not only that MISO is expected to be capacity deficient in 2016, but also that its capacity market simply does not provide proper incentive to ensure the availability of adequate resources or encourage investment in new resources—primarily generation.

MISO's first year of administering its capacity auction resulted in very low capacity prices, due in part to overabundant supply. But as excess generation disappears over the next few years, capacity prices are expected to continue rising (28). As Exhibit 8 shows, prices have already increased in anticipation of capacity shortfalls throughout MISO.

> "This report shows that MISO's economic signals in 2013 would not support private investment in new resources, which is partly due to the modest capacity surplus that currently exists in MISO. However, we believe the economic signals would continue to be inadequate even under little or no surplus because of the shortcomings of MISO's current capacity market described in this report. This resource adequacy concern is likely to rise as environmental regulations, increasing wind output, and low natural gas prices accelerate the retirements of many coal-fired resources in the next two years."
>
> *—2013 State of the Market Report*

[20] The Independent Market Monitor is an impartial entity responsible for reviewing and reporting on RTO functions pursuant to FERC Order No. 179.

EXHIBIT 8. MISO Capacity Price—Auction Results



SOURCE: MISO 2013/2014 and 2014/2015 Auction Results. Available at www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2013-2014%20MISO%20Planning%20Resource%20Auction%20Results.pdf and www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2014-2015%20PRA%20Summary.pdf. (accessed 10/14/14)

Despite the use of mechanisms like capacity markets to incent new generation, MISO specifically recognizes states' obligation to ensure adequate resources.[21] This was recently emphasized by comment from a MISO representative to the Michigan Energy Providers Conference, a group that included state regulators and others when he noted that although he worried about resource adequacy, it was the responsibility of states and energy providers to "fix it."[22] The implication for Michigan as it decides how best to meet its future capacity needs is quite clear: relying upon the regional transmission organization to ensure the availability of adequate capacity is—at best—questionable.

Difficulties with Regional Coordination

By relying upon MISO and the regional wholesale market system for ensuring Michigan's future capacity needs, another challenge emerges—the difficulty that MISO and PJM currently have with trading available capacity resources. The selection of PJM by AEP Ohio and others created a trading roadblock in the Midwest. This effectively limited Michigan's ability to interact with Ohio power generators, who had traditionally been electricity trading partners.

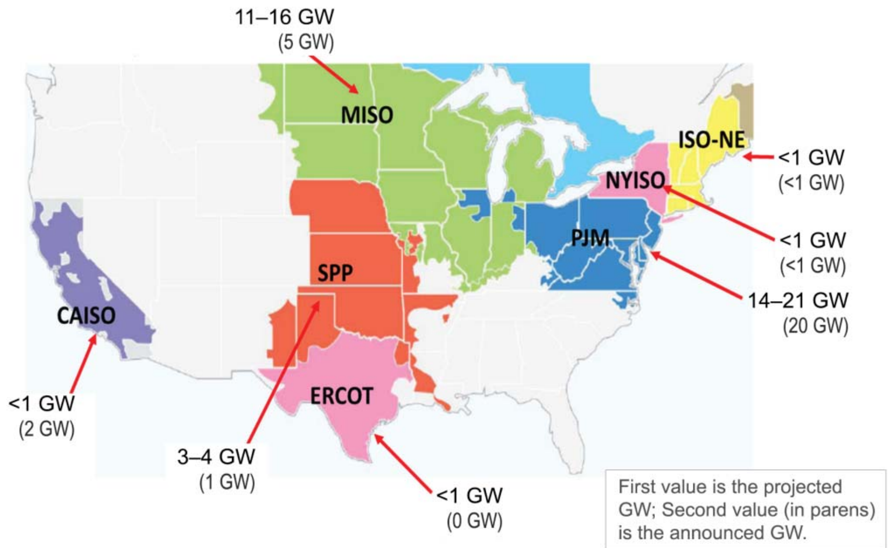
> "The second issue with MISO's current capacity market is the prevailing barriers to capacity trading between PJM and MISO. Capacity prices in both markets will only be efficient if participants can freely import and export capacity to arbitrage capacity price differences between markets to the extent that the physical transmission capability allows."
>
> *—2013 State of the Market Report, Page 38*

[21] The MISO Module- E Tariff on Resource Adequacy states, "Nothing in this (tariff) affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy." (Available at www.misoenergy.org/_layouts/MISO/ECM/Download.aspx?ID=152746, accessed on 10/14/14)

[22] Reported by MPSC Commissioner Sally Talberg on July 31, 2014, at the Michigan Energy Providers Conference during presentation entitled *Resource Adequacy: Not Just Keeping the Lights On.*

The FERC has ordered each RTO to develop mechanisms to address interregional coordination. While both MISO and PJM are currently working to address this problem, it has yet to be resolved. Even assuming excess resources in PJM—a generous assumption, given that the same factors accelerating the retirement of coal plants are impacting that area of the country as well as the Midwest and the MISO region (see Exhibit 9)—such an excess doesn't help Michigan meet its needs if those resources cannot be effectively and efficiently brought to the state.

EXHIBIT 9. RTO Coal Retirements Map



SOURCE: Brattle Group, November 2013, *Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices.* Available at www.brattle.com/system/news/pdfs/000/000/584/original/Coal_Plant_Retirements_-_Feedback_Effects_on_Wholesale_Electricity_Prices.pdf?1386628173. (accessed 10/10/14)

Attempts to Regain State Control

Retail market deregulation at the state level effectively forces a state to rely on the federally regulated regional transmission organizations for most of its capacity needs. As noted earlier in this report, MISO's current capacity market structure has failed to produce the necessary investment in new, long-term generation capacity. Some states that have fully deregulated their retail markets are also experiencing inadequate capacity market structures and pricing systems in their regional transmission organizations. As a result, some are reacting by attempting to reassert some state control over capacity decisions. For example, both New Jersey and Maryland—fully deregulated states that are operating in the PJM regional market—expressed dissatisfaction with the results of their dependence upon the RTO capacity market system, primarily because it has not created the generation they want and believe they need. Shortly after, new legislation and regulations were passed in both states in an attempt to incent and support this new in-state generation. As reported in the May 18, 2012, issue of the *Chicago Tribune*: "The states want the new generation to create construction jobs, spur economic growth, lower prices, allow for the retirement of older, dirtier plants and ensure a reliable supply of in-state generation" (29).

The initiatives in New Jersey and Maryland have caused great tension—and litigation—between the state and the federal governments. In both cases, FERC or PJM have successfully contested these state attempts to reassert control over capacity decisions (30).

Addressing Capacity Needs in Michigan

One of the issues that Michigan needs to address as it decides how best to address its capacity shortfall is how much control it wants to maintain over its own energy policy regarding the amount, mix, and cost of future generation, and how much it wants to relinquish to the federal government. The federal government already has the authority over some matters that clearly impact state energy policy, such as air emissions. This is not the case, however, when it comes to resource adequacy. Michigan has the responsibility to ensure that an adequate supply of electricity is available, the market and regulatory structure it adopts will significantly impact the extent of its control. While improvements have been made to the regulatory environment to support adding new generation, issues surrounding time and investment keep this from happening.

Complications Presented by Michigan's Market Structure

Michigan's unique hybrid retail market structure for electricity allows 10 percent of the electric load in the state to be served by retail energy marketers under retail open access. This market structure creates challenges for ensuring reliability and resource adequacy, since customers of these retail energy marketers—primarily large industrial and commercial customers[23]—can switch back and forth between the retail market and the regulated utility that services their area. Without customer base certainty, utilities are not going to make long-term investments in new generation.

In addition, Michigan's market structure also results in higher operating costs for regulated utilities. Under Michigan's energy choice law, retail energy marketers are not regulated and do not have an obligation to serve customers, but incumbent utilities do. If a customer chooses to leave a retail energy marketer, the MPSC requires that regulated utilities accept the customer back under "return-to-service rules." This ability to switch between a regulated utility and a retail energy marketer, combined with the state requirement that its utilities serve as "default service providers," means that regulated utilities must be prepared to serve a customer base with an unknown number of actual customers on a year-to-year basis. If a customer chooses to return to a utility, there must be adequate capacity to provide service. Retail energy marketers provide 2.4 GWs of electricity under the 10 percent cap; this load could potentially return to utility service providers with limited notice (32, p. 19). Utilities either have to maintain this excess capacity, or purchase electric power at market prices to cover the needs of customers that may or may not return. This spreads the costs of excess generating capacity across their remaining customers. Either way, regulated utilities are required to operate at a higher cost that is not passed on to the returning customer, thus disrupting the ability of the market to send signals through prices. Before Michigan placed a cap on retail open access in 2008, nearly 4 GWs shifted between utility service and retail energy marketers as wholesale prices fluctuated.[24] The inability to determine which customers might return, when they may do so, and what their electricity needs will be creates uncertainty. This uncertainty seriously compromises the ability of utilities to accurately plan for the future energy needs of the state.

[23] Commercial and industrial customers accounted for all of the participation in the electric choice programs during 2013.
[24] Four GWs is the equivalent to approximately six large power plants. (See *Readying Michigan to Make Good Energy Decisions,* www.michigan.gov/documents/energy/electricc_report_440539_7.pdf, accessed 10/10/14)

Issue in Focus:

Michigan's Upper Peninsula

Across the state, the problems created by Michigan's current market structure are clear—the uncertainty in planning for future reliability needs, the involvement of federal agencies, the tension between federal and state regulators, and the shifting of fixed costs to remaining residential and small business customers. Nowhere is it being demonstrated more clearly, however, than in Michigan's Upper Peninsula.

In 2008, the Michigan Legislature reduced the level of retail open access participation from 100 percent to 10 percent of an electric utility's average retail sales. One industry was specifically exempt from the 10 percent cap, though: iron ore mining and processing facilities. These facilities were allowed to receive service from an alternate supplier regardless of whether their load exceeded that 10 percent cap. In June 2013, Cliffs Natural Resources, which operates two mines in the Upper Peninsula, notified Wisconsin-based We Energies that it would be leaving their service for an alternative electric supplier (33). Following that loss of more than 80 percent of their customer base, We Energies announced their plans to retire the 431 MW Presque Isle Power Plant (PIPP) in Marquette, Michigan.

Closing the Presque Isle Power Plant, however, would threaten reliability across the Upper Peninsula. Both the state and federal government are attempting to control the situation, by insisting that PIPP remain in service despite the economic implications. We Energies entered into an agreement to keep the plant open with the Midcontinent Independent System Operator (MISO)—the federally regulated entity in charge of ensuring reliability for the regional electric grid. This agreement would require Upper Peninsula customers to pay $97 million per year to maintain PIPP (34). The Michigan Public Service Commission (MPSC) is contesting this decision and attempting to reassert control over the situation in the Upper Peninsula. The MPSC claims MISO's intervention was unjustified because PIPP cannot retire without the MPSC's permission (35). The MPSC continues to work with various parties to seek other solutions to the Upper Peninsula's long-term energy needs (36).

> "[The Presque Isle crisis] is an example of what happens when the federal government makes [energy] decisions for you."
>
> —Valerie Brader, *Senior Policy Advisor to Governor Rick Snyder*

> "If the MPSC were to spread the costs of the loss in load in [We Energies] territory (85% load loss)… to Michigan full-service customers, the increase in rates could be greater than 70%."
>
> —*Readying Michigan to Make Good Energy Decisions: Electric Choice* pg. 13.

The planned retirement of PIPP exposes another major challenge created by Michigan's "hybrid" energy market: utilities in Michigan are required to have the capacity to serve all customers in their service territory, even those who choose a different supplier. Despite no longer selling power directly to the mines, We Energies must maintain PIPP in order to serve them if they decide at any time to return to regulated service. The obligation to serve forces utilities to operate with higher costs that are not paid by customers served by alternative energy suppliers. Instead, the added costs are passed on to the utility's existing customers.

Because of Michigan's hybrid market structure, residents and businesses in the state's Upper Peninsula are absorbing the costs to maintain an outdated plant. These significant price hikes, along with the problems of state and federal tension and planning for future reliability needs, are evidence enough that the state needs to take concrete steps to address its energy challenges as soon as possible.

Determining the Right Resource Mix

Different resources to meet Michigan's future capacity needs include new generating plants, long-term contracts with independent power producers, short-term market purchases, renewable energy resources (such as wind), energy efficiency programs, transmission improvements, and demand-side options, as well as emerging technologies such as distributed generation. Several factors will impact the role of each of these resources, including federal environmental regulations (both existing and proposed); state resource portfolio standards; projections for demand; fuel prices; prices for various construction materials and different kinds of generating equipment, such as wind turbines, gas turbines, and their components; and resulting electric rates for customers, both residential and business.

Natural gas is currently the fuel of choice, primarily because it is a relatively clean, inexpensive, and abundant fuel source. Although natural gas prices are historically volatile, Michigan does have abundant storage capacity to potentially soften price increases, at least in the short term. Wind energy will certainly continue to play a role in the overall generation portfolio, but its intermittent nature limits its responsiveness. As a result, only 13 percent of the installed capacity of a wind turbine can be counted toward meeting the electric load plus PRM requirement.

