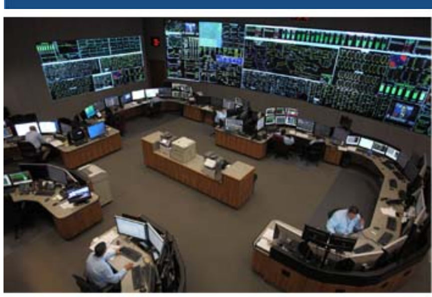
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Considerations for Clean Power Plan Development

January 2016

RELIABILITY | ACCOUNTABILITY

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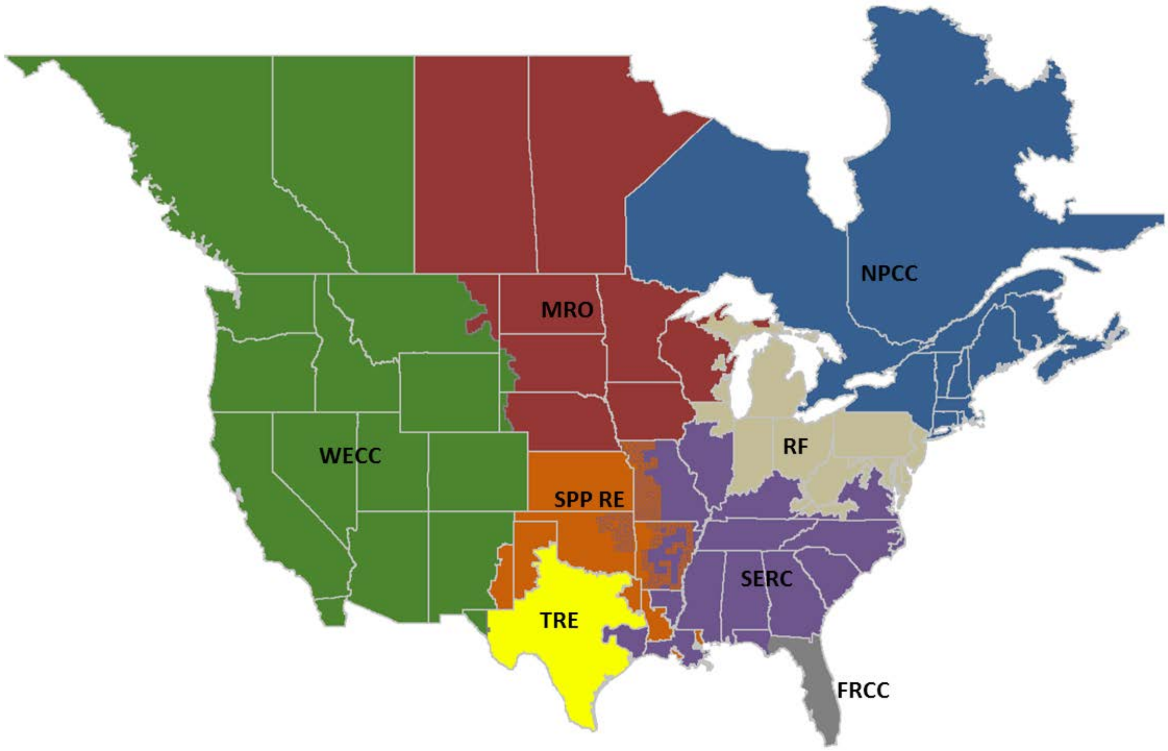
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.



The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

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

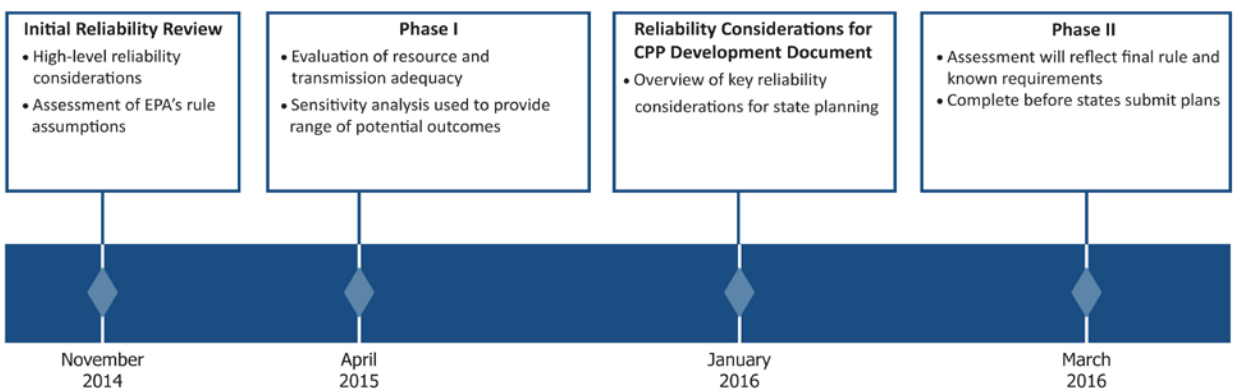
Executive Summary

The purpose of this report is to inform state regulators, environmental regulators, and executive offices about Bulk Power System (BPS) reliability considerations as they formulate their state implementation plans to comply with the Clean Power Plan (CPP).

The U.S. Environmental Protection Agency (EPA) issued its final rule, titled *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, on August 3, 2015.[1] The rule establishes limits on CO_2 emissions for existing electric generation facilities, thereby accelerating the ongoing transformation of the resource mix. State officials have a great deal of experience working with utilities, ISO/RTOs, NERC, and Regional Entities to address energy, environment, and reliability challenges and opportunities. This transformation is calling for new levels of coordination and cooperation by all parties to ensure a smooth and reliable transition.

In 2014, NERC's Board of Trustees directed NERC staff to develop a series of special reliability assessments to identify potential risks and identify key considerations to sustain BPS reliability during implementation of the CPP rule. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. In its role as the Electric Reliability Organization[2] (ERO) in the United States, NERC has responsibility under Section 215 of the Federal Power Act to conduct assessments of the reliability and adequacy of the BPS (the high-voltage transmission and generation system). The CPP as issued by the EPA applies only to the lower 48 contiguous United States, and this report provides guidance to those affected states.[3] In addition to this report, NERC is conducting a detailed reliability assessment of the final CPP rule for release in March 2016.

NERC Special Assessments of the EPA Clean Power Plan



NERC's assessments provide a technical platform for important policy discussions on reliability challenges facing the interconnected North American BPS. As emerging risks and potential impacts to reliability are identified, special assessments are conducted that provide insights and recommendations for maintaining and considering reliability. As part of its assessment obligations, NERC annually reviews and assesses the electric industry's long-term resource and transmission plans. State compliance plans will ultimately be included in the long-term planning process; however, at this time, no state has yet to file a plan.

The CPP final rule calls for an explicit consideration of reliability as part of the state plan submittal. Individual state plans and their impact to reliability will be difficult to assess as electric systems are planned and operated across

[1] The rule is issued under Section 111(d) of the Clean Air Act and establishes limits on CO_2 emissions for existing electric generation facilities. https://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf

[2] NERC and the eight Regions were selected by FERC in 2006 to serve as the U.S. Electric Reliability Organization (ERO).

[3] At present it will only apply to 47 states as Vermont and DC do not have any qualifying EGUs.

many state boundaries. While state plans will ultimately be integrated into broader regional plans, this will likely occur beyond 2018. The first submittal deadline for state implementation plans is September 2016, and an EPA acceptance of a state extension request would extend that deadline to September 2018. In an effort to support policy makers ahead of these deadlines, NERC and the Regional Entities are available to provide information to states as they consider plans to comply with the CPP.

The BPS is already undergoing a broad transformation with retirements of coal units and some nuclear units, and additions of resources fueled by natural gas, wind, and solar. Distributed generation, energy efficiency, and demand response are also changing the way in which system planners must account for resources. The CPP has the potential to hasten the transformation of the electric system started by market and political factors such as natural gas supply and pricing and federal and state policy decisions with respect to renewables and energy efficiency and other environmental regulations.

NERC has identified aspects of plan design that need to be considered to reliably accommodate this broad transformation. This is not an all-inclusive review of reliability considerations. Rather, this document is intended to underscore the elements of reliability that states need to consider as CPP implementation plans are developed.

Key Reliability Considerations

- **State Coordination with System Planning Entities –** Coordination between states, utilities, ISO/RTOs, and regional planning entities is essential to share and calibrate common reliability objectives and identify reliability pathways that accommodate resources called for in CPP implementation plans. Many neighboring states share electric system connections, and policy decisions in one state can impact another state's infrastructure and reliability needs. The interconnected system requires that NERC Planning Coordinators and Transmission Planners coordinate system planning and, therefore, these entities are an essential component to the development of state plans.
- **Essential Reliability Services –** Changes to the generation resource mix and the way in which resources are dispatched and controlled can impact system operations. In order to maintain an adequate level of reliability through this transition, generation resources need to provide sufficient voltage control, frequency support, and ramping capability—essential components to the reliable operation of the BPS. It is necessary for policy makers to recognize the need for these services by ensuring that interconnection requirements, market mechanisms, or other reliability requirements provide sufficient means of adapting the system to accommodate large amounts of variable and/or distributed energy resources (DERs). Whereas distinct market mechanisms and wholesale services are regulated by FERC, states plan for policies on resource mix and establishing Reserve Margin requirements.
- **Timing Considerations for Energy Infrastructure Development –** The existing transmission system was planned and designed to support the existing generation fleet, which is comprised mostly of larger, central-station electric generation. Therefore, accommodating new resources, particularly those located in areas different from the existing fleet, transmission lines, facilities, and/or other transmission elements will likely be necessary. There is uncertainty in the timing associated with approval and construction of resource additions and related transmission system infrastructure that may be vital to support state implementation plans. Retirements can happen quickly, but adequate replacement facilities must be in service prior to retirement. As natural gas-fired generation replaces coal-fired generation the requisite timeline for natural gas pipeline infrastructure becomes even more relevant. State plan designers should work with stakeholders in their respective states to understand how components of their implementation plans may need to be adjusted to support continued BPS reliability, the need and timing requirements for any additional energy infrastructure and how these items relate to compliance timelines.
- **Electricity Imports and Exports –** State plans will require coordinated assessments of transmission system impacts and effects on the import and export capabilities of nearby systems. In addition to other regulatory

factors that affect the decision to operate individual generating units, a state's import and export options may further complicate the analysis of compliance strategies. If a state intends to use resources from nearby states as part of a compliance strategy, it is important to determine if the necessary transmission capability is available to reliably transport electricity from those resources.

- **Change in Generator Cycling and Operations –** The requirements of the CPP will impact the selection of generators that are operated, as well as when they run and at what output level. While coal-fired generators have typically been operated as baseload units, a state implementation plan that increases use of gas-fired generation and reduces coal-fired generation may result in coal plants serving seasonal peak demand needs. Due to these changes in operating conditions, states should take account of changes in maintenance requirements likely due to cycling and the risk of increased forced outages of these coal-fired plants. Additionally, increased and sufficient coordination between gas and electric system operators becomes much more critical to ensure adequate amounts of fuel are available.
- **Reserve Margin Assessment –** Compliance with the CPP accelerates an ongoing shift in the generation mix, with retirements of baseload generators and additions of variable energy resources (VERs). Increasing energy limitations (e.g., limitations on coal unit dispatch due to CO_2 targets and uncertainty in solar and wind production) can significantly change a resource adequacy assessment. A comprehensive assessment of resource capacity contributions with more sophisticated analysis methods is needed to properly account for conventional resources, VERs, DERs, and Demand Response. Particularly during this transition, Reserve Margin and resource adequacy requirements must be calibrated with the resources that are on the system. As more variable and energy-limited resources are added, the system will likely require additional reserve capacity to maintain a similar level of reliability compared to a system with all conventional generation.
- **Energy Efficiency –** Energy efficiency (EE) plays an important role in the reduction of load requirements on the electric system. Although evaluation, measurement, and verification (EM&V) methods are improving, there is still limited visibility into the true level of capacity displacement that EE can achieve. Given that EE can be used as a potential CPP compliance tool, it is important that states evaluate the realistic potential for EE to displace load and the likely duration of those impacts. Shorter term EE measures may serve as a potential bridge to meet CPP requirements.
- **Emissions Trading –** In general, emissions trading promotes additional reliability compliance options by effectively broadening the compliance region as well as the availability of allowances and credits. However, some resource options that might be assumed available through emissions trading may not be, due to another state's plan. Because trading is optional, states should coordinate to ensure the most beneficial approach of trading is considered.
- **Reliability Safety Valve –** The EPA has provided for a Reliability Safety Valve (RSV) to be used for unexpected delays or to address impacts from catastrophic events. At various points during the RSV process, states must coordinate with the relevant reliability coordinator and/or planning entity and report that coordination to the EPA. A memorandum between the EPA, the DOE, and FERC pledges that the three federal entities will to work together to monitor implementation, share information, and resolve difficulties. States must understand how the Reliability Safety Valve works and its limits, recognizing that it cannot be used as a planning tool to meet CPP requirements.
- **North American and European Precedents –** North America has informative examples of carbon trading programs (such as RGGI, the Regional Greenhouse Gas Initiative in certain Northeastern and Mid-Atlantic states) and transitions from coal-fired generation to other resources (as in Ontario). Europe has also experienced a large shift toward renewable and distributed resources. While a disturbance demonstrated the need for focused planning and infrastructure investments, Europe is transforming its power system to reduce carbon emissions while maintaining reliability. States should review these precedents as case studies for potential strategies, lessons learned in implementation, and insights as they develop their plans.

State Coordination with System Planning Entities

There are two fundamental types of planning entities for utilities within the United States. One type is based on the presence of an independent system operator/regional transmission organization function (ISO/RTO model) that typically includes an independent market management function that does not own the assets being operated. The second consists of vertically integrated utilities, where owners hold both generation and transmission assets and also have direct operational control of such assets. Both types of planning entities have a substantial role in planning the transmission system.

Collaborative interaction between the state plan designers and planning entities is essential to a successful implementation of state plans that comply with CPP and maintain reliability. The interaction with the system planning entity will be different depending on which model is present in a given state. Some states have portions of their footprints covered by planning entities using each model.

The EPA has encouraged collaboration with planning entities in the development of state implementation plans. To understand the opportunities for coordination, it is important to identify the key dates in which such coordination would be effective. Figure 1 below shows the CPP timelines.

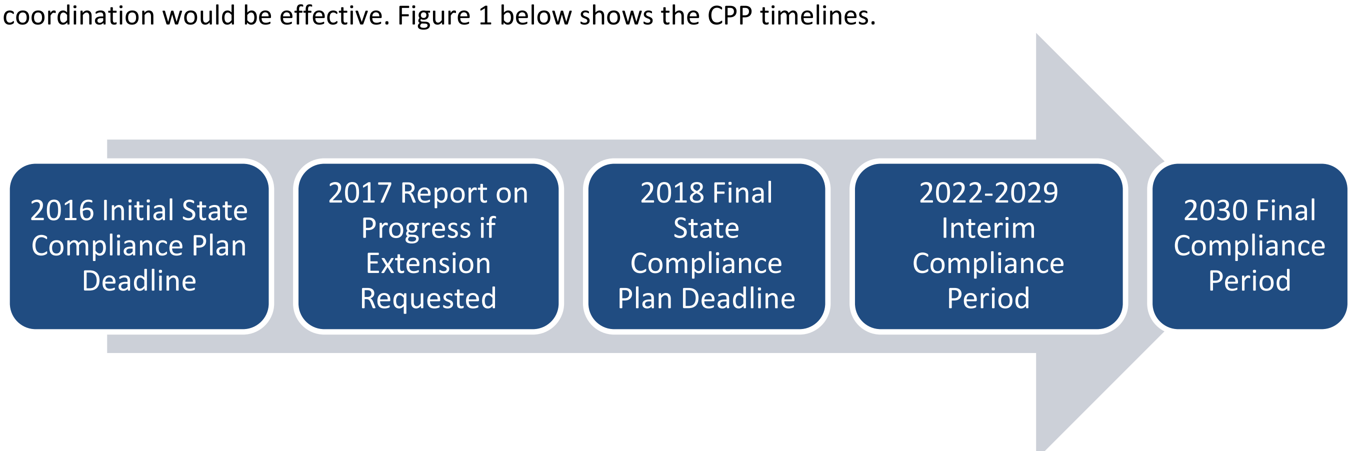


Figure 1: State Implementation Plan Timeline

For permitting and siting new generation and transmission, it is essential that electric planning entities work closely with states to ensure that the timing of both new infrastructure and retirement of existing infrastructure is supportive of system needs and compliant with environmental regulation.