Conclusion

Ensuring adequate electricity supply has emerged recently as one of the most critical issues facing Michigan. The abundant supplies of the past few years—magnified by declining demand due to the economic slowdown of the Great Recession—are rapidly coming to a close as aging coal plants retire in the face of federal environmental regulations. Although changes to the regulatory structure at both the national and state level will impact this issue, the fact remains: the state maintains the responsibility to ensure resource adequacy and address the looming capacity challenges Michigan faces. A number of decisions must be made about the right mix of the available resources and how much to depend on energy efficiency, renewable energy, more generating facilities, and other ways to address the capacity shortfall. The complications presented by Michigan's current market structure must also be addressed, and the state needs to recognize the lack of success that the federally regulated regional transmission organizations have thus far had in supporting new capacity investments. Finally, the state needs to decide how much to relinquish to the federal government by depending on the regional transmission organization and how much control to maintain over its energy future.

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November 2014

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Initial Reliability Review
November 2014

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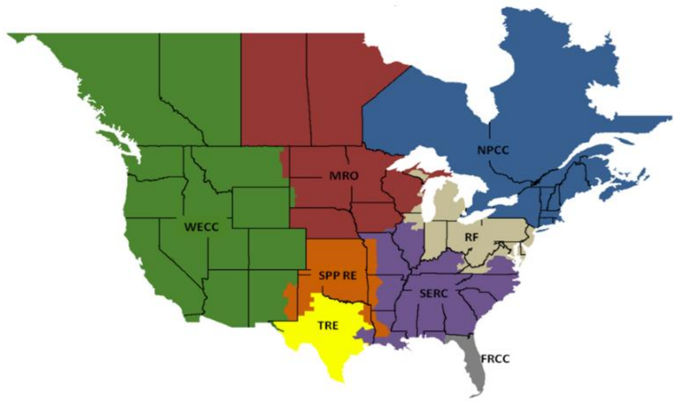
Preface

The North American Electric Reliability Corporation (NERC) has prepared the following assessment in accordance with the Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and adequacy of the bulk power system (BPS) in North America.[1] NERC operates under similar obligations in many Canadian provinces, as well as a portion of Baja California Norte, Mexico.

NERC is an international regulatory authority established to evaluate and improve the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term (10-year) reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[2]

NERC Regions and Assessment Areas



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP-RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

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[1] H.R. 6 as approved by of the One Hundred Ninth Congress of the United States, the Energy Policy Act of 2005. The NERC Rules of Procedure, Section 800, further detail the Objectives, Scope, Data and Information requirements, and Reliability Assessment Process requiring annual seasonal and long-term reliability assessments.

[2] As of June 18, 2007, FERC granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS and made compliance with those standards mandatory and enforceable. Equivalent relationships have been sought and for the most part realized in Canada and Mexico. Prior to adoption of §215 in the United States, the provinces of Ontario (2002) and New Brunswick (2004) adopted all Reliability Standards that were approved by the NERC Board as mandatory and enforceable within their respective jurisdictions through market rules. Reliability legislation is in place or NERC has memoranda of understanding with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, Manitoba, Saskatchewan, British Columbia, and Alberta, and with the National Energy Board of Canada (NEB). NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. Manitoba has adopted legislation, and standards are mandatory there. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain Reliability Standards have been approved in that jurisdiction; others are pending. NERC standards are now mandatory in British Columbia and Nova Scotia. NERC and the Northeast Power Coordinating Council (NPCC) have been recognized as standards-setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for Reliability Standards to become mandatory. NEB has made Reliability Standards mandatory for international power lines. In Mexico, the Comisión Federal de Electricidad (CFE) has signed WECC's reliability management system agreement, which only applies to Baja California Norte.

Executive Summary

The Environmental Protection Agency (EPA), on June 2, 2014, issued its proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, commonly referred to as the proposed Clean Power Plan (CPP), under Section 111(d) of the Clean Air Act, which introduces CO_2 emission limits for existing electric generation facilities. On August 14, 2014, the NERC Board of Trustees directed NERC to develop a series of special reliability assessments to examine the proposed CPP. This report is NERC's initial reliability review of the potential risks to reliability, based on the assumptions contained in the proposed CPP.

NERC maintains a reliability-centered focus on the potential implications of environmental regulations and other shifts in policies that can impact the reliability of the bulk power system (BPS). Reliability assessments conducted while the EPA is finalizing the CPP can inform regulators, state officials, public utility commissioners, utilities, and other impacted stakeholders of potential resource adequacy concerns, impacts to system characteristics (such as essential reliability services (ERSs)), and, to some degree, areas that are more likely to require power-flow-related transmission enhancements to comply with NERC Reliability Standards. The goals of this review are listed in more detail below:

- Provide an evaluation and comparison of the assumptions supporting the CO_2 reduction objectives in the proposed CPP against other reported projections available within NERC assessment reports.
- Provide insight into planned generation retirements, load growth, renewable resource development, and energy efficiency measures that might impact CO_2 emissions and the EPA's target-driven assumptions.
- Provide insight into the potential reliability consequences of either the target-driven emission assumptions or the NERC projection-based assumptions and, in particular, the potential reliability implications if the EPA assumptions cannot be realized.
- Identify potential reliability impacts resulting from the expected resource mix changes, such as coal resource displacement or retirements, the impacts on regional planning reserve margins, the shifts in resource mix and ERS characteristics, the increase in variable resources, the concentration of resources by fuel source (especially natural gas), transmission and large power transfers, and other reliability characteristics, including regional differences.
- Support the electric power industry and NERC stakeholders by providing an independent assessment of reliability while serving as a platform to inform policy discussions on BPS reliability and emerging issues.

This report and its findings are *not* intended to: (1) advocate a policy position in regard to the environmental objectives of the proposed CPP; (2) promote any specific compliance approach; (3) advocate any policy position for a utility, generation facility owner, or other organization to adopt as part of compliance, reliability, or planning responsibilities; (4) support the policy goals of any particular stakeholder or interests of any particular organization; or (5) represent a final and conclusive reliability assessment.

The objective of this review is to identify the reliability implications and potential consequences from the implementation of the proposed CPP and its underlying assumptions. The preliminary review of the proposed rule, assumptions, and transition identified that detailed and thorough analysis will be required to demonstrate that the proposed rule and assumptions are feasible and can be resolved consistent with the requirements of BPS reliability. This assessment provides the foundation for the range of reliability analyses and evaluations that are required by the ERO, RTOs, utilities, and federal and state policy makers to understand the extent of the potential impact. Together, industry stakeholders and regulators will need to develop an approach that accommodates the time required for infrastructure deployments, market enhancements, and reliability needs if the environmental objectives of the proposed rule are to be achieved.

Herein, NERC examines the assumptions made in the EPA's four Building Blocks:[3]

Building Block 1: Heat rate improvements
Building Block 2: Dispatch changes among affected electric generating units (EGUs)
Building Block 3: Using an expanded amount of less-carbon-intensive generating capacity

[3] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.

Building Block 4: Demand-side energy efficiency

NERC identified the following factors as requiring additional reliability consideration:

Implementation of the CPP reduces fossil-fired generation: The proposed CPP aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030. Under the EPA proposal, substantial CO_2 reductions are required under the State Implementation Plans (SIPs) as early as 2020. According to the EPA's *Regulatory Impact Assessment*, generation capacity would be reduced by between 108 and 134 GW by 2020 (depending on state or regional implementations of Option 1 or 2).[4] 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.

Assumed heat rate improvements for existing generation may be difficult to achieve: NERC is concerned that the assumed improvements may not be realized across the entire generation fleet since many plant efficiencies have already been realized and economic heat rate improvements have been achieved. Multiple incentives are in place to operate units at peak efficiency, and periodic turbine overhauls are already a best practice. Site-specific engineering analyses would be required to determine any remaining opportunities for economic heat rate improvement measures.

Greater reliance on variable resources and gas-fired generation is expected: The CPP will accelerate the ongoing shift toward greater use of natural-gas-fired generation and variable energy resources (VERs) (renewable generation). 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). Increased natural gas use will require pipeline expansion to maintain a reliable source of fuel, particularly during the peak winter heating season. Pipeline constraints and growing gas and electric interdependency challenges impede the electric industry's ability to obtain needed natural gas services, especially during high-use horizons.

Rapid expansion of energy efficiency displaces electricity demand growth through 2030: In its rate calculation for best practices by state, the EPA assumes up to a 1.5 percent annual retail goal for incremental growth in efficiency savings. The EPA assumes that the states and industry would rapidly expand energy efficiency savings programs from 22 TWh/year in 2012, to 108 TWh/year in 2020, and reach 380 TWh/year by 2029. With such aggressive energy efficiency expansion, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking after 2020. The implications of this assumption are complex. If the EPA-assumed energy efficiency growth rates cannot be attained, additional carbon reduction measures would be required, primarily through reduced fossil-fired generation.

Essential Reliability Services may be strained by the proposed CPP: The anticipated changes in the resource mix and new dispatching protocols will require comprehensive reliability assessments to identify changes in power flows and ERSs. ERSs are the key services and characteristics that comprise the following basic reliability services needed to maintain BPS reliability: (1) load and resource balance; (2) voltage support; and (3) frequency support. New reliability challenges may arise with the integration of generation resources that have different ERS characteristics than the units that are projected to retire. The changing resource mix introduces changes to operations and expected behaviors of the system; therefore, more transmission and new operating procedures may be needed to maintain reliability.

More time for CPP 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. While

[4] Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data.

the EPA provides flexibility for meeting compliance requirements within the proposed time frame, there appears to be less flexibility in providing reliability assurance beyond the compliance period.

A summary of NERC's initial reliability review recommendations is provided below:

General Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP** and provide independent evaluations to stakeholders and policy makers.
2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern** and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.
3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach** that addresses BPS reliability concerns and infrastructure deployments.

Recommendations to Address Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins
The Regions, ISO/RTOs, and states should perform further analyses to examine potential resource adequacy concerns.

Transmission Planning and Timing Constraints
The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts to reliability from the proposed CPP. The EPA and policy makers should recognize the complexity of the reliability challenges posed by the rule and ensure the rule provides sufficient time for the industry to take the steps needed to significantly change the country's resource mix and operations without negatively affecting BPS reliability.

Regional Reliability Assessment of the Proposed CPP
Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, taking into consideration the time required to plan and build transmission infrastructure.

Reliability Assurance
The EPA, FERC, the DOE, and state utility regulators should employ the array of tools and their regulatory authority to develop a reliability assurance mechanism, such as a "reliability back-stop." These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.

Recommendations to Address Impacts Resulting from the Changing Resource Mix

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power
Further coordinated planning between the electric and gas sectors will be needed to ensure a strong and integrated system of fuel delivery and generation adequacy. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation, especially during extreme weather events (e.g., polar vortex).

The Changing Resource Mix and Maintaining Essential Reliability Services
ISO/RTOs, utilities, and Regions (with NERC oversight) should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.

NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.

The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support the additional variability and uncertainty on the BPS.

Increased Penetration of Distributed Energy Resources (DERs)
ISO/RTOs and system planners and operators should consider the increasing penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.

Plan for NERC Reliability Assessments

After the proposed CPP is finalized, specific transmission and resource adequacy assessments—including resulting reliability impacts—will be essential for supporting the development of SIPs that are aligned with system reliability needs. NERC's plan for reviewing and assessing the reliability impacts of the EPA proposal is included in Figure 1. This review includes a preliminary review of the assumptions and potential reliability impacts resulting from the implementation of the EPA's proposed CPP. As the EPA is scheduled to finalize its rule by June 2015, NERC will develop a specific reliability assessment in early 2015 that will focus on evaluating generation and transmission adequacy and reliability impacts. After the EPA rule is finalized, the states, either individually or in multi-state groups, are required to develop their SIPs by 2016 and 2018, respectively. NERC plans to provide a more specific and comprehensive reliability assessment before SIPs are submitted to the EPA. Additionally, a Phase III approach is tentatively planned for December 2016, which will examine finalized SIPs.