The map below shows the major BPS assessment areas within North America.

NERC's reliability assessments are developed to inform industry, policy makers, and regulators and to aid NERC in achieving its mission—to assure the reliability of the North American BPS. For the purposes of these assessments, the BPS is divided into assessment areas shown above. NERC prepares independent seasonal and long-term assessments to examine the current and future reliability, adequacy, and security of the North American BPS.

ISO/RTO Model Coordination

Coordination between states and ISO/RTOs is an essential feature of certain electricity power markets. ISO/RTOs are entrusted by their members to operate the BPS in a reliable manner. While states generally do not directly operate the electric system, they are responsible for ensuring a reliable electric supply within their state.

The CPP does not change the need for states and ISO/RTOs to work collaboratively; however, it does highlight the need to enhance understanding of each other's roles and the coordination of common reliability objectives. The EPA has given air regulators authority to develop state implementation plans and recognized the need for these agencies to coordinate with ISO/RTOs.

The EPA specifically expects states to coordinate with ISO/RTOs to ensure consideration of reliability at three key points in plan development and implementation:

- During state implementation plan development process
- When verifying the need for Reliability Safety Valve (RSV)
- Before any modifications or revisions to a state plan

Vertically Integrated Utility Model Coordination

Coordination between states and vertically integrated utility organizations is important to successful deployment of state plans. Vertically integrated utilities are directly entrusted by the state utility commissions to develop and operate their assets in a manner that supports both reliability and appropriate consumer pricing. While state environmental and utility regulators do not directly operate the electric system, they have a responsibility to act on behalf of utility customers to facilitate both reliability and low cost of electricity within their states through obligations placed on vertically integrated utilities.

Regulatory Frameworks Applicable to Both Models

Both RTO/ISO and vertically integrated utility models actively implement or participate in regional transmission planning forums where issues that arise in transmission planning are resolved. Resolution of these transmission issues is critical to timely and reliable implementation of both generation and transmission asset changes necessary to implement the goals of the CPP.

State Coordination on Reliability Concerns

According to the EPA's final emissions guidelines, states that do not take reliability concerns into consideration when establishing standards of performance are not in compliance with section 111(d)(1)(B) of the Clean Air Act and therefore have not developed an approvable plan. The EPA ultimately desires states to develop plans that will result in a reliable grid unless a significant unforeseen issue arises. While the EPA does not require states to consult with ISO/RTOs or other planning organizations during implementation plan development, the transmission planning environment may be an effective way for states to satisfy the CPP requirement. ISO/RTOs as a normal course of business, but also at the request of states and stakeholders, regularly perform both operational and planning reliability assessments that can be incorporated in or relied on for a final state plan. The larger vertically integrated utilities also perform reliability assessments on a regular basis, including the development of integrated resource plans, which should also be considered in the final state plan.

In the event a state claims a new reliability concern due to some subsequent event, it is mandatory for the affected state to consult with the relevant planning entities to revise or modify its implementation plan. Before reviewing a state's request to revise its plan, the EPA requires the ISO/RTO or planning entity[4] to issue a statement accompanied by analysis confirming that there are no practicable alternative resolutions to the reliability risk asserted by the state on behalf of generation owner(s). This is a very high hurdle given the multiple market-based options provided in the final rule.

In the circumstance that the RSV is invoked, coordination between the state(s) and the planning entities becomes even more critical as there are specific deadlines identified in the final emissions guidelines for (1) reporting the reliability violation, (2) determining the extent and duration of the reliability violation, and (3) determining the need to continue operating units on a revised standard beyond 90 days. Failure of coordination between planning entities and states can lead to the RSV's not being approved or delays in approval of a revised state plan if needed. This result will create uncertainty in system operations and diminish reliability.

[4] Although not fully defined in the CPP, in areas where ISO/RTOs do not exist, NERC Regional Entities may be called upon to assist in assessing reliability.

CPP Considerations

Early collaboration and cooperation are the keys to successful CPP implementation coordination in a given state. In addition to FERC, public service commissions, and public utility boards, states also have energy offices and environmental agencies that collectively oversee the performance of utilities and asset owners. These organizations may have information that can enhance the understanding of state plan implementation teams. State environmental/air regulators are responsible for protecting the environment and public health by ensuring compliance with environmental laws.

The EPA gave states authority to develop implementation plans to ensure appropriate implementation of the CPP. For permitting and siting new generation and transmission, it is essential that electric planning entities work closely with states to ensure that the timing of both new infrastructure and retirement of existing infrastructure is consistent with system needs and compliant with environmental regulation.

The reliability-oriented outcomes of successful coordination include or result in:

- An adequate level of generation resources to reliably serve electric consumers;
- Adequate transmission infrastructure to reliably deliver the output of new generating resources to load;
- A resource mix that provides the Essential Reliability Services needed to continue the successful and reliable operation of the BPS; and
- Timely plan revisions that address a short-term reliability problem that is expected to be chronic and evolve into a longer-term problem.
- System resiliency whereby risk management paradigms are employed to ensure adequate resources and minimize interruptions of service during critical events.

Essential Reliability Services

Changes to electricity generation and use patterns may affect reliability, and the reliability of the electric grid must be maintained through additional engineering and implementation activities. The North American BPS is already transforming to a resource mix that uses less coal generation while integrating more natural gas, wind, solar, distributed generation, and demand response resources. The grid is also seeing a shift in the availability of nuclear generation. The power system may change further as microgrids, smart networks, and other advanced technologies continue to be deployed. The Clean Power Plan (CPP) will potentially hasten this transformation.

Essential reliability services are necessary to balance and maintain the electric grid and include voltage control, frequency support, and ramping capability. A recent NERC report[5] provides details on the value and importance of essential reliability services and identifies next steps.

While the reliability attributes and contributions of conventional generators are well documented, many of the new resources are capable of providing essential reliability services supporting frequency, ramping, and voltage, but may not be required to perform these functions today. During and after the transition from large generators (like coal plants) toward these newer resources, these reliability services will be required if reliability of the BPS is to be maintained. Proper planning and providing system operators with the ability to manage resources in real time will continue to be required to ensure that the appropriate levels of essential reliability services are available and that reliability is maintained as the resource mix evolves.

Whereas distinct market mechanisms and wholesale services are regulated by FERC, states plan for policies on resource mix and establishing Reserve Margin requirements. Therefore it is important to note that while states may not control policy around ERS, state resource decisions and planning around those decisions have ERS as a distinct factor. States also have the authority to approve interconnection standards and requirements, which establish the physical and performance capabilities of generators that are interconnected to the distribution system and/or behind the customer meter.

The Building Blocks of Reliability

Based on the analysis of geographic areas that are experiencing the greatest level of change in their types of resources, a number of measures and industry practices to monitor trends and prepare for the transition in resource mix have been identified. These recommendations consider both real-time operations and future planning to support frequency, ramping, and voltage of the system.

Frequency Response – The electric grid is designed to operate at a frequency of 60 hertz (Hz). Deviations from 60 Hz can have destructive effects on motors and equipment of all sizes

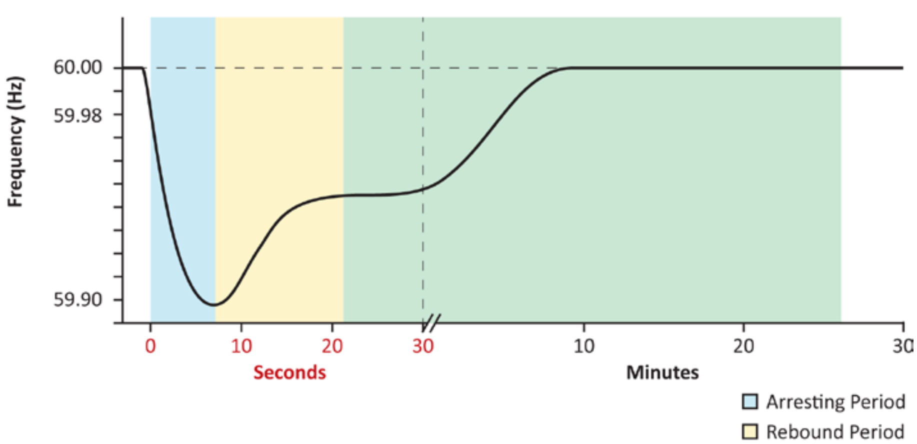


Figure 2: Frequency Response

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

and types. It is critical to maintain and restore frequency after a disturbance such as the loss of generation. As shown conceptually in Figure 2, frequency will immediately fall after such an event. This requires an instantaneous (inertial) response from some resources and a fast response from other resources to slow the rate of fall during the arresting period; a fast increase in power output during the rebound period to stabilize the frequency; and a more prolonged contribution of additional power to compensate for lost resources to ensure that system frequency transitions back to the normal level. For a further description of frequency response, please see the following video link: Frequency.

Ramping Capability – Adequate ramping capability (ability to match load and generation at all times) is necessary to maintain system frequency. Changes to the generation mix or the system operator's ability to adjust resource output can impact the ability of the operator to keep the system in balance. For a further description of ramping capability, please see the following video link: Ramping Capability.

Voltage Performance – Voltage must be controlled to protect system reliability and transfer power from generating sources to where it is needed to support both normal operations and following a disturbance. Voltage issues tend to be local in nature, such as in sub-areas of the transmission and distribution systems. Reactive power is needed to keep electricity flowing and maintain necessary voltage levels. The utility industry has been dealing with solutions for reactive power concerns for many decades and various technologies are commercially available.[6] For a further description of voltage performance, please see the following video link: Voltage Performance.

CPP Considerations

It is crucial to know how the power system performance may change in light of the operating characteristics resulting from a changing resource mix, what attributes can be expected from resources in the future, and how to make the transition to this future system in a reliable way. These considerations present both opportunities and challenges before and during the implementation of the CPP. Additional recommendations include:

- The NERC ERS report recommends that all new resources have voltage and frequency capabilities. Monitoring of the ERS measures, investigation of trends, and use of recommended industry practices will highlight aspects that could become reliability concerns if not addressed with suitable planning and engineering practices.
- DERs will increasingly impact the planning and operation of the grid. The NERC ERS report recommends further examination of the forecasting, visibility, controllability, and participation of DERs as an active part of the electric grid.

Analyses of changes are required for effective planning and provide system operators the flexibility to modify real-time operations to maintain the reliability of the grid. These recommendations will assist in understanding the implications of the changing resource mix and how the electric power industry can manage the evolution of the system in a reliable manner.

[6] Solutions used to support reactive power or short circuit strength include synchronous condensers, fixed capacity banks, switched capacity banks, and static VAR compensators.

Timing Considerations for Energy Infrastructure Development

Years of effort may be required when building new generating resources or transmission lines that are necessary to support reliability or compliance with the CPP. The lead times required and associated uncertainties for the planning, engineering, permitting, and construction of new generating resources, transmission facilities, and fuel infrastructure may challenge the reliability of the BPS based on when such activities are commenced and the complexity of the solution.

An analysis of industry planning and lead time experience is provided in the NERC CPP Phase I report.[7] For state implementation plans submitted and finalized from 2016 to 2018, approximately four to six years remain prior to the 2022 Clean Power Plan initial implementation date. Figure 3 illustrates the concern.

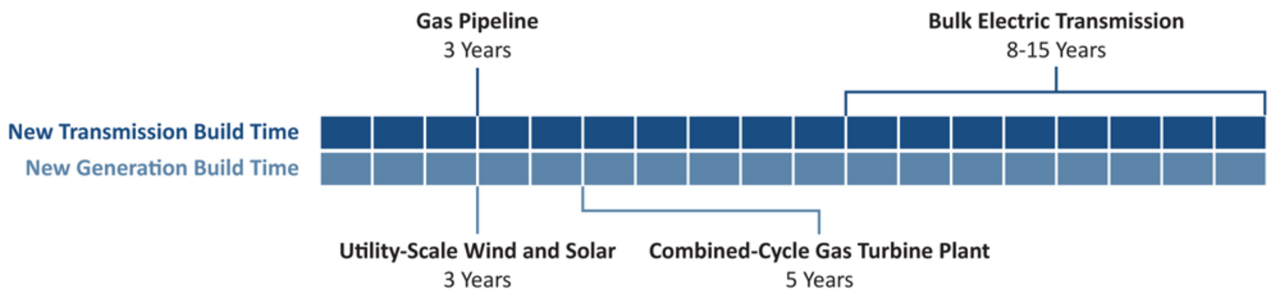


Figure 3: Infrastructure Timeline

Uncertainty in the timing of such resource decisions and the ability to construct the necessary energy infrastructure to implement those decisions stems from the following factors:

- The addition of new generating resources can take several years to permit and construct. There will be a range of time periods depending on the circumstances related to each project and the availability of construction crews and equipment.
- Changes to resources (such as retirements or new generation) can require a need for additional electric transmission infrastructure. Such transmission can require many years to permit and construct, typically longer than generation construction, and timing will depend on the facts and circumstances of each project.
- Where new or repowered generating resources are dependent on natural gas as a fuel, there will be a requirement for additional gas pipeline infrastructure. Depending on the location of the plant relative to interstate gas pipelines, plant-specific gas infrastructure will require several years to permit and construct.
- The resource decisions of neighboring states can also impact the transmission infrastructure required to maintain reliability within a given state.

In summary, generation resource decisions, including retirements, are not likely to be known by the time state plans are finalized. Furthermore, such resource decisions may require additional transmission and fuel infrastructure in order to be integrated reliably. The addition of new generation, fuel infrastructure, and transmission can all have significant lead times that could potentially impact successful implementation of a state plan.

[7] In NERC's Phase I CPP Report see Chapter 4 regarding the planning process and Chapter 5 regarding the lead time experience: http://www.nerc.com/pa/rapa/ra/reliability%20assessments%20dl/potential%20reliability%20impacts%20of%20epa's%20proposed%20clean%20power%20plan%20-%20phase%20i.pdf

CPP Considerations

State plan designers should work with appropriate stakeholders as they develop their plans to understand how decisions could potentially impact reliability, the need for additional energy infrastructure, and the effect on CPP compliance timelines. Outreach to ISO/RTOs or regional planning entities will be necessary. Generation and transmission development timelines may vary considerably when all supporting facilities, including gas pipelines where needed, are considered. Generation can be retired quickly; however, it will likely take years to build new electric transmission lines to reinforce the transmission system and construct new generators to address any reliability gaps.