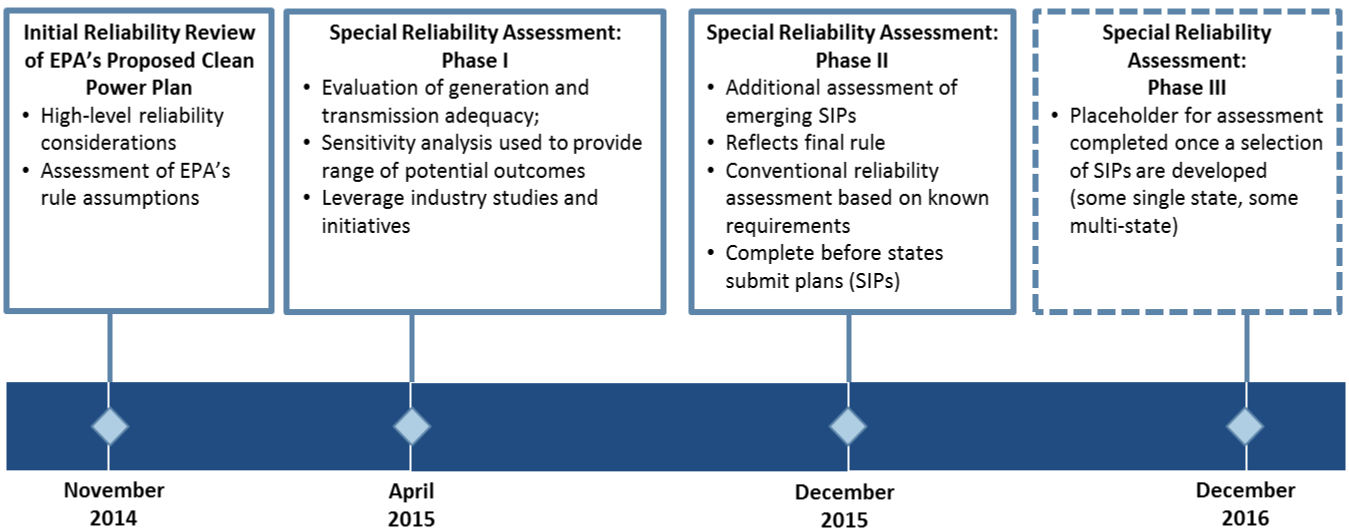

Figure 1. NERC's Assessment Actions and Schedule Timeline

Summary of the Proposed Clean Power Plan

The proposed CPP aims to cut CO_2 emission from existing power plants to 30 percent below 2005 levels by 2030. Substantial CO_2 reductions are required under State Implementation Plans. Under the EPA proposal, CO_2 reductions are required as early as 2020. According to the EPA's reliability assessment included in the proposed rule, these existing generation rules would result in between 108 and 134 GW of generation retirements by 2020 (depending on state or regional implementations of Option 1 or 2).[5]

The CPP proposal would apply to fossil-fired generating units that meet four combined qualification criteria: (1) units that commenced construction prior to January 8, 2014;[6] (2) units with design heat input of more than 250 MMBtu/hour (approximately a 25 MW unit); (3) units that supply over one-third of their potential output to the power grid; and (4) units that supply more than 219,000 MWh/year on a three-year rolling average to the power grid.[7] Given these criteria, the EPA estimates that approximately 3,000 U.S. fossil-fired electric generation units representing over 700,000 MW of existing nameplate generating capacity will be subject to the rule limitations.[8] NERC estimates that this magnitude represents approximately 65 percent of the total existing nameplate capacity in the United States.

The EPA-proposed draft regulations would, for the first time, limit CO_2 from existing power plants, thus addressing risks to health and the economy posed by climate change. These proposed regulations are intended to provide implementation flexibility and maintain an affordable, reliable energy system while cutting CO_2 and protecting public health and the environment.[9]

The EPA regulations propose implementation through a state-federal partnership under which states identify plans to meet the emission reduction goals. The EPA provides guidelines for states to develop implementation plans to meet state-specific CO_2 reduction goals and provides states the flexibility to design requirements suited to their unique situations. These plans may include generation mix changes using diverse fuels, energy efficiency, and demand-side management, and they allow states to work individually or to develop multi-state plans. The primary driver for realizing the EPA's 111(d) objectives is that SIPs need to produce significant CO_2 reductions starting as early as 2020.

As currently proposed, states have a flexible timeline for submitting plans to the EPA. Within one year of finalizing the rule—expected in June 2015—state environmental agencies must submit implementation plans to the EPA for approval. Submitted state-specific plans, due in June 2016, must outline requirements and enforceable limitations for affected generating units to meet the rule's average CO_2 emission rate goal for each state within two compliance periods: (1) an initial 10-year average interim emission rate limit for the period 2020–2029, and (2) a final annual emission rate limit starting in 2030.

The EPA provides states with an option to convert CO_2 emission rate limitation into an annual mass-based limitation. It is likely that most states will pursue this option due to the challenges state permitting agencies have in developing unit-specific emission rate limitations. The simpler mass-based CO_2 emission cap program also negates the need for state legislative action to authorize agencies to limit plant output and enact an enforceable program for compliance with average emission rates. The EPA's proposed Clean Power Plan timeline is outlined in Figure 2.

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[5] State implementation of Option 1 assumes 134 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020. For additional information, see: Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants (June 2014) and supporting IPM Model documentation and data. Regional implementation of Option 2 assumes 108 GW of retirements (includes CC, Coal, CT, Nuclear, O/G, and IGCC) by 2020.

[6] All sources starting construction after January 8, 2014, would be subject to new source performance standards and exempt from the EPA Clean Power Plan requirements.

[7] 79 FR 34854 https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating page 34854.

[8] EPA CPP TSD – 2012 Unit-Level Data Using EGrid – Methodology, June 2014. Generation, Emissions, Capacity data used in EPA's State Goal Computation TSD.

[9] EPA Fact Sheet: Clean Power Plan – Why we Need A Cleaner, More Efficient Power Sector "*The proposed Clean Power Plan will cut hundreds of millions of tons of carbon pollution and hundreds of thousands of tons of harmful particle pollution, sulfur dioxide and nitrogen oxides. Together these reductions will provide important health protections to the most vulnerable, such as children and older Americans*." http://www2.epa.gov/sites/production/files/2014-05/documents/20140602fs-benefits.pdf.

Summary of the Proposed Clean Power Plan

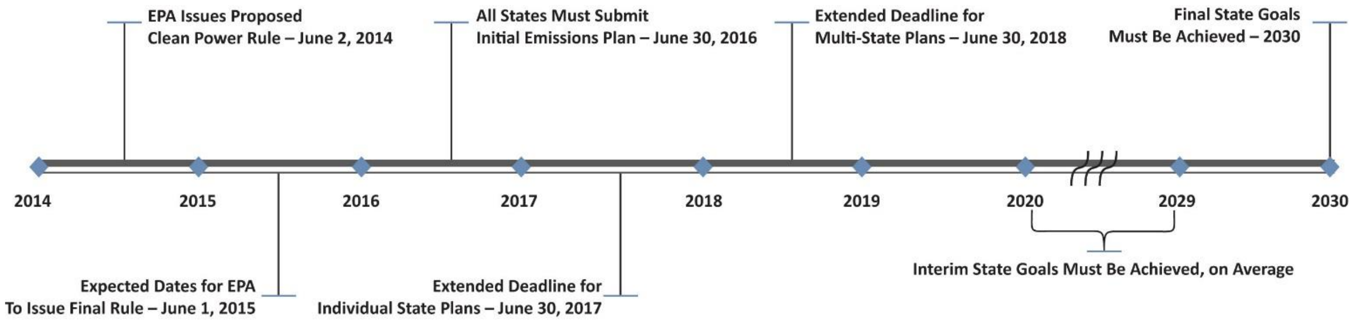

Figure 2. EPA Proposed Clean Power Plan Timeline

The EPA would have one year to review and approve implementation plans for each state by June 2017. Under this schedule, impacted generating units would have two and a half years to develop respective compliance strategies and potentially permit, finance, and build needed replacement capacity and transmission. In its current form, this implementation schedule would be a challenge for states to implement and for affected sources to comply with, especially given the expected legal challenges to both the EPA and state rules. In recognition of these challenges, the EPA would provide states with a one-year extension to June 2017 to submit a SIP if justification is provided, and a two-year extension (June 2018) for states that elect to develop multi-state (regional) programs (e.g., Regional Greenhouse Gas Initiative (RGGI)). While the EPA extensions apply to state plan submissions, the January 1, 2020, program start date for affected sources would not be extended under the proposed CPP. Therefore, the impacted fossil-fired units may be left with as little as six months to develop and implement compliance plans. Considering the number and variety of outcomes for each of the proposed scenarios, the states and industry should initiate planning immediately upon finalization of the CPP.

The proposed Clean Power Plan, which is based on EPA analysis of historical data about emissions and the power sector, is intended to create a consistent national formula for reductions that reflects their Building Block assumptions. The formula applies the four Building Blocks to each state's specific information, yielding a carbon intensity rate for each state.[10] There is a wide range of potential proposals, including individual state and multi-state groupings, each with different implementation schedules. The range of potential submitted SIPs and changes to the proposed timeline create significant uncertainties for industry and resource planners.

EPA's Proposed Clean Power Plan: Options

The EPA is proposing a Best System of Emission Reduction (BSER) goal, referred to as Option 1, and is taking comment on a second approach, referred to as Option 2.

Option 1: Involves higher deployment of emission reduction but allows a longer time frame (2030).

Option 2: Has a lower deployment of emission reductions over a shorter time frame (2025) by each state. Proposed guidelines allow states to collaborate and demonstrate emission performance on a multi-state basis, in recognition that electricity is transmitted across state lines.

Clean Power Plan Building Blocks

According to the proposed plan, this can be achieved through the development of state-specific emission rates to limit CO_2 by applying four different BSER Building Blocks.[11] Each Building Block represents a different approach for achieving the proposed targets. According to the EPA, the proposed plan considers impacts to system reliability and electricity prices. The BSER is not intended to impact resource planning and does not dictate retirements, additions, or operating practices for individual units. Instead, it would provide state emission rate limits that would shape the future resource mix through state and market processes in subsequent years as SIPs and multi-state plans are developed and implemented.

[10] EPA Fact Sheet: Clean Power Plan - National Framework for States.

[11] EPA Clean Air Act: Section 111(d) authorizes EPA to apply "best system of emission reduction" to this section's affected sources.

The EPA's Proposed Clean Power Plan: Four Building Blocks

Plant Efficiency

Make fossil fuel power plants more efficient by implementing a 6 percent (on average) unit heat rate improvement for all affected coal-fired units. The EPA suggests that some plants could further improve process efficiency by 4 percent through the adoption of best operational practices, and an additional 2 percent through capital upgrade investments.

Natural Gas

Use low-emitting power sources more by redispatching existing natural gas combined-cycle (NGCC) units before the coal and older oil-gas steam units. EPA draft rate limitations include CO_2 reduction assumptions from the ongoing increases in the use of NGCC capacity (with up to a 70 percent capacity factor). This additional NGCC capacity (440 TWh/year) displaces coal (376 TWh/year) and oil-gas steam generation (64 TWh/year) by 2020, compared to 2012 levels.

Renewable Energy

Use more zero- and low-emitting power sources through building capacity by adding both non-hydro renewable generation and five planned nuclear units. EPA calculations assume qualifying non-hydro renewable generation can grow rapidly from 218 TWh/year in 2012, to 281 TWh/year by 2020, to reach 523 TWh/year by 2030.

Energy Efficiency

Use electricity more efficiently by significantly expanding state-driven energy efficiency programs to improve annual electricity savings by up to 1.5 percent of retail sales per year. The calculation assumes the states and industry can rapidly expand energy efficiency programs to increase savings from 22 TWh/year in 2012, to 108 TWh/year in 2020, and to 380 TWh/year by 2029. Ultimately, EPA energy efficiency assumptions suggest that electric power savings will outpace electricity demand growth, resulting in negative electricity usage from 2020 through 2030.

Clean Power Plan – Assumption Review

This section provides a critical review of the EPA's assumptions for state-specific CO_2 emission rates and presents possible reliability challenges that need to be considered.

Building Block 1 – Coal Unit Heat Rate Improvement

Plant Efficiency

The EPA's heat rate assessment analyzed gross data for 884 coal-fired electric generating units (EGUs) during a 10-year period.[12] The regression analysis examined the effects of the capacity factor and the ambient temperature on the gross heat rate efficiencies of coal-fired EGUs. The EPA's assessment concluded that in-state coal units can achieve up to a 4 percent rate of improvement through the use of best operational practices. An additional 2 percent of efficiency improvements would be achieved through capital upgrade investments.

Review of EPA Assumptions and Potential Reliability Impacts

The EPA calculated unit-specific heat rates using gross generation data from the Continuous Emission Monitoring Systems (CEMSs). With this approach, the EPA excluded generation-reducing effects from post-combustion environmental controls, such as selective catalytic reduction and flue-gas desulfurization controls. The EPA then used net generation data, without consideration for these retrofits, for coal-fired EGUs when calculating the state CO_2 emission rate goals. These retrofits will reduce the net output of these units, as well as their associated net heat rate efficiency. Not considering these reductions creates an inconsistent approach, especially considering that most coal-fired EGUs will require control retrofits to comply with environmental regulations, such as the Mercury Air Toxic Standards (MATS) and Section 316(b) of the Clean Water Act.

The EPA's regression analysis does not adjust for the following factors that have profound effects on the process efficiency of a coal-fired EGU:[13] (1) subcritical versus supercritical boiler designs; (2) fluidized bed combustion, integrated gasification combined-cycle (IGCC), and pulverized coal; (3) unit size and age; and (4) coal quality variations in moisture and ash (i.e., every 5 percent change in coal moisture results in a 1 percent change in boiler heat rate efficiency).

Impacts on Coal-Fired Unit Efficiency Rates

Lower-capacity factors will cause an increase in heat rates, particularly if the lower-capacity factors are due to the cycling of the coal units. As a result of Building Block 2, coal units will cycle more often; therefore, assumed heat rate improvements across the entire coal fleet are unlikely. While recognizing capacity effects in the regression analysis, the EPA did not evaluate the effects of lower-capacity factors resulting from the dispatching of natural gas generation before coal generation.

Periodic Turbine Overhauls

Turbine overhauls are referenced as a major heat rate improvement method in an EPA Clean Power Plan technical support document.[14] Regular turbine overhauls are generally not practical or economical, because these procedures require the unit to be out of service for an extended period of time. As well, the power industry already has multiple incentives to operate units at peak efficiency (i.e., profit maximization and competitive advantage).