Electricity Imports and Exports

In addition to other regulatory factors that affect the decision to operate individual generating units, a state's import and export options may further complicate the analysis of compliance strategies. In general, areas with a higher CO_2 reduction obligation may increase their imports of power to displace emissions, while areas with lower CO_2 reduction obligations or favorable zero-emissions resources may potentially increase exports. As compliance strategies are developed, decisions that change a state's available resources may impact future transfer capabilities. The dynamics of import and export capability along with the potential net changes as a result of CPP compliance suggest that additional collaboration between states may be needed to accurately account for potential changes in interstate transfers. For CPP implementation, it will be necessary to conduct coordinated assessments of transmission system impacts of neighboring systems, including the transfer capabilities of the nearby systems to account for these potential changes in imports and exports.

CPP Considerations

States should understand how changes in expected future transfer capabilities precipitated by multiple CPP compliance strategies could impact reliability. Additionally, states should work with stakeholders to understand how decisions could potentially impact reliability and the potential need for additional transmission infrastructure. For example, if a state intends to use resources from nearby states as part of its compliance strategy, it is important to assess the transmission capabilities to reliably deliver the power from those resources. Furthermore, modifications to the resource mix in a state's footprint can impact import and export capability. It is important to understand the transmission impacts of such decisions and the ability to reliably preserve transfer capability for import and export commitments as well as for emergency operations.

Change in Generator Cycling and Operations

Future compliance with the CPP may change the generators that are operated, when they run, and their dispatch levels. For example, increasing the use of gas-fired generation and reducing production from coal-fired resources is one driver of increased cycling. This is a strategy that states with diverse generation fleets (dispatching both coal-fired and natural-gas-fired generators) may consider to limit their overall emissions.

Historically, most coal-fired generators were designed as baseload units. If coal-gas cycling is considered as part of a state implementation plan under the CPP rule, coal-fired generation would be expected to operate seasonally, or even weekly, to serve peak demand needs while balancing environmental constraints with economic viability. A recent study by Electric Power Research Institute (EPRI) assessed the operational implications of cycling coal and gas units. The study found changes in operations of not only the baseload coal-fired unit but the entire plant in regard to fuel costs, plant operational goals, and increased preventive maintenance. Similar changes in operations were found for gas-fired combined-cycle plants that were converted for baseload power generation purposes.[8] In addition to reliability considerations for reduced operation, there will be direct impacts to fuel supplies and available manpower to operate the units.

The result will be reduced use of existing coal-fired generators, and they may operate for shorter time intervals or only to satisfy seasonal load. The result will be increased damage to generating units due to more frequent thermal cycling.[9,10] This is likely to increase maintenance costs and/or impact the performance of these units. Some coal plant operators faced with cycling operation may choose plant retirement instead of ongoing operation with higher operations and maintenance costs.

CPP Considerations

Identified below are key reliability considerations that would need to be accounted for if states were to consider coal cycling in state implementation plans:

- **Cycling of coal and gas plants**
  The CPP could potentially result in increased cycling of coal-fired units and increased capacity factors in natural-gas-fired units. This may represent a change in traditional operating characteristics of these units that should be accounted for as states develop their CPP plans.

- **Maintenance and forced outages**
  Increased cycling of coal resources and the subsequent increase in natural gas capacity factors can result in higher maintenance and an increase in forced outages.

- **Increased coordination between gas and electric system operators**
  A change in the operating characteristics of both coal and natural gas units can increase the need for coordination between gas and electric dispatch managers/operators to ensure gas supply is available when required to ensure reliability.

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8 "Future Perspectives in Operations: Managing Through a Changing Operating Regime" – EPRI, 2013 – Product ID: 3002001129.

9 Every time a power plant's state of operation changes (started, stopped, turned down, or ramped up), the boiler, steam lines, turbine, and auxiliary components go through substantial thermal changes. The material stresses that result from these more frequent operation changes escalate loss of useful life through fatigue and cumulative equipment damage. Cycling also increases failure rates and can result in a loss of reliability from increased plant forced outage rates. Ultimately, larger capital and maintenance costs to replace damaged components are more likely as a result of consistent cycling.

10 For more information on the effects of coal plant cycle see "Power Plant Cycling Costs", NREL April 2012 at: http://wind.nrel.gov/public/wwis/aptechfinalv2.pdf

Reserve Margin Levels with a Changing Generation Mix

Reserve Margin and capacity adequacy assessments play an important role in maintaining BPS reliability. Planning Reserve Margins, based on rigorous probabilistic analysis of the generation mix, provide a key signal of expected future reliability and guide decisions for building sufficient capacity to meet energy needs. Particularly during this transition, Reserve Margin targets and resource adequacy requirements must be calibrated with the resources that are on the system.

NERC uses a Planning Reserve Margin as a primary metric for resource adequacy assessments. For each assessment area, a forecast of resources is compared with the target value (the Reference Margin Level) to determine the Planning Reserve Margin. These values are developed through probabilistic and historical analyses to identify the level of resources that are needed to maintain the desired level of system reliability. Given a sufficient Reserve Margin, a system should be able to meet the projected electricity demand under normal weather circumstances, and also with a high degree of certainty that the system can tolerate generator outages and modest deviations from the annual demand forecast.[11]

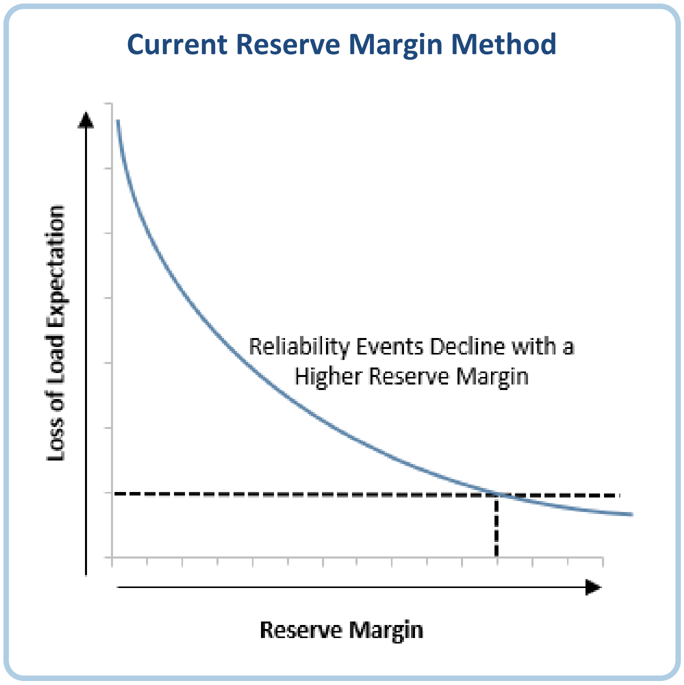

Figure 4: Reserve Margin Analysis

The Reserve Margin is essentially the difference between the available capacity and peak demand normalized by the peak demand, and projected Planning Reserve Margins show whether capacity additions are keeping up with demand growth. The measure is focused on peak conditions and the underlying assumption is that if the system can maintain reliability during the peak hour (the most severe demand hour), then the system can maintain reliability throughout the year. Figure 4 demonstrates the correlation between reserve margins and a loss of load expectation.

However, with an increase in VERs, DERs, and demand response, energy adequacy and the ability to serve demand across all hours of the year become the critical challenge for system planners. Constraints include water availability for hydro production, gas availability when pipelines are under maintenance or gas supply is limited by competing uses, solar and wind generation that depend on the availability of the sun and wind, and in the case of the CPP, a carbon constraint that will significantly limit the amount of fossil-fired generation. Off-peak hours and shoulder periods must also be considered for reliability, particularly when power output of many resources may be variable or have other operational limitations while other plants may be undergoing maintenance.