Overall, improving the existing U.S. coal fleet's average heat rate by 6 percent may be difficult to achieve. Possible options and considerations for attaining a portion of this target may include the following:

- Site-specific engineering analyses are required to determine if there are remaining opportunities for heat rate improvement measures through implementation of operational best practices or capital investments.
- If the U.S. coal fleet does not achieve target heat rates, more CO_2 reductions would be required from other CPP Building Block measures.
- This can result in some coal-fired power plants retiring earlier than anticipated, which creates additional uncertainty in future generation resources.

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[12] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 2-18.
[13] These differences are illustrated in Figure 2-2 of *GHG Abatement Measures* (EPA June 2014).
[14] Coal-Fired Power Plant Heat Rate Reductions (January 2009).

Building Block 2 – Gas Unit Re-Dispatching

Natural Gas

The EPA assumes that reductions in CO_2 emissions from existing power plants can be achieved by dispatching existing NGCC units ahead of coal units. In particular, the EPA assumes existing NGCC units can achieve a 70 percent utilization rate with avoided incremental costs of less than $33/metric ton CO_2.[15] In its state-specific goal computation, the EPA calculated that 440 TWh/year of additional NGCC generation could potentially displace 376 TWh/year of coal and 64 TWh/year of oil-gas steam units of 2012 generation.[16]

Review of EPA Assumptions and Potential Reliability Impacts

Upon reviewing the EPA's Building Block 2 assumptions, NERC found a number of reliability concerns regarding increased reliance on natural-gas-fired generation that should be evaluated.

Historically, the primary function of the NGCC unit is to follow the load of energy throughout the day (i.e., the intermediate, or midrange, part of the load duration curve). While some NGCC units are capable of operating at a high capacity factor, the vast majority of this type of generation is used for load following. Due to lower gas prices, NGCC units are currently being dispatched as a baseload resource, displacing baseload coal-fired EGUs. Unlike baseload coal-fired generation, NGCC units are better suited to follow load. As mentioned earlier, cycling coal-fired EGUs reduces heat rate efficiencies, causing their CO_2 emission rates (lbs/MWh) to deteriorate, and further offsetting the Building Block 1 assumptions.

Generally, the power industry relies upon diversification of fuel sources as a mechanism to offset unforeseen events (e.g., abnormal weather, regional transfers, labor strikes, unplanned outages); ensure reliability; and minimize cost impacts. Fuel diversification is also a component of an "all-hazards" approach to system planning, which inherently provides resilience to the BPS. The EPA estimates that an additional 49 GW of nameplate coal capacity will retire by 2020 due to the impacts of the proposed CPP.[17] When including the 54 GW of nameplate coal capacity already announced to retire by 2020[18] (mostly due to MATS), the power industry will need to replace a total of 103 GW of retired coal resources by 2020, largely anticipated to be natural-gas-fired NGCC and CTs. Considering the current and ongoing shift in the resource mix, the EPA proposes to further accelerate the shift, lessening the industry's diversification of fuel sources.

As observed during the 2014 polar vortex,[19] the relationship between gas-fired generation availability and low temperatures challenges the industry's ability to manage extreme weather conditions—particularly when conditions affect a wide area and less support is available from the interconnection. The polar vortex served as an example of how extended periods of cold temperatures had direct impacts on fuel availability, especially for natural-gas-fired capacity. Higher-than-expected forced outages were observed during the polar vortex, particularly for natural-gas-fired generators, as a result of fuel delivery issues and low temperatures. Overall, extreme weather conditions have the potential to strain BPS reliability and expose risks related to natural-gas-fired generation availability (Figure 3). With greater reliance on natural-gas-fired generation, the resiliency and fuel diversification that is currently built into the system may be degraded, which NERC has highlighted in recent gas-electric interdependency assessments.

[15] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 3-26.

[16] Clean Power Plan Proposed Rule: Goal Computation – Technical Support Document http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-goal-computation.

[17] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014 pg. 3-32).

[18] Energy Ventures Analysis maintains a complete list of announced power plant retirements in the contiguous United States, retirements as of 10/02/2014.

[19] NERC 2014 Polar Vortex Review:
http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

Fuel Supply and Delivery	Extended Low Temperatures
• Natural gas interruptions • supply injection • compressor outages • one pipeline explosion • Oil delivery problems • Inability to procure gas • Fuel oil gelling	• Low temperature limits for wind turbines • Icing on hydro units • Failed auxiliary equipment • Stress of extended run times • Frozen instrumentation (drum level sensors, control valves, and flow and pressure sensors)

Figure 3. Causes for Generator Outages Observed during the 2014 Polar Vortex

Pipeline Capacity Constraints

During its assessment of Building Block 2, the EPA concludes that the power industry in aggregate can support higher gas consumption without the need for any major investments in pipeline infrastructure. However, there are a few critical areas that likely will need additional capital investments. As an example, current and planned pipeline infrastructures in Arizona and Nevada are inadequate for handling increased natural gas demand due to the CPP. Pipeline capacity in New England is currently constrained, and more pipeline capacity additions will be needed as more baseload coal units retire—this is generally occurring as projected and independent of the CPP. Timing of these investments is also critical as it take three to five years to plan, permit, sign contract capacity, finance, and build additional pipeline capacity, in addition to placing replacement capacity (e.g., NGCC/CT units) in service. The proposed CPP timelines would provide little time to add required pipeline or related resource capacity by 2020.

Due to abundant availability of natural gas, the power industry is generally able to accommodate increased demand from NGCC plants that operate as baseload capacity. This higher dependence on natural gas can expose additional reliability risks, including pipeline transportation constraints that could result as more gas-fired generation is built. Overall, the increase in natural gas use and capacity expansion increases gas-electric interdependency issues and raises the following concerns:

- NGCC units could displace coal-fired generating units as baseload units, forcing less-efficient coal units out of service, further increasing demand for natural gas.
- Adequate timing is required to add new pipeline and generation resource capacity where it is needed to offset coal plant retirements and supply natural gas to new generation.
- As gas-electric dependency significantly increases, unforeseen events like the 2014 polar vortex could disrupt natural gas supply and delivery for the power sector in high-congestion regions, increasing the risk for potential blackouts.

Building Block 3 – Clean Energy

Renewable Energy

Building Block 3 describes the EPA's method to reduce CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation).

Review of EPA Assumptions and Potential Reliability Impacts

Building Block 3 includes the assumption about the preservation of nuclear generating units that are currently at risk of being retired within the next two decades due to (1) age, (2) an increase in fixed operation and maintenance costs, (3) relatively low wholesale electricity prices, and (4) additional capital investment associated with ensuring plant security and emergency preparedness. The EPA assumes that 5.7 percent of each state's nuclear generating capacity is at risk of retirement. However, the EPA included this generation as well as the five new nuclear units currently under construction (Watts Bar Unit 2 (TN), Summer Units 2-3 (SC), and Vogtle Units 3-4 (GA)) in its state-by-state CO_2 emission rate goal calculations.[20] The nuclear retirement assumptions add pressure to states that will need to retire nuclear units. For these states, more CO_2 reductions from other measures than originally estimated by the EPA may be required.

Under its draft CPP, the EPA also proposes significant expansion of non-hydro renewable generation as part of its BSER determination. The EPA adopted a methodology to estimate non-hydro renewable generation by state and year and applied these estimates in their calculation of individual state emission rate limitations. The greater the EPA's assumed non-hydro renewable generation in a given state, the lower the state's calculated CO_2 emission rate limit.

The EPA assumes that qualifying non-hydro renewable generation will grow from 213 TWh/year in 2012, to 281 TWh/year by 2020, reaching 523 TWh/year by 2030. These projections exceed the Energy Information Administration (EIA) non-hydro renewable generation forecast in their Annual Energy Outlook 2013 (AEO 2013) that grows from 202 TWh/year in 2012, to 275 TWh/year by 2020, to reach 317 TWh/year by 2030 for all sectors.[21] The EPA-assumed rapid growth in non-hydro renewable generation exceeds its own forecast in the EPA's *Regulatory Impacts Assessment* (356 TWh/year by 2030).[22]

To calculate the state target levels of renewable energy performance, the EPA examined mandatory state Renewable Portfolio Standard (RPS) requirements from the Database for State Incentives for Renewables and Efficiency (DSIRE).[23] RPS requirements vary widely by state; many states include resource-specific percentage requirements (i.e., set-asides) that promote development of certain resources in addition to their general requirements. The database distinguishes the complex web of state policies by applying them to a standardized tier system which, according to DSIRE, helps "to compare RPS policies on equal footing."[24] To determine the state effective levels in 2020, the EPA added each state's tiers together and excluded secondary and tertiary tiers that include energy efficiency or qualified fossil fuels (waste coal, carbon capture sequestration, etc.). The only RPS "type" considered was the primary type, referring to requirements for investor-owned utilities (IOUs).

Significant regional differences exist in the availability of renewable resources and their power production costs across the United States. In order to quantify these regional differences, the EPA divided the lower 48 states into six regions, based on designations by NERC Regions and ISO/RTOs. After the regions were assigned, the EPA averaged the 2020 effective levels for states that have mandatory RPS percentage standards. By applying the average regional renewable energy (RE) percentages to each region's aggregate 2012 generation, the EPA derived a new RE target generation level for 2030. The EPA notes that Alaska and Hawaii were assigned RE generation target percentages equal to the lowest value of the six regions, equivalent to the Southeast's target. The EPA assumes that RE generation will begin increasing in 2017 and continue through 2029. Moreover, they assume no growth occurs in between 2012 and 2016. The EPA derived the annual growth factor by determining "the amount of additional renewable generation (in megawatt-hours) that would be required beyond each

[20] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-33.
[21] *Annual Energy Outlook 2013* (EIA April 2013) reference case data.
[22] *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (EPA June 2014) Table 3-11 pg. 3-27.
[23] http://www.dsireusa.org/.
[24] DSIRE. DSIRE RPS Field Definitions. April 2011. http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf p.1.

region's historic (2012) generation to reach that region's RE target"[25] by 2030. This constant growth rate is then applied to each state to obtain annual state RE target levels.

The EPA's reliance on state RPS standards to compute the regional performance targets poses a variety of issues. States' main-tier RPS qualifications vary significantly and, in addition to in-state non-hydro renewable generation, also often include: hydroelectric generation, municipal solid waste (MSW), combined heat and power (CHP), clean coal, carbon capture and sequestration, and energy efficiency measures. As an example, New York has an RPS percentage of 30 percent.[26] According to the *New York Renewable Portfolio Standard Cost Study Report* produced by the New York State Department of Public Service, hydroelectricity contributes 18.25 percent of total generation and is included under baseline renewables.[27] New York's RPS percentages, therefore, include the state's hydroelectric generation as qualifying renewable resources, which is different from what the EPA assumed in its methodology.

In addition to hydroelectric power, energy efficiency plays an important role in various states' RPSs. North Carolina's RPS includes a provision that allows up to 25 percent of its target to be met by energy efficiency gains. This provision, if it were properly excluded by the EPA, would reduce North Carolina's RPS target to 7.5 percent from 10 percent, thereby lowering targets for the entire Southeast region, Alaska, and Hawaii. When establishing 2012 non-hydro renewable generation performance levels, the EPA excluded all hydroelectric generation and energy efficiency programs used in the state CO_2 emission rate calculations. The adjusted state RPS targets, as well as 2012 non-hydro RE performance levels, are used to determine the regional RE targets and regional annual growth rates.

NERC notes several other concerns with the CPP's assumption for Building Block 3, such as:

- Multipliers given to select resources' options (e.g., in-state, wind, solar, etc.). Six states (CO, DE, MI, NV, OR, and WA) give extra credit (up to 3.5 renewable energy credits per 1 MWh of energy produced) for using these resources.[28] Excluding the multiplier suggests a target that is ultimately higher than what may actually be attainable.
- The use of qualifying out-of-state renewable generation resources in effective RPS target calculations. Most RPS programs allow out-of-state qualifying renewable resources toward RPS compliance. For example, several Indiana wind projects account for nearly 50 percent of the Ohio RPS requirement. This issue is important since states realize that much of the lower-cost renewable resources may come from outside the state in locations more suitable for VERs. The underlying assumption—that the state RPS reflects in-state renewable capability that can be matched by the other states in their census region—appears incorrect and could only be dealt with via a regional state approach similar to a regional greenhouse gas initiative. In order to properly account for regional renewable resource potential, the EPA should consider including only in-state renewable resource portions of the state RPSs.
- The EPA method of assigning renewable regions is questionable. Of the six renewable regions created in the lower 48 states, targets for two regions (South Central and Southeast) were set based upon a single-state RPS. For example, the South Central state region (AR, KS, LA, NE, OK and TX) was set based upon only the Kansas RPS. Kansas accounts for only 6 percent of this region's retail power sales and has the third-best wind resources in the country. Given the combination of a low population, large land area, and very high wind resource availability, Kansas has relatively low costs to meet its RPS. However, Louisiana (ranked #48 in wind resources and double the retail sales) is assigned the same non-hydro renewable target. To put these two states in the same region sets unattainable targets for Louisiana.
- The EPA's determination of state goals for renewable generation does not fully reflect the economic aspects of renewable resources. Resource limitations exist due to permitting, market saturation, transmission access, and project financing issues. Many prime wind locations have difficulty obtaining the necessary permits and are often objected to at the local level. Many high-grade wind sites are also located in remote areas. Energy generated from

[25] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 4-18.
[26] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NY03R&re=0&ee=0.
[27] http://www.dps.ny.gov/rps/Appendix-B-2-19-04.pdf.
[28] DSIRE http://www.dsireusa.org/.

these locations requires large capital investments to build transmission infrastructure to interconnect to the BPS. Location matters, and sites with high capacity factors are limited.