The Planning Reserve Margin metric does not sufficiently consider fuel availability, essential reliability services, and the concurrent interrelated failures that can be experienced during extreme conditions, as it assumes that generator fuel availability is not correlated with load levels or weather. Recent extreme weather events create an

[11] While the Planning Reserve Margin offers insight into the relative ability of a system to serve load based on existing and planned resources, this metric does not fully capture important reliability attributes essential for ensuring grid reliability. The Reserve Margin does not account for the various types of daily operating reserves that are needed (e.g., regulating reserves, spinning reserves, non-spinning reserves, and load-following reserves) to balance load and supply in real time and enable System Operators to quickly and reliably respond to a system contingency. This is the primary driver for NERC's essential reliability services initiatives.

increased number of forced outages due to fuel unavailability, particularly natural gas, all happening at the same time. Current Reserve Margin methods may understate these risks as most methods assume outages are randomly distributed. Similarly, for VERs like wind and solar energy, a method is used to adjust installed or seasonally rated capacity values with nameplate capacity derated for use in the Reserve Margin calculations. While methods that analyze years of detailed generation and load data can reflect the appropriate capacity values for all resources, simpler methods that are commonly in use today fail to fully evaluate the reliability contribution from these resources during extreme weather events.

The totality of these limitations and constraints compels the industry and regulators to consider additional measures for reliability and resource sufficiency. There is a need to supplement reliability assessments with probabilistic measures that account for potential energy deficiencies, operational risk assessments, and measures for essential reliability services.

CPP Considerations

Compliance with the CPP will accelerate an ongoing shift in the generation mix, with retirements of baseload generators or additions of VERs. In order for Reserve Margin analysis to continue providing value as a resource adequacy metric, additional consideration is needed regarding how planning entities develop their Reserve Margin levels. The forced outage rates of a generation fleet will be impacted both by changes in the generation mix and by changes in the way the current resources are used, such as from increased cycling of coal units. These impacts need to be assessed and incorporated as Reserve Margin metrics are enhanced, and they should be considered as we develop more sophisticated reliability planning methods.

If Reserve Margins decline, there may be less generation available to serve load under high-stress conditions. Tracking of emissions and the projections for year-end emissions goals are an additional constraint. For instance, in a year where there is an extreme increase in load due to weather, or even resurgence in the economy, the system will need to simultaneously satisfy the multiple objectives of reliable electric operations, year-end emissions goals, ERS requirements, and adequate reserves. The CPP implementation plan must allow the electric system to be carefully planned with these simultaneous objectives in mind.

Energy Efficiency

Energy efficiency (EE) plays an important role in the cost-effective operation of the electric system and provides sustained reductions throughout the year. While EE can be instrumental in deferring generation and/or transmission investment by reducing the peak load, most of the benefits of EE have traditionally been associated with lower energy consumption and energy cost.

The Final Clean Power Plan rule is based on three building blocks that according to the EPA represent the Best System of Emissions Reductions (BSER). While EE was not included as building block in the BSER, it may still play a prominent role in helping states achieve compliance with the CPP.

Contemporary Energy Efficiency Considerations

State and local policies, economic factors, local climates, and customer differentiation lead to very different EE adoption rates across the NERC Regions. As a result, utilities face different challenges for evaluating EE. Today, utilities and system planning entities are not all equally capable of incorporating EE in planning processes, specifically the load forecast.

The load forecast drives all planning functions from transmission reinforcements to determining the need for new generation. Traditional load forecasting models depended on a narrow set of weather factors and economic regression terms to forecast future electric consumption and peak demand. As communities, technology, and customer usage patterns evolve, planning entities have begun to adopt more sophisticated models to capture these changes for both transmission and distribution system planning. With the introduction of additional complexity coupled with uncertainty associated with energy efficiency and distributed generation, future electricity demand becomes more difficult to predict.

Future Energy Efficiency Considerations

Though the Clean Power Plan will regulate generators that predominantly are interconnected to the BPS, EE measures are generally deployed on the distribution system. There is a need for standardized evaluation, measurement, and verification (EM&V) to adequately account for EE in the load forecast.

Across the NERC Regions, utility systems have a wide range of fuel characteristics. Consequently, the emissions that would be displaced by EE can vary significantly by location, season and time-of-day. In an emissions constrained environment, accurate estimation of the load forecasts will be helpful for states as they consider allowance allocation methods that best support reliability objectives. For example, transmission and generation outages can be scheduled well in advance or very near to the operating period. For longer-term outages that overlap with compliance reporting periods, inefficient allocation methods can lead to operational reliability concerns.

CPP Considerations

States that identify EE as a primary tool to achieve emissions reductions should perform modeling to predict program performance expectations and address EM&V. Utilities and ISO/RTOs should establish a primary role in conducting this analysis or, at a minimum, verifying results through independent assessments. Standardized EE EM&V and adoption of best practices in load forecasting techniques are necessary for the effective use of EE to support CPP compliance.

Emissions Trading

The EPA has provided for the potential development of a trading system using Emission Rate Credits (ERCs) or allowances. State plan designers will have the ability to choose between using either a rate-based or mass-based state implementation plan. This choice can have consequences for trading, which in turn can impact resource decisions and associated reliability outcomes.

Emissions trading is not by itself a reliability issue; it is an economic one. However, since trading will not be permitted under the CPP between states using a rate-based approach and states using a mass-based approach, it is possible that resource options that might have been available through trading may not be available depending on state plan choices. As such, states should work with utilities in their respective states and neighboring states to assess the reliability implications of their choice between rate-based and mass-based options.

CPP Considerations

Trading in general promotes reliability by allowing resources needed for reliability to acquire an allowance or credit to run. With a broader compliance region, there will be a wider pool from which to acquire the allowance/credit. For states choosing a rate-based option, ERCs are only generated by qualifying generation or verified EE. For states choosing a mass-base option, the quantity of allowances is known for each compliance year. In addition, given the rules that restrict trading between mass-based and rate-based states, some resource options that might have otherwise been assumed to be available through trading could be unavailable due to another state's plan choice.

Reliability Safety Valve: Planning Considerations for States and Regions

The EPA has provided for a Reliability Safety Valve (RSV) to be used for catastrophic events. The RSV is intended to maintain reliability in the event of extraordinary or unanticipated events. It should be noted that states cannot rely on an RSV as part of their overall compliance strategies. Furthermore, only approved state plans will be able to trigger the RSV as EPA has proposed that the federal plan will not include the RSV. A memorandum between the EPA, the DOE, and FERC pledges that the three federal entities will to work together to monitor implementation, share information, and resolve difficulties.

At various points during the RSV process, states must coordinate with the relevant planning entity and report that coordination to the EPA. The RSV includes an initial period of up to 90 days during which reliability-critical-affected Electric Generating Units (EGUs) will not be required to meet the emission standard established under the state implementation plan, but rather will meet an alternative standard. While the initial 90-day period is in use, the emissions of the affected EGUs that exceed their obligations under the approved state plan will not be counted against the state's overall goal or emissions performance rate for affected EGUs.[12] Any emissions in excess of the applicable state goals or performance rates during the second 90-day period must be accounted for and offset.

CPP Considerations

The RSV is intended for catastrophic purposes only and as such should not be used as a planning tool to meet CPP requirements. It is important for states to understand how they might use the RSV in the case such an event would occur. At various points during the RSV process, states must coordinate with the relevant planning entity and report that coordination to the EPA. In the event a revised plan needs to be expedited for reliability reasons, the state must provide an analysis from the RTO/ISO or planning entity, the latter of which could include NERC or the Regional Entity.

[12] In addition, the emissions will not be counted as an exceedance that would otherwise trigger corrective measures under an emission standard plan type or an exceedance that would trigger the submission of a backstop plan under a state measures plan.

Conclusion

This report represents NERC's continuing efforts to identify what is necessary for reliably implementing the EPA's CPP rule. The intent of this report is to help guide state utility regulators, state environmental regulators, and state executive offices in their consideration of BPS reliability risks as they formulate their state plans to be submitted to the EPA.

The BPS continues to experience an unprecedented transformation in the resource mix that will be accelerated by the CPP. It is critical that states be mindful of and account for the reliability risks expressed in this report as they are developing their plans. NERC and the NERC Regional Entities are prepared to work with states as they address reliability implications of the CPP in their state implementation planning process.

Additionally, NERC is conducting an analysis of possible scenarios of the CPP final rule. These analyses will include a business-as-usual base case (reflecting conditions without the CPP) as well as other scenarios showing potential effects related to the CPP and how those outcomes might impact the reliability of the BPS. It is intended that system planners will be able to use this report as a framework to conduct more granular analyses around the CPP and the direct implications to their specific areas or regions of interest. The scenario report is expected to be released near the end of the first quarter of 2016.

Appendix A – North American Precedents: Regional Greenhouse Gas Initiative

The Clean Power Plan is not the first attempt within North America to address air emissions associated with electricity generation. Most relevant to the Clean Power Plan is that 10 states in the northeastern United States have implemented a CO_2 cap-and-trade program on new and existing electric generating units (EGUs) since 2009.[13] The EPA has noted that the success of the Regional Greenhouse Gas Initiative (RGGI) serves as a model of potential CPP implementation.

RGGI is a multistate effort to reduce CO_2 emissions from the electric power sector. Collectively, the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont (and previously New Jersey) agreed on an overall CO_2 emissions goal and apportioned allowable emissions to each state. The RGGI cap for 2015 was 88.7 million short tons of CO_2 per year, declining 2.5 percent each year from 2016 to 2020. Each state then issues an equivalent number of allowances, which represent the right to emit one ton of CO_2. RGGI states auction the vast majority of allowances, ensuring market liquidity and providing revenue to states.

EGUs in these states must hold an allowance—from any RGGI state—for each ton of CO_2 emissions. Thus, CO_2 becomes a variable cost that affected units incorporate into their bids to ISO-NE, NYISO, and PJM. Affected EGUs obtain allowances at quarterly auctions or in the secondary market, such as the Intercontinental Exchange (ICE) and NYMEX Green Exchange or via over-the-counter transactions.

RGGI compliance occurs in three-year control periods. Each RGGI-regulated power plant must submit CO_2 allowances equal to its CO_2 emissions at the end of each three-year control period. The first control period began on January 1, 2009.

Notably, the RGGI states achieved a reduction in power sector CO_2 emissions of over 40 percent since 2005, while their economies grew eight percent (adjusted for inflation). RGGI neither required nor resulted in the elimination of coal, but did ensure that emissions reductions occurred where they were most cost-effective. Where fossil fuel generation is cost-effective, it still occurs. For example, CO_2 emissions in Rhode Island actually increased over the beginning of the RGGI period due to the increased dispatch of a new, highly efficient NGCC plant. However, because higher-emitting and less-efficient generation reduced operation, total emissions decreased region-wide. This flexibility allowed emissions reductions to happen wherever they were more cost-effective.

[13] New Jersey left RGGI after the first compliance period (2009-2011).

Appendix B – North American Precedents: Ontario's Experience Phasing Out Coal-Fired Generation

A Bold Promise

In 2003 the government of Ontario, Canada's largest province, declared that it would eliminate coal-fired generation in the province by the end of 2007. Fueled by growing concerns over health and environmental costs of coal-fired generation, the phase-out had broad public and political support. At the time about 25 percent of the province's electrical energy and capacity was provided by five government-owned coal-fired generating stations. The 2007 coal phase-out objective proved too ambitious if a reliable supply was to be ensured. However, in early 2014 the last coal-fired generator was shut down and emissions from electricity generation were drastically reduced. Thus, Ontario did not achieve the initial politically driven deadline, but did phase out coal entirely in just over a decade while maintaining reliability. As the CPP is much less ambitious, the Ontario experience can provide an extreme test case of reliability concerns, including the provisions of essential reliability services and other attributes provided by traditional baseload (coal and nuclear).

The Plan

To achieve its ambitious objective, the government developed a broad-based approach that included the following components:

- refurbish previously shut down nuclear reactors
- build new gas-fired generators
- build new renewable generators
- substantially increase investment in conservation and demand management (CDM) programs

The goal was to have a sufficient amount of additional generation and sufficient savings from CDM to complete the coal phase-out within four years.

The Challenges

Replacing the coal-fired generators meant much more than just replacing their electrical energy. The network had been designed and built with the location and capabilities of these plants in mind. The coal generators were flexible units that provided several services that are essential to the reliable operation of a power system, including:

- capability to ramp output up and down to follow changing electric demand and to keep power transfers within reliable limits
- voltage support to maintain network stability
- frequency response to maintain balance in supply and demand
- operating reserve to quickly replace a sudden generator loss
- black-start capability to restore the system after a blackout

Most of these services were replaced by services from flexible gas-fired generators.

Location Matters

Several of these essential reliability services were quite dependent on the location of replacement generation. Extensive studies by the system operator determined that to shut down the coal plants, particularly the large

4,000 MW plant on the north shore of Lake Erie, about 2,500 MW of the replacement gas-fired generation would have to be located in the Greater Toronto Area where almost half the people in the province live.

The first competitive procurement for 2,500 MW of gas-fired generation succeeded in acquiring the needed capacity and flexibility but it was not located within the area necessary to support reliability without the coal plants. Subsequent targeted procurement rounds were required. Given the growing realization that contracting and getting development approvals was taking longer than anticipated, the target date for coal closure was extended to 2009.

Planning is Dynamic

The first coal plant, a 1,200 MW plant close to Toronto, was closed on schedule in 2005. However, this first closure highlighted a phenomenon that had been developing throughout the decade.

Demand had been increasing rapidly, particularly in the summer, as the province moved from having its highest demands due to winter heating to having higher demands in the summer due to cooling. In 2006, an extensive review of planning assumptions concluded that much more generating capacity was required than had been previously assumed in order to meet reliability requirements.

The 2009 shutdown date was abandoned and the government requested the provincial power authority to develop a comprehensive plan that would lead to coal closure as soon as it could be done reliably. Based on advice from the industry, the government passed legislation in 2007 requiring generation from coal to end in 2014. As new generation came on-line and was demonstrated to be reliable, the coal units were phased out in a controlled manner over several years. The two smallest stations were converted to biomass fuel.

These changes in plans should not be surprising. Over the course of 10 years between declaration and shutdown there were many changes in technology, policy, planning assumptions, economic conditions, fuel prices, etc. There was not just one plan to achieve coal shutdown; there were many iterations to keep pace with changing conditions. This should be expected with any long-term initiative.

Ensuring Reliable Performance

A key consideration throughout the transition was to always have enough supply and delivery capability to meet reliability standards. This included the reliable delivery of gas. An important requirement for the new gas generators was to have firm gas contracts back to a liquid hub. This enabled the necessary gas pipelines to be financed and built to ensure the plants would have gas to operate, even in extreme conditions.

Shutting the coal plants was dependent on the performance of the new gas plants and the completely refurbished nuclear units; there was little operating experience in Ontario with either. There was a need to ensure they could perform as claimed and to understand any limitations through both cold and hot weather when they would be needed most. Extensive testing was undertaken to validate that the generators could meet the capabilities required to connect to the system. Even so, a requirement was established for the new generators to demonstrate reliable performance through two peak seasons before they would be considered reliable enough to replace coal. This was a rather simple but important test and was accepted as a prudent requirement despite lengthening the time to achieve the coal shutdown objective.

Flexibility through Gas/Electric Integration

The coal plants had been very flexible plants with low minimum load points, good ramping capability, known reliability, and the ability to be used for either baseload or peaking operation. Maintaining enough flexibility to reliably operate the system during and after the transition was an important consideration.