- The expiration of the production tax credits (PTCs) and potential reduction of the investment tax credits (ITCs) for RE resources in the coming years will impact investment decisions and the economics of new resources. As a result, the marginal cost of new RE generation increases, which could impact the long-term development of RE resources. There is also the implicit need to increase ancillary services as a result of the increased variable resource output. Moreover, there are higher production costs associated with more non-hydro renewable generation due to a combination of increased capital costs and low-capacity operating factors. Overall, significant cost uncertainties will directly impact the electric industry's plan to quickly adapt to the CPP requirements.

Finally, grid reliability issues associated with increased variable resources are not directly addressed in the EPA's proposed Building Blocks. Conventional generation (e.g., steam and hydro), with large rotating mass, has inherent operating characteristics, or ERSs,[29] needed to reliably operate the BPS. These services include providing frequency and voltage support, operating reserves, ramping capability, and disturbance performance. Conventional generators are able to respond automatically to frequency changes and historically have provided most of the power system's essential support services. As variable resources increase, system planners must ensure the future generation and transmission system can maintain essential services that are needed for reliability.

A large penetration of VERs will also require maintaining a sufficient amount of reactive support and ramping capability. More frequent ramping needed to provide this capability could increase cycling on conventional generation. This could contribute to increased maintenance hours or higher forced outage rates, potentially increasing operating reserve requirements. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized. Nevertheless, storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[30] as the penetration of variable generation increases, maintaining system reliability can become more challenging. Additional assessments, including interconnection-wide studies, will be needed as the resource plans unfold to better understand the impacts.

If the states fall short of meeting the renewable energy targets established by the EPA, more CO_2 reductions from other measures may be required than were estimated by the EPA. These measures include more coal unit retirements, expanded natural gas-fired generation plants, or energy efficiency deployment.

The CPP proposes reductions in CO_2 emissions by investing in zero-CO_2-emitting energy sources (i.e., nuclear and non-hydro renewable generation). However, increased reliance on VERs creates reliability challenges that take considerable time to implement and require substantial changes in BPS planning and operations. Most notably, the challenges with this Building Block are:

- The CPP analysis relies on resource projections that may overestimate reasonably achievable expansion levels and exceed NERC and industry plans and do not fully reflect the reliability consequences of renewable resources.
- Increased reliance on VERs can significantly impact reliability operations and requires more transmission and adequate ERSs to maintain reliability.
- With a greater reliance on VERs, transmission and related infrastructure expansion lead times may not align with the CPP implementation timeline.

[29] See NERC's Essential Reliability Services Task Force website for more information: http://www.nerc.com/comm/Other/Pages/Essential-Reliability-Services-Task-Force-(ERSTF).aspx.

[30] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D).

Building Block 4 – Energy Efficiency

Electricity savings from enhanced energy efficiency measures are assumed as a major reduction in U.S. power generation requirements and thereby lower U.S. power industry CO_2 emissions. In calculating individual state CO_2 emission rate limits, the EPA assumes that existing state energy efficiency programs can be significantly expanded to achieve 108 TWh in cumulative savings in 2020, continue to grow to 283 TWh by 2025, and reach 380 TWh by 2030.[31] The EPA's estimated future energy efficiency program performance will have significant effects on state compliance measures and costs.

Review of EPA Assumptions and Potential Reliability Impacts

In its *Regulatory Impact Assessment*, the EPA assumes that energy efficiency will grow faster than electricity demand, with total electricity demand shrinking beyond 2020. The implications of this assumption are complex. If such energy efficiency growth cannot be attained, more carbon reduction measures would be required, primarily from reduced coal generation in most states. More low-emitting or new NGCC/CT generating capacity (not regulated under the CPP) would need to be built. Construction of new replacement capacity, as well as related infrastructure, would take time to plan, permit, finance, and build. If these needs are not identified at an early enough stage, either grid reliability or state CO_2 emission goals could be compromised.

The EPA relied on 12 state studies to set its expanded annual program target savings improvement rate at 1.5 percent per year. However, the EPA appears to overestimate most states' energy efficiency savings potential versus prior energy efficiency projections, resulting in setting performance targets too high for individual states.[32] Savings potentials are highly state specific in their consumer mix, credit for measures already taken, and levels of subsidies provided. The EPA applies one national energy efficiency growth factor to all state situations and does not consider energy efficiency program performance or cost. The discrepancies are subsequently compounded by extrapolating these annual energy efficiency performance targets as incremental improvements that can be sustained through 2030—beyond the 12 studies evaluated.

Out of 12 studies, 11 contain multiple scenarios with different sets of assumptions to demonstrate wide ranges of what is achievable under alternative financial, technological, and behavioral environments. There is no documentation on how each study's respective average annual improvement rate was calculated, which was used as the foundation to calculate the incremental performance improvement target of 1.5 percent per year.

The assumed base year is of critical importance when comparing multiple studies' achievable potential for energy efficiency. When drawing comparisons between percentages, the baseline level of electricity demand must be the same; otherwise, the total amount of energy avoided due to energy efficiency measures would be different. Under the CPP, all energy efficiency savings are applied to Business As Usual (BAU) sales forecasts generated from EIA-861 data.[33] Base years used in the 12 studies range from as early as 2007 to as recently as 2013 and are not consistent throughout the sample.[34] Comparing achievable energy efficiency potential percentages is therefore difficult, since BAU electricity demand levels are inconsistent between the studies.

Study length is another important assumption regarding the sustainability of achievable savings. It is uncertain whether the level of annual energy efficiency savings could be sustained after the expiration of the program, as the most cost-effective and impactful measures would have been utilized already—leaving only increasingly expensive incremental energy efficiency measures. The cited studies vary significantly in length: from as few as four years, to as many as 21 years.

The CPP assumes that dividing cumulative potential by the study length provides an adequate estimation for an average annual achievable potential that is sustainable over a much longer (13-year) period (2017–2030). However, there is a discrepancy in the longitudinal application of cross-sectional studies.

[31] EE savings estimates calculated using EPA's methodology, EE savings %, BAU sales estimates. Source: *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) Chapter 5.
[32] Electric Power Research Institute (EPRI) and EIA.
[33] *Annual Electric Power Industry Report* (EIA 2012) (EIA 861 Data).
[34] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-65.

The CPP assumes an average life of 10 years for energy efficiency measures. This average does not fully capture the unique distribution of the length of measures when analyzing regionally available energy efficiency measures. Key assumptions when determining energy efficiency potential are "breadth of sectors and end uses considered, study period, discount rate, pattern of technology penetration, whether economically justified early replacement of technologies is allowed for, whether continued improvement in efficiency technology is provided for,"[35] yet the EPA applies a broad average rather than determining individual measure life curves. Most of the source studies perform bottom-up approaches and evaluate thousands of permutations of measures, building types, climate zones, market penetration factors, and measure lives to determine which energy efficiency technologies to include and exclude. By approximating thousands of measure lives using one average, the CPP does not capture measure life disparities and possibly underestimates the amount of energy efficiency savings that expire throughout the compliance period.

While the studies on energy efficiency consider different potentials for the three main sectors (residential, commercial, and industrial), the CPP uses one number across all sectors in its emission rate calculation. Industrial processes are designed to use as little energy as possible in order to maximize profits of daily operations and may have already invested in energy efficiency programs, leaving minimal and costly opportunities remaining for incremental improvement. Applying the same energy efficiency potential percentage for all three sectors indirectly provides incentives for industrial utility customers to reduce their energy load proportional to residential customers, but by a much greater magnitude per capita.

The underlying state and regional studies used as the base for calculating the 1.5 percent potential include the full range of financial incentives from 25 to 100 percent, when considering base, low, and high cases. Since the EPA uses an averaging method in translating from the observed studies' sector and scenario findings to the final average annual projected potential, it is difficult to evaluate the financial incentives that are assumed in both the Building Block calculations and study results.

The EPA used the EIA's AEO 2013 baseline forecast to estimate its BAU electricity sales forecast. Growth rates calculated by the National Energy Modeling System (NEMS) region were applied to state-level 2012 retail sales from the EIA-861 survey to arrive at an annual BAU sales forecast. These growth figures include the net effect of implicit forms of energy efficiency, as that information is not explicitly presented in AEO 2013 reference case. Because the EIA does not explicitly model energy efficiency as a forecast line item, the retail sales growth is skewed for the purposes of calculating the energy efficiency Building Block.

The EIA presents some metrics to gauge energy efficiency in the AEO 2013 model results. Energy intensity, defined as energy use per dollar of GDP, represents the aggregate effects of energy consumption trends and a rising national output. Electricity energy intensity, in particular, has been on a steady decline in both consumption per dollar of GDP and consumption per capita. This is due in large part to energy efficiency, but its contribution is difficult to isolate. The EIA's AEO 2013 energy load growth projections include implicit forms of energy efficiency measures, and the proposed CPP does not appear to account for these savings. This effectively double counts the savings of some energy efficiency measures and results in state-specific energy efficiency targets that are too high to be considered reasonably achievable.

With potentially overstated expectations for energy efficiency savings, the EPA's demand forecast results in a decline in electricity use between 2020 and 2030. While other major power market forecasters' electricity sales compounded annual growth rates (CAGRs) for the period between 2020 and 2030 are strictly positive (AEO 2013: 0.7 percent, EPRI: (achievable potential) 0.4 percent, NERC average of assessment studies: 1.5 percent), the EPA assumes a CAGR of -0.2 percent for the same time period. Between 2020 and 2030, the EPA assumes incremental year-over-year reductions from energy efficiency to be almost 41 TWh nationally on average, outpacing year-over-year national electricity sales growth of 31.6 TWh, on average.

The main reason for this result is the EPA's assumption of states being able to sustain an annual incremental growth rate in energy efficiency savings of 1.5 percent once achieved. As mentioned above, this sustainability is not supported by any peer-reviewed or technical studies of energy efficiency potential.

[35] *GHG Abatement Measures* (EPA June 2014) (EPA-HQ-OAR-2013-0602) pg. 5-22.

By overestimating efficiency savings resulting in declining electricity retail sales, the results of the EPA's entire *Regulatory Impact Assessment* are concerning from a reliability perspective and have implications to electric transmission and generation infrastructure. Underlying electricity demand forecasts directly influence the required level of generation—and hence, CO_2 emissions—from existing and affected generating units under the CPP. They also affect the required new construction of generating units that are needed to meet expected electricity demand, which is projected to increase during the next 10 years.[36]

The EPA projection for energy efficiency growth at a 1.5 percent annual increase is substantially greater compared to what NERC examined in its current and prior long-term reliability assessments (LTRAs). NERC collects energy efficiency program data that is embedded in the load forecast for each LTRA assessment area. Projected annual energy efficiency growth as a portion of Total Internal Demand since 2011 has ranged from only 0.12 to 0.15 percent, as shown in the table below.

Table 1. 2011–2014 LTRA Energy Efficiency Growth

LTRA	10-Year Growth of EE (%)	Portion of Total Internal Demand (%)		Annual Growth in Relation to Total Internal Demand (%)
		Year 1	Year 10	
2011	10.7	0.59	1.63	0.12
2012	12.2	0.72	1.88	0.13
2013	11.6	0.92	2.02	0.12
2014	13.4	0.87	2.25	0.15

In summary, the CPP assumes energy efficiency gains outpace electricity demand growth through the compliance period. However, this assumption does not reasonably reflect energy efficiency achievability and is a departure from normalized forecasts. If states are unable to achieve the EPA target savings, additional CO_2 reduction measures beyond BSER measures would be needed to meet the proposed rate limits—primarily through further reductions in existing generation or expansion of natural gas and VERs. The energy efficiency assumptions underpin the CPP proposal and present the following reliability issues:

- The EPA appears to overestimate the amount of energy efficiency expected to reduce electricity demand over the compliance time frame. The results of overestimation have implications to electric transmission and generation infrastructure needs.
- Substantial increases in energy efficiency programs exceed recent trends and projections. Several sources, including but not limited to NERC, EIA, EPRI, and various utilities, have published reports, analysis, and forecasts for energy efficiency that do not align with the CPP's assumed declining demand trend.
- The CPP assumption appears to underestimate costs and may underestimate the capital investments that would be required by utilities to sustain energy efficiency performance through 2030.
- The offsetting requirements in more coal retirements, along with expansions in natural gas and VERs, in a constrained time period could potentially result in reliability or ERS constraints.

[36] *NERC 2014 Long-Term Reliability Assessment*.

Reliability Impacts Potentially Resulting from the CPP

To meet the proposed CPP emission reduction levels, the states are expected to select the mass-based limitation approach over the emission rate approach due to its greater flexibility, as well as ease to enforce and implement. The power industry has been successful in complying with prior mass-based emission cap and trade programs (e.g., Acid Rain program, Clean Air Interstate Rule, and RGGI) without creating reliability impacts. The CPP introduces potential reliability concerns that are more impactful than prior environmental compliance programs due to the extensive impact to fossil-fired generation. Additionally, there is potential for an accelerated decision-making period for the implementation of the CPP's Building Blocks. It is also important to consider the ongoing transformation to the resource mix and corresponding impacts on ERSs required to maintain a reliable BPS. State-specific carbon intensity targets create potential reliability concerns in two major areas: (1) direct impacts to resource adequacy and electric infrastructure, and (2) impacts resulting from the changing resource mix that occur as a result of replacing retiring generation, accommodating operating characteristics of new generation, integrating new technologies, and imposing greater uncertainty in demand forecasts.

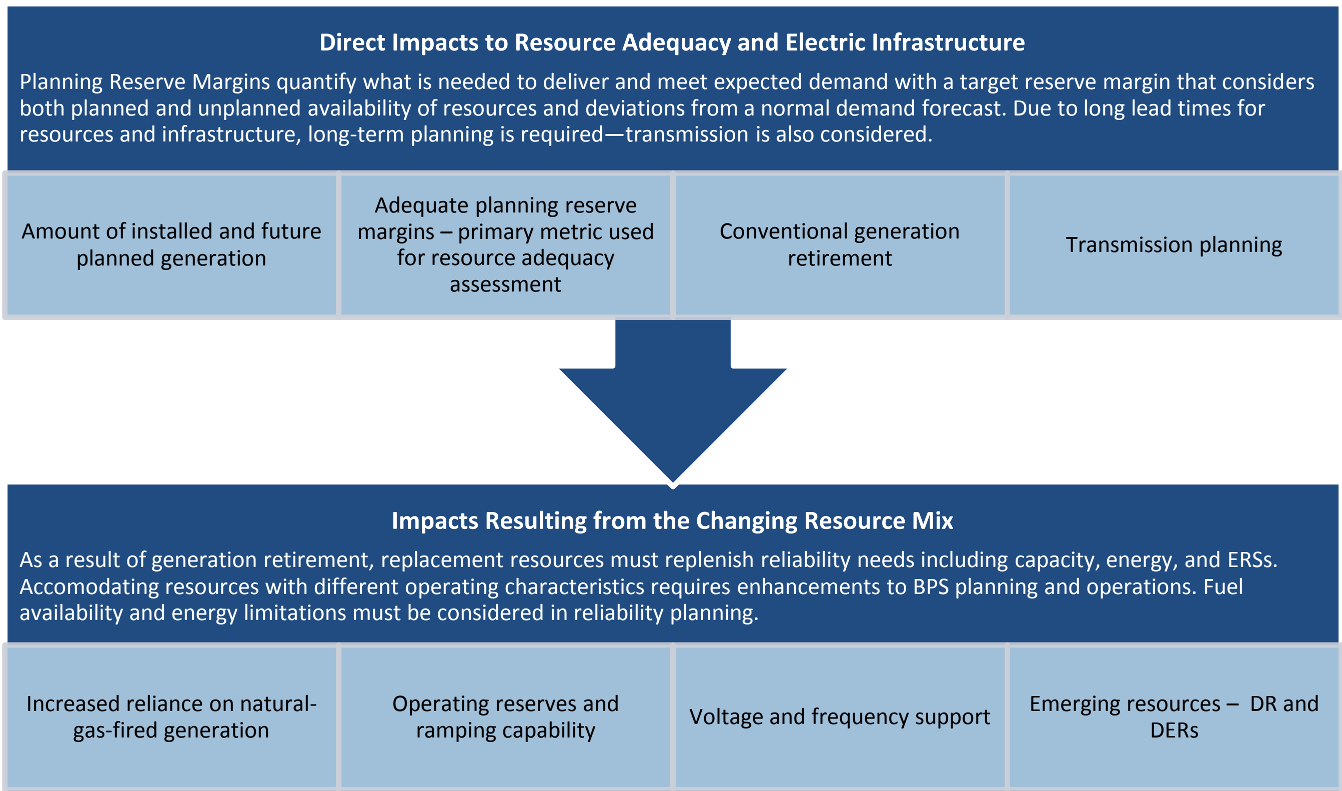


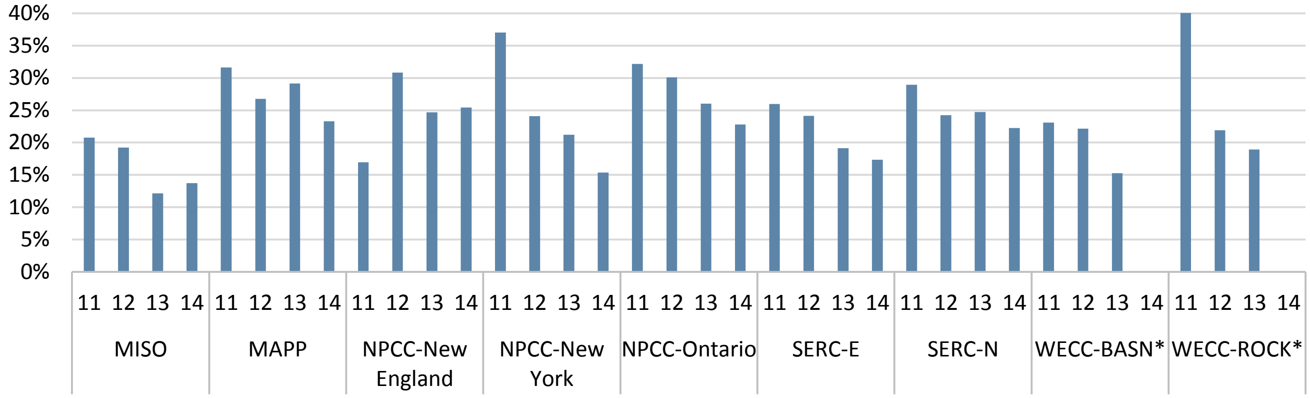
Figure 4. Summarized Reliability Challenges

Most importantly, generation (along with other system resources) and transmission must provide specific capabilities to ensure the BPS can operate securely under a myriad of potential operating conditions and contingencies, in compliance with a wide range of NERC planning and operating Reliability Standards. The above challenges warrant further consideration by policy makers. The following sections discuss these key reliability challenges in detail.

Direct Impacts to Resource Adequacy and Electric Infrastructure

Fossil-Fired Retirements Result in Accelerated Declines of Reserve Margins

In recent long-term assessments, NERC has highlighted resource adequacy concerns, particularly in ERCOT, NPCC-New York, and MISO, as projections continue to reflect declining reserve margins that fall below each area's Reference Margin Level over the next five years, despite low demand growth rate (Figure 5). As most LTRA assessment areas attribute stagnant demand growth to the ongoing projected economic indicators (typically based on either employment levels or GDP) in the residential, commercial, and industrial sectors, total capacity additions have paralleled the ongoing declines in load growth. The trend of declining margins in a number of NERC assessment areas is rooted primarily from a general reduction in 10-year capacity additions observed over the past several years. Total capacity additions continue to fall behind the ongoing declines in load growth rates (Figure 6).[37]



*Due to changes to the WECC subregional boundaries, resulting in four subregions instead of nine, the 2014 Anticipated Reserve Margins are not shown for WECC-BASN and WECC-ROCK for this comparison.

Figure 5. Short-Term (Year 2 Forecast) Anticipated Reserve Margins Show Declining Trends for Some Assessment Areas

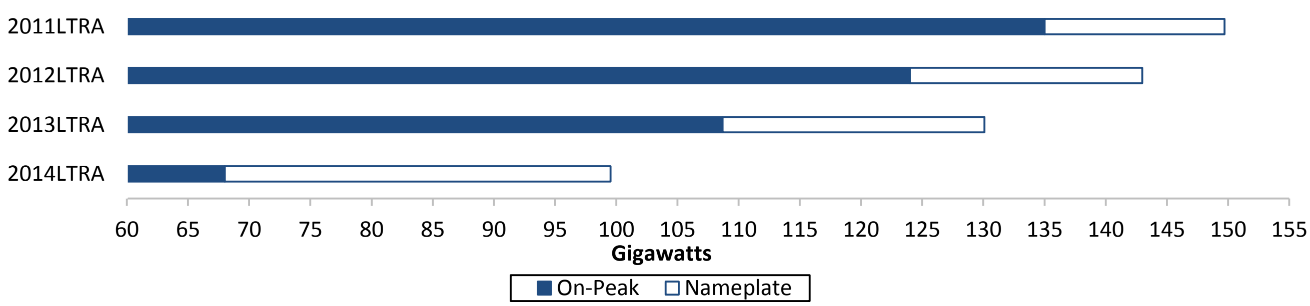


Figure 6. NERC-Wide 10-Year Projected Capacity Additions Declining Since 2011

The EPA's supporting documents estimate that up to 19 percent of the nation's coal plants will become "uneconomical" as a result of the proposed CPP. Although the CPP may not become enforceable until 2020, its effect may overshadow and change large retrofit capital decisions needed to comply with earlier EPA regulations—primarily MATS.

According to the EPA, the state implementation would result in a reduction in coal to 193 GW by 2025. The EPA finalized MATS, which is factored into *2014 LTRA* and identifies capacity retirements through 2016. In its *Technical Support Document – Resource Adequacy and Reliability Analysis,* the EPA used the Integrated Planning Model (IPM) to project likely future electricity market conditions with and without the proposed CPP. The IPM assumed that adequate transmission capacity exists to deliver any resources located in, or transferred to, the individual regions. Additionally, since most regions currently have capacity above their target reserve margins, the EPA assumed most of the retirements are absorbed by a reduction in excess reserves over time. However, uncertainty remains for a large amount of existing conventional generation that may be vulnerable to retirement resulting from additional pending EPA regulations. These retirements reduce reserve margins over the course of the CPP implementation.[38]

[37] 2011, 2012, and 2013LTRA data includes Future-Planned capacity additions http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx.
[38] EPA Technical Support Document –Resource Adequacy and Reliability Analysis http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf.

The EPA's analysis assumes the electric system will maintain resource adequacy, even with the ongoing retirements from existing regulations, including MATS. In addition, because the proposed CPP will require the development of significant amounts of new generation in a short period, additional time for infrastructure development will be needed to support these new resources. The EPA's modeling of a potential implementation scenario predicts an additional 40–48 GW of fossil-fired EGU retirements, and the addition of 21 GW of new NGCC resources.

With existing environmental regulations, the EPA's base case projections indicate that total coal-fired capacity will decline rapidly from 309.6 GW in 2013 to just 245 GW by 2016, and 243 GW by 2025. The EPA's base case—without implementation of the proposed CPP—assumes a significant reduction in coal-fired capacity by 2016: 27.2 GW beyond what is currently projected in the *2014LTRA* reference case. According to the *2014LTRA* reference case, an additional 44.2 GW of fossil-fired and nuclear capacity is projected to retire between 2014 and 2024.[39] These projections are based on the assumption that current environmental regulations will remain and do not account for potential impacts from the proposed CPP (Figure 7).

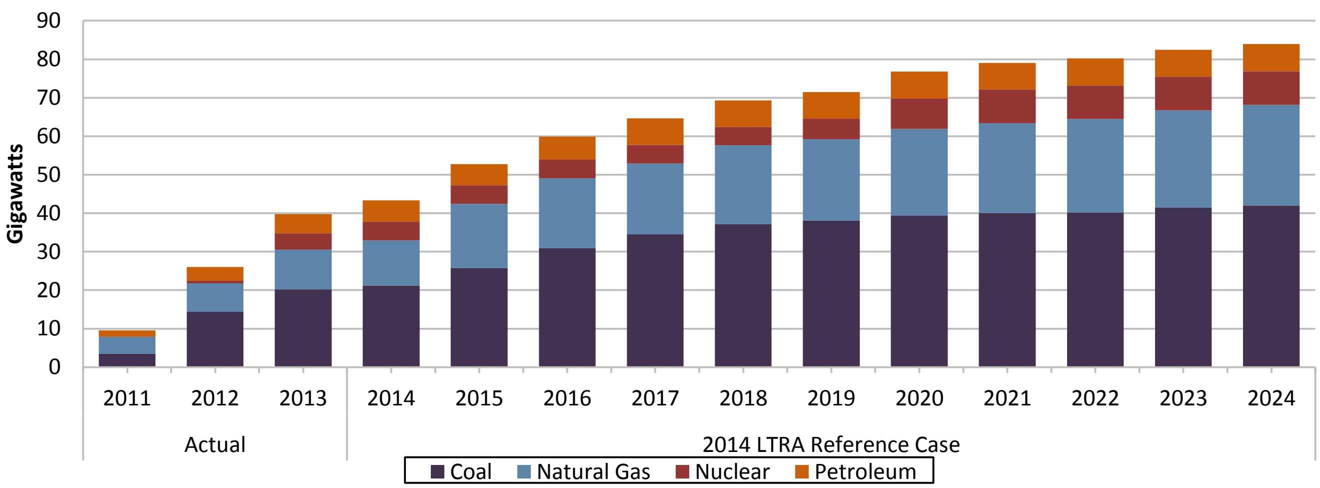


Figure 7. Cumulative Fossil-Fuel and Nuclear Retirements between 2011 and 2024 Total 83 GW

According to the EPA, the state implementation of Option 1 would result in a reduction in coal to 193 GW by 2025. Option 1 and the *2014LTRA* reference case are shown in Figure 8 and Table 2.[40]

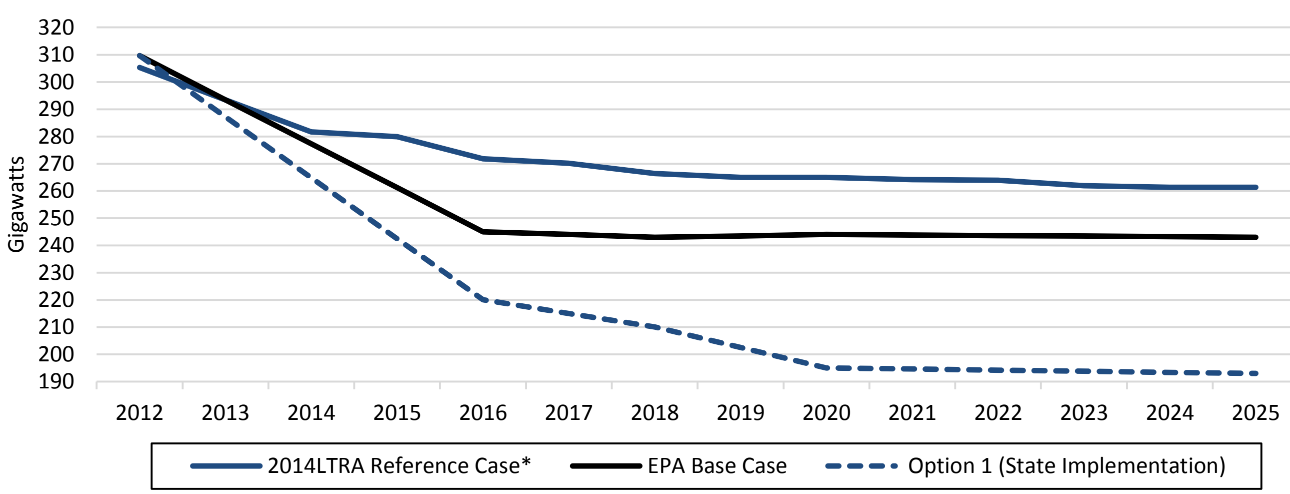


Figure 8. 2014LTRA Reference Case & EPA Power Plan Assumptions: Coal-Fired Capacity

[39] While the assessment period for the *2014LTRA* is 2015–2024, projected retirements for 2014 are included in NERC's *2014LTRA* analysis.
[40] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

Table 2. 2014LTRA Reference Case & EPA Power Plan Assumptions

NERC 2014LTRA Reference Case - Total On-Peak Capacity (GW)	2016	2018	2020	2025*
Total Coal (Existing-Certain and Tier 1 Capacity Additions)	271.8	266.4	264.9	261.3
EPA Analysis of the Proposed Clean Power Plan - Total Coal Generating Capacity (GW)	2016	2018	2020	2025
Base Case	244.6	243.3	243.6	243.3
Option 1 (State Implementation)	219.7	210.4	195.1	193.1
EPA Assumed Coal Reduction Beyond NERC 2014LTRA Reference Case (GW)	2016	2018	2020	2025
Base Case	27.2	23.1	21.3	18.0
Option 1 (State Implementation)	52.1	56.0	69.8	68.2

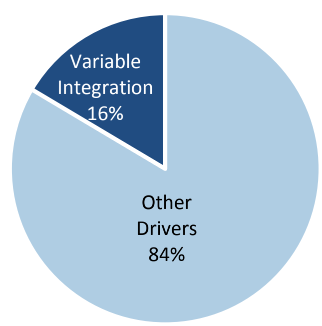
Transmission Planning and Timing Constraints

Long lead times for transmission development and construction require long-term system planning—typically a 10–15-year outlook. In addition to designing, engineering, and contracting transmission lines, siting, permitting, and various federal, state, provincial, and municipal approvals often take much longer than five years to complete. The CPP analysis assumes that adequate transmission capacity is available to deliver any resources located in, or transferred to, the region.[41] Given the significant changes and locations anticipated to occur in the resource mix, it is likely that additional new transmission, or transmission enhancements, will be necessary in some areas. New transmission lines will be required to transport the amount of renewable generation coming online, particularly in remote areas, and that creates additional timing considerations. Further, as replacement generation is constructed, new transmission may be needed to interconnect new generation. Mitigating transmission constraints identified from the proposed EPA regulations in a timely way, consistent with CPP targets, presents a potential reliability concern. Construction of new interstate high-voltage lines would require transmission owners to confer to state and federal laws with respect to environment impacts, siting, and permitting. A construction timeline for a new high-voltage line can range from 5 to 15 years depending on the voltage class, location, and availability of highly skilled construction crews. The construction of transmission assets is a very lengthy process starting from planning to the actual physical construction. It is recommended that any policies that could potentially impact the reliable operation of the transmission system also consider the associated timeline for implementing plans.

Transmission Considerations with Additional VERs

The projected 30.8 GW of additional wind and solar resources will require additional transmission to reliably integrate these resources. VERs are often built in parts of North America that are distant from the point of interconnection to the transmission system. In many cases, the location of these variable resources only meets the minimum voltage support requirements. According to the 2014LTRA Reference Case, 16 percent of new transmission projects (under construction, planned, or conceptual) identify variable resource integration as a primary driver.

New Transmission Project Drivers



The location of additional transmission resources will be informed by the outcome of the transmission planning studies. The transmission planning process will not be able to fully incorporate the impacts of potential retirements until those resource addition requirements are made known to the system operator. For ISO/RTOs, this will likely not happen until the final state plans are developed.

To support variable generating capacity increases, the power industry would need to invest heavily to expand transmission capacity to access more remote areas with high-quality wind resources. Developing a resource mix that has sufficient ERSs to support integration and reliable BPS operation is also a consideration. Given the natural wind variability in these locations, incremental wind project resources would have relatively low capacity factors (20–35 percent) that would require complex financial decisions to support transmission capacity.

[41] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

NERC anticipates that after the CPP guidelines are finalized in 2015, and SIPs are developed and approved by the EPA in 2016/2017, entities will work with their state utility commissions or other appropriate governing entities to assess resource and system options. Extensive transmission reliability screening assessments will be performed to support these decisions and will include comprehensive local and regional reliability analyses, which must be coordinated with states and neighboring entities. As resource decisions are made, reliability screening will transition into the established NERC reliability assessment processes. Consistent with the NERC Reliability Standards, transmission enhancements to address reliability constraints will be identified, incorporated into transmission expansion plans, and coordinated with other projects locally and regionally. Because committed transmission projects typically require three to five years to be completed, and often longer for major projects with significant right-of-way needs, NERC is concerned that reliability-related enhancements may not be able to be completed for a 2020 implementation.

Initial Regional Reliability Assessment of the Proposed CPP

Some regions started an initial reliability assessment of the proposed CPP focused on their respective footprints to better understand the plan's potential impacts. The initial analyses are slightly different in focus and are in varying stages of development. The key findings from recent MISO and SPP studies are provided below.

MISO

MISO focused primarily on generation capacity impacts. MISO, which is based on a 14.8 percent reserve margin requirement determined by the 1-day-in-10-year loss-of-load event, projects that in in 2016 it will operate at the reliability level of approximately 2-days-in-10-year loss-of-load event, increasing the likelihood that resources will not be sufficient to serve peak demand. The number of expected days per year of a loss-of-load event is projected to increase throughout the assessment period. The proposed CPP could further exacerbate resource adequacy concerns in the MISO footprint unless additional replacement capacity is built in a timely fashion.[42] Additionally, the analysis showed that the EPA's carbon proposal could put an additional 14,000 MW of coal capacity at risk of retirement. This amount is beyond the 12,600 MW within MISO's footprint that is slated to retire by the end of 2016 to comply with MATS.[43] The contributing factors driving the projected deficit include:

- Increased retirements and suspensions (temporary mothballing) due to EPA regulations and market forces and low natural gas prices
- Exclusion of low-certainty resources that were identified in the resource adequacy survey
- Exclusion of surplus of capacity in MISO South above the 1,000 MW transfer from the Planning Reserve Margin requirement (PRMR)[44]
- Increased exports to PJM and the removal of non-Firm imports[45]
- Inadequate Tier 1 capacity additions [46]

[42] Anticipated Reserve Margin includes operable capacity expected to be available to serve load during the peak hours with firm transmission. Prospective Reserve Margin operable capacity that could be available to serve load during the peak hour, but lacks Firm transmission and could be unavailable for a number of reasons.

[43] MISO GHG Regulation Impact Analysis – Initial Study Results.

[44] For this assessment, 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of regulatory issues currently under FERC review.

[45] Capacity sales (imports and exports) in MISO depend on decisions of the respective resource owners, assuming that the tariff requirements are met (including planning of necessary transmission of both the buying and selling areas). Regarding the removal of non-Firm imports, the MISO market monitor double-counted non-Firm imports in the 2013LTRA reference case. These imports are accounted for in the Reference Margin Level (PRMR).

[46] In the MISO footprint, 91 percent of the load is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Necessity (CPCN).

SPP

SPP looked at both generation capacity and transmission reliability impacts of the proposed CPP.[47] The initial study indicated that compliance with the carbon regulations, if implemented as modeled by the EPA, will not be possible without significant investment in new generation and associated major improvements to both the electric transmission and natural gas infrastructure to accommodate new generation. The results indicate that by 2020, SPP's anticipated reserve margin would be 5 percent, representing a capacity margin deficit of approximately 4,500 MW. By 2024, 10,000 MW beyond current plans would be needed to maintain their reserve margin. Given the 8- to 10-year timeline needed to plan for and construct these additional resources, SPP has concluded that there is not sufficient time to achieve compliance with the EPA's interim goals, and that widespread reliability impacts are likely.

The reliability issues identified in the initial studies will require significant upgrades to the transmission infrastructure to maintain system reliability, accommodate new generation or, when new generation is not warranted, to support the dispatch of the system in a manner significantly different from historical operations. Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.

Reliability Assurance

NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Therefore, NERC supports policies developed by the EPA, FERC, the DOE, and state utility regulators that include a "reliability assurance mechanism," such as a reliability back-stop, to preserve BPS reliability and manage emerging and impending risks to the BPS.

Many utilities and ISO/RTOs have discussed a possible reliability safety valve similar to the one-year compliance extension that has been used to avoid retirement-related reliability impacts from the MATS compliance deadline. A reliability safety valve will be of limited utility if the EPA's proposal is implemented as currently designed, and it appears the EPA has far more flexibility under Section 111(d) than was available under the Section 112 program. Accordingly, a set of reliability assurance provisions that may include a reliability backstop, as well as other measures, would be recommended to maintain BPS reliability.

Stakeholders expressed to NERC staff their concerns regarding the need for additional time to mitigate the impacts of the carbon regulation. The proposed timeline does not provide enough time to develop sufficient resources to ensure continued reliable operation of the electric grid by 2020. To attempt to do so would increase the use of controlled load shedding and potential for wide-scale, uncontrolled outages. Additionally, policy changes may be required to ensure the Planning Coordinators and Transmission Planners perform the necessary studies and exercise the authority to implement transmission and related infrastructure solutions and assure that ERSs are provided in a timely manner.

[47] SPP Reliability Assessment of EPA 111(d) Clean Power Plan Rule http://www.spp.org/publications/SPC%20Materials%20081914.pdf.

Direct Impacts to Resource Adequacy and Electric Infrastructure
Summary and Recommendations

Fossil-Fired Retirements and Accelerated Declines in Reserve Margins: Despite low demand growth, NERC has highlighted resource adequacy concerns as projections continue to reflect declining reserve margins that fall below the Reference Margin Level in three assessment areas within the next five years.

- *The Regions, ISO/RTOs, and states should perform further analysis to examine the potential resource adequacy concerns.*

Transmission Planning and Timing Constraints: The proposed CPP implementation is currently scheduled to begin in mid-2016. Some reliability impacts could be mitigated by the construction of new (or enhancement of existing) transmission facilities; however, long lead times (e.g., 10 years) are required for transmission planning and construction.

- *The EPA and states, along with industry, should consider the time required to integrate potential transmission enhancements and additions necessary to address impacts of the proposed CPP.*

Regional Reliability Assessment of the Proposed CPP: To better understand its potential impacts, some Regions have started an initial reliability assessment of the proposed CPP focused on their respective footprints. The initial analyses are slightly different in focus and are in varying stages of development.

- *Other ISO/RTOs, states, and Regions should prepare for the potential impacts to grid reliability, especially related to the time required to plan and build transmission infrastructure.*

Reliability Assurance: NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS.

- *The EPA, FERC, the DOE, and state utility regulators should employ the array of tools at their disposal and their regulatory authority to develop reliability assurance mechanisms such as a reliability back-stop. These mechanisms include timing adjustments and granting extensions where there is a demonstrated reliability need.*

Impacts Resulting from the Changing Resource Mix

Coal Retirements Increase Reliance on Natural Gas for Electric Power

The electricity sector's growing reliance on natural gas raises concerns regarding the electricity infrastructure's ability to maintain system reliability when facing a constrained natural gas capacity for delivering natural gas to electric power generators. These concerns are already being articulated in light of gas-electric dependency studies and analyses, and include ISO/RTOs, electricity market participants, industrial consumers, national and regional regulatory bodies, and other government officials.[48] The extent of these concerns varies from region to region; however, concerns are most acute in areas where power generators rely on interruptible pipeline transportation as the natural gas use for generation rapidly grows.

Under the CPP, an accelerated shift in the power generation mix from coal to natural gas is expected to ensue. The EPA's state limitation calculations assume a 440 TWh/year shift to existing NGCC generation from coal (376 TWh/year) and older oil-gas steam (64 TWh/year) generators due to redispatched NGCC units up to a 70 percent capacity factor. In its *Regulatory Impact Assessment*, the EPA projects that the natural gas market portion of total U.S. power generation will grow from 29 percent energy in 2013 to 33–34 percent from 2020 to 2030. In an analysis of the CPP prepared by Energy Ventures Analysis (EVA), natural gas generation is found to increase by an additional 400–450 TWh/year and increase the gas generation energy market share to reach 35 percent in 2020, 39 percent in 2030, and 49 percent in 2040.[49]

As reliance increases more on natural gas for both baseload and on-peak capacity, it is important to also examine potential risks associated with reduced diversity and increased dependence on a single fuel type. Currently, natural-gas-fired resources account for large portions of both the total and on-peak resource mix in several assessment areas when considering both existing capacity and planned additions (Table 3).

Table 3. Assessment Areas with Natural-Gas-Fired Capacity Accounting for Over One-Third of Existing Nameplate Capacity[50]

	Nameplate Capacity (GW)		On-Peak Capacity (GW)		10-Year Nameplate Capacity Additions (GW)		
Assessment Area	**Gas-Fired**	**Portion of Total**	**Gas-Fired**	**Portion of Total**	**Tier 1**	**Tier 2**	**Tier 3**
FRCC	40.2	64%	33.9	63%	10.1	0.0	0.0
MISO	69.0	39%	58.7	41%	2.8	0.0	10.0
NPCC-New England	18.6	54%	13.3	43%	1.1	3.3	0.0
NPCC-New York	21.0	55%	14.2	40%	0.0	3.5	0.0
PJM	80.0	43%	56.5	32%	10.0	47.5	0.0
SERC-SE	31.2	47%	28.4	46%	0.0	0.0	2.6
SPP	32.3	40%	30.2	47%	1.1	0.7	5.7
TRE-ERCOT	48.4	54%	45.2	63%	4.9	21.5	0.0
WECC-CA/MX	47.7	61%	43.9	70%	5.5	6.2	0.9
WECC-RMRG	7.2	36%	6.2	41%	1.2	0.0	0.0
WECC-SRSG	19.5	47%	16.3	50%	0.6	1.0	3.0

With this shift toward more natural gas consumption in the power sector, the power industry will become increasingly vulnerable to natural gas supply and transportation risks. Extreme conditions, although rare, must be studied and integrated in planning to ensure a suitable generating fleet is available to support BPS reliability. While there are several plants with dual-fuel capability, the capability to switch to a secondary fuel can be limited during certain operating conditions.

Overdependence on a single fuel type increases the risk of common-mode or area-wide conditions and disruptions, especially during extreme weather events. Disruptions in natural gas transportation to power generators have prompted the gas and electric industries to seek an understanding of the reliability implications associated with increasing gas-fired generation. For example, adverse winter weather, such as that experienced during January 2014, provided signs of natural gas supply and deliverability risks.[51] This can be a local issue in areas where there is already a heavy concentration of natural gas generation.

[48] See NERC's Special Reliability Assessments on electric and gas interdependencies for more information and recommendations: Phase I and Phase II.

[49] Energy Ventures Analysis: FUELCAST – The Long-Term Outlook 2014, October 2014.

[50] Tier 1, 2, and 3 Capacity Category Definitions are provided in the *2014 Long-Term Reliability Assessment.*

[51] NERC Polar Vortex Review Report
http://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

While several gas pipeline construction projects are underway to increase gas deliverability, the CPP proposal accelerates the shift toward more natural gas generation and could create additional pipeline needs. The increased demand can be addressed with sufficient lead time (i.e., more than three years), which is needed to plan, collect contracts, permit, procure, and build new pipeline. To the extent that the CPP assumptions regarding natural-gas-fired capacity expansion and existing coal-fired generation retirements are achieved, the gas and electric sectors will lean more heavily on each other.

The Availability of Essential Reliability Services Is Strained by a Changing Resource Mix

The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. The state calculations assume that non-hydro renewable capacity could grow rapidly by 5 percent per year, from 218 TWh/year in 2012 to reach 523 TWh/year by 2030. This incremental renewable generation represents well over twice the energy currently supplied by VERs and would be dominated mostly by new wind, and to a lesser extent, new solar capacity.

In addition, wind projects will significantly increase the demand for reactive power and ramping flexibility. Ramping flexibility will increase cycling on conventional generation and often results in either increased maintenance hours or higher forced outage rates—in both cases, increased reserve requirements may result. While storage technologies may help support ramping needs, successful large-scale storage solutions have not yet been commercialized.[52] Storage technologies support the reliability challenges that may be experienced when there is a large penetration of VERs, and their development should be expedited.

Based on industry studies and prior NERC assessments,[53] as the penetration of variable generation increases, maintaining voltage stability can be more challenging. Additional studies will be needed to further understand potential challenges that may indirectly result from the proposed CPP. In its role of assessing reliability, NERC commissioned the Essential Reliability Services Task Force (ERSTF) with members from NERC's Planning Committee and Operating Committee to study, identify, and analyze the planning and operational changes that may impact BPS reliability. NERC, under the ERSTF work plan and activities, has issued an initial assessment of ERSs that identifies ERS reliability building blocks as a foundational approach for further assessment and studies.[54]

Increased Penetration of Distributed Energy Resources

The EPA projects that retail electricity prices will increase by $1/MWh to $18/MWh under the CPP[55] as a result of a combination of higher natural gas prices and the implementation of new carbon penalties on impacted fossil-fired generators.[56] As retail power prices increase, some existing customers may install DERs, when economically advantageous. Depending on the price advantage, the market penetration of DERs could be substantial, creating potential reliability impacts for grid operators that lack visibility and control of these resources. Given that DERs displace grid retail sales, DERs could become a larger grid capacity planning challenge since the grid will remain responsible for being the DER site's back-up power supplier. Reliability issues with large onsets of non-dispatchable resources have already created operational challenges in California, Hawaii, and Germany. Such experienced reliability challenges are:

- The loss of inertia and the loss of generating units used to control transient instability driven by the significant non-controllable generation and lack of sufficient attention to ERSs—Hawaii.

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[52] Pumped storage offers fast and large ramping capabilities to the BPS; however, increases in this technology is not likely due to land restrictions, permitting limitations, and environmental opposition. Less than 1 GW of pumped storage capacity is projected over the next 10 years.

[53] NERC-CAISO Joint Report: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach; other industry reports include those developed by the Integration of Variable Generation Task Force (IVGTF); Integrating Variable Renewable Energy in Electric Power Markets: Best Practices from International Experience (Appendix D)

[54] NERC Essential Reliability Services Task Force - A Concept Paper on Essential Reliability Services that Characterize Bulk Power System Reliability http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF_Draft_Concept_Paper_Sep_2014_Final.pdf

[55] *Regulatory Impacts Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014) and supporting IPM Model documentation and data.

[56] According to EIA, closing coal plants will drive up natural gas prices by 150 percent over 2012 levels by 2040, this cost rise will cause electricity prices to jump seven percent by 2025 and 22 percent by 2040. Because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices. 2014 Annual Energy Outlook.

- DERs only operate within frequency ranges that are in many cases close to nominal frequency and, therefore, frequency and voltage ride-through capabilities are needed—Germany.
- Increased wind and solar levels that mandate increased ramping, load-following, and regulation capability—this applies to both expected and unexpected net load changes. This flexibility will need to be accounted for in system planning studies to ensure system reliability—California.

Studies and Assessments Needed to Support Reliability

The following assessments are needed to form a complete reliability evaluation. Table 4 provides a list of the types of studies and analysis that must be done to demonstrate reliability, recognizing that the industry does not operate the grid without a thorough and complete analysis.

Table 4. Study and Assessment Types Needed for a Complete Reliability Evaluation

Local Reliability Assessments	Area/Regional Reliability Assessments
• Specific generator retirement studies	• Resource adequacy
• Specific generator interconnection studies	• Power flow (regional)
• Specific generator operating parameters	• Stability and voltage security (regional)
• Power flow (thermal, voltage)	• Gas interdependencies; pipeline constraints
• Stability and voltage security	• Operating reserves and ramping
• Offsite power for nuclear facilities	• System restoration/blackstart

Impacts Resulting from the Changing Resource Mix
Summary and Recommendations

Coal Retirements and the Increased Reliance on Natural Gas for Electric Power: As the industry relies more on natural-gas-fired capacity to meet electricity needs, close examination will be necessary to ensure risks have been fully identified and evaluated. Potential issues are most acute in areas where power generators rely on interruptible natural gas pipeline transportation.

- *Further coordinated planning processes between the electric and gas sectors will be needed to ensure a strong and integrated partnership. Coordinated planning processes should include considerations for pipeline expansion to meet the increased reliance on natural gas for electric generation—especially during the extreme weather events (e.g., polar vortex).*

The Changing Resource Mix and Maintaining Essential Reliability Services: The proposed CPP provides states and developers additional incentives to rapidly expand their non-hydro renewable capacity to displace existing coal generation. Resource adequacy assessments do not fully capture the ERSs needed to reliably operate the BPS and are generally limited to identifying supply and delivery risks.

- *ISO/RTOs, utilities, and Regions, with NERC oversight, should analyze the impacts to ERSs in order to maintain reliability. Additionally, system operators and ISO/RTOs need to develop appropriate processes, tools, and operating practices to adequately address operational changes on the system.*
- *NERC should perform grid-level performance expectations developed from a technology-neutral perspective to ensure ERS targets are met.*
- *The development of technologies (such as electricity storage) help support the reliability objectives of the BPS, and these technologies should be expedited to support variability and uncertainty on the BPS.*

Increased Penetration of Distributed Energy Resources: A potential risk in additional DERs is the temporary displacement of utility-provided service, which could create additional planning challenges, considering utilities must act as a secondary supplier of electricity.

- *ISO/RTOs and system planners and operators should consider the market penetration of DERs and potential reliability impacts due to the limited visibility and controllability of these resources.*

Conclusions

This report represents NERC's initial review of reliability concerns regarding the EPA's proposed Clean Power Plan (CPP) under Section 111(d) of the Clean Air Act. As the CPP is finalized and implemented, NERC will develop special reliability assessments in phases. This initial evaluation highlights the underlying CPP assumptions and identifies a range of potential reliability impacts of the CPP on the BPS. It is NERC's intention that this document be used as a platform by industry stakeholders and policy makers to discuss technically sound information about the potential reliability impacts of the proposed CPP.

The Building Block assumptions in the EPA's proposed CPP are critical to NERC's evaluation of the reliability impacts. NERC will provide independent assessments of the BPS under a wide range of conditions that reflect the implications of the proposed policy, varied resource mixes, and impacts to transmission and will share the results with the industry and states as they develop their implementation plans.

Recommendations

1. **NERC should continue to assess the reliability implications of the proposed CPP and provide independent evaluations to stakeholders and policy makers.**
   The NERC Board of Trustees endorsed a plan for the review and assessment of the reliability impacts of the EPA proposal at its August 2014 Board meeting. The NERC Planning Committee should lead NERC and industry efforts in conducting the reliability assessments and scenario analyses as identified in this report. NERC will work through its stakeholder process to solicit industry input on assessment approaches and assumptions as further special assessments and evaluations are developed.

2. **Coordinated regional and multi-regional industry planning and analysis groups should immediately begin detailed system evaluations to identify areas of concern and work in partnership with policy makers to ensure there is clear understanding of the complex interdependencies resulting from the rule's implementation.**
   Given the potential reliability concerns of the EPA's 2020 proposed implementation date, NERC encourages the states to begin operational and planning scenario studies, including resource adequacy, transmission adequacy, and dynamic stability, to assess economic and reliability impacts. A number of studies and analyses must be performed to demonstrate reliability, and industry must closely coordinate with the states to ensure the SIPs are aligned with what is technically achievable within the known time constraints. Additionally, industry should review system flexibility and reliability needs while achieving the EPA's emission reduction goals. As a result, states that largely rely on fossil-fuel resources might need to make significant changes to their power systems to meet the EPA's target for carbon reductions while maintaining system reliability.

3. **If the environmental goals are to be achieved, policy makers and the EPA should consider a more timely approach that addresses BPS reliability concerns and infrastructure deployments.**
   NERC Reliability Standards and Regional Entity criteria must be met at all times to ensure reliable operation and planning of the BPS. Based on NERC's initial review, more time would be needed in certain areas to ensure resource adequacy, reliability requirements, and infrastructure needs are maintained. The EPA, FERC, the DOE, and state utility regulators should consider their regulatory authority to make timing adjustments and to grant extensions to preserve BPS reliability. NERC supports policies that include a reliability assurance mechanism to manage emerging and impending risks to the BPS, and urges policy makers and the EPA to ensure that a flexible and effective reliability assurance mechanism is included in the rule's implementation.