Throughout the transition, the province's energy regulator was proactive on a number of fronts, but one of the most important things it undertook was a detailed review of the services needed to support new gas generators. Through this process, the pipeline owners and generators developed a new suite of natural gas power services. One of these was a multi-nomination service (generators could nominate gas to their plants up to 13 times per day as compared to the industry standard of four times per day). Another was a new upstream and downstream storage balancing service to provide flexibility for generators to call on gas from storage to meet quick ramp requirements as well as to re-inject gas back to storage if the system operator required them to back off production. These practices to integrate gas and electric markets are industry leading and have worked very well.

Transmission – The Critical Link

Three of the coal-fired generators were large plants, and the transmission system had been developed over the previous decades in an integrated manner, linking these stations to the large nuclear plants and load centers. With the planned replacement of the large coal plants by smaller gas plants at many different locations, all of the historical patterns of power flow on the system changed. Significant investment was required in transmission and station equipment in order to maintain or improve transfer capability, permit higher short circuit levels, provide voltage support, increase import capability, connect new generators, and deliver the new generation to market. Planning and implementing these changes was complex and sometimes lengthy. Some changes, like the construction of a new 110-mile double-circuit 500 KV transmission line, took tremendous effort and many years to gain the necessary approvals and complete construction even though it was constructed almost entirely along an existing right-of-way. Figure 5 shows the investment that Ontario made in transmission between 2005 and 2014.

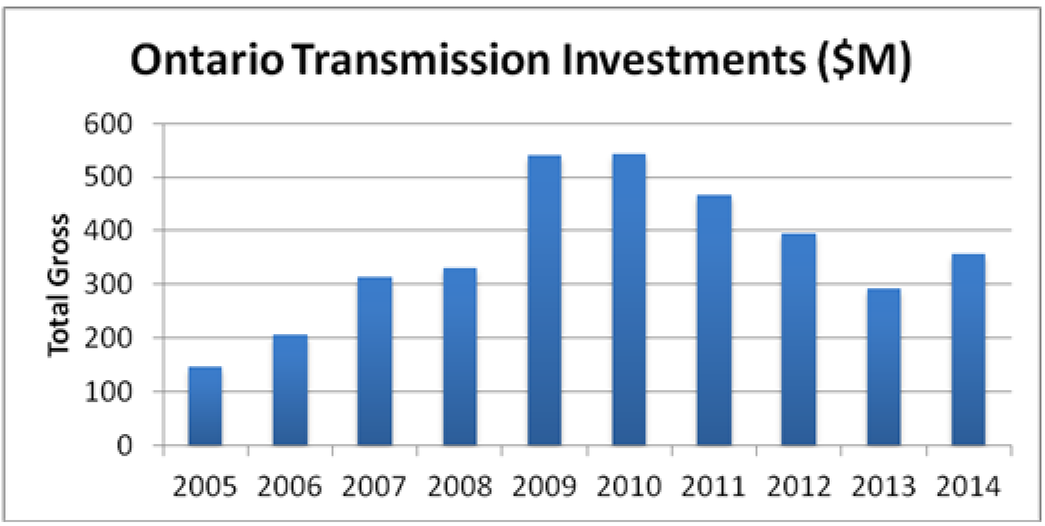

Figure 5: Ontario Transmission Investments

Consumers Have an Impact

An important contributor to reliably shutting down the coal plants was consumers using electricity more efficiently and reducing their use at peak times. A number of programs, standards, and incentives were launched, tailored for residential, commercial, and industrial customers. Since 2005 the wholesale demand for electricity has fallen by about 10 percent. While a good portion of this is due to economic factors and to solar generation connected to the distribution system, conservation efforts had reduced consumption by almost 10 TWh by the end of 2014.

Environmental Objectives Achieved

While reduction of greenhouse gas emissions was not the initial driving force for coal shutdown, it may be one of its most important achievements. Electricity sector emissions were cut in half and the province's overall GHG emissions were reduced by about 17 percent, allowing Ontario to meet its 2014 targets.

Even more dramatic has been the reduction in emissions of NOx, SOx and particulates. Even though the initial timeline for coal shutdown was extended, the emissions reduction was almost complete by 2011 even though the coal plants were still open for reliability reasons.

What Was Learned

Ontario's experience in reliably shutting down its coal plants demonstrated a number of important considerations that are likely to apply to any jurisdiction looking to significantly reduce the carbon intensity of their electric systems:

- a realistic and flexible plan, reviewed and updated frequently
- early attention to essential reliability services and transmission capability
- demonstrated performance of new supply
- a long-term focus on demand reduction and management
- flexibility in gas delivery arrangements and incentives for gas infrastructure

Ontario's experience also demonstrates that with focused objectives, flexible planning, and political persistence, transforming a power system to reduce its carbon emissions is achievable while maintaining reliability. Figure 6 demonstrates the changes in Ontario's installed capacity between 2005 and 2015.

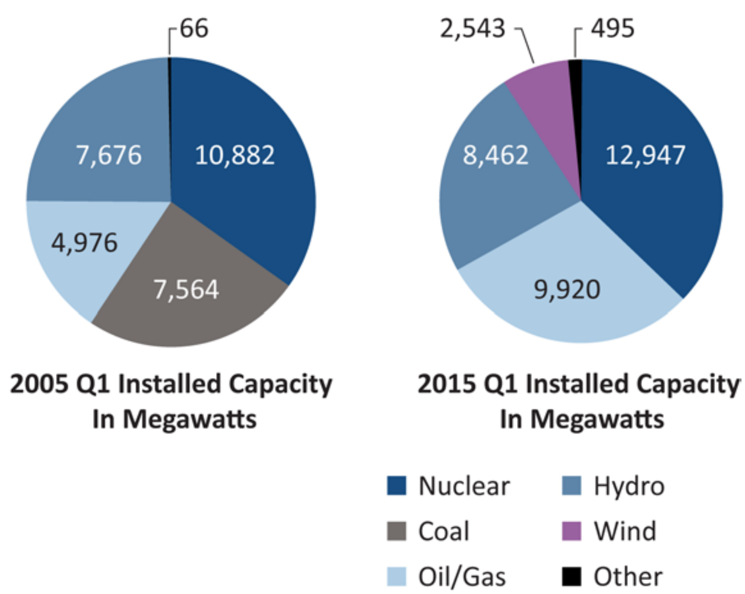

Figure 6: Ontario Capacity

Appendix C – European Precedents: Europe's Institutional Learning from Integrating Renewable Generation

For some years, portions of Europe have been pursuing a renewables-based solution to their environmental issues. The experience in Europe, although different from the CPP, can also provide guidance on how to address reliability concerns, including the provision of essential reliability services and other operational and design changes.

November 2006 Disturbance

The Europe-wide disturbance in November of 2006 revealed operational, legal, and regulatory gaps in Europe's electricity system management organizational structures. At the time, the operational security rules of the interconnected electricity network were not embedded within a Europe-wide operational and legal framework. That framework depended on voluntary measures mostly to be taken by the transmission service providers. The interconnected electricity networks of Europe ultimately found that it required a legally binding framework based on compliance monitoring and collaboration.

The event occurred when through normal operations surrounding a planned outage in November of 2006, a major disturbance was triggered and resulted in a series of cascading transmission line trips starting in Germany. The cascading effect continued south and finally resulted in a separation of the European network[14] into three sub-grids: western, southeastern, and northeastern areas.

The event is unique in the history of the European transmission system. According to the European Regulators' Group for Electricity and Gas (ERGEG) report,[15] more than 15 million households were disconnected and it appears that the event could easily have led to more serious blackouts in some parts of the European system. This event was not triggered by technical failures or external events (like extreme weather conditions).

The countries in the western area were Spain, Portugal, France, Italy, Belgium, Luxemburg, the Netherlands, Switzerland, and Slovenia, as well as parts of Croatia, Austria, and Germany. The power deficiency of about 9,000 MW led to a frequency drop to about 49 Hz (on a nominally 50 Hz system). This drop in frequency was stopped by automatic load shedding and by tripping pumping storage units.

The countries in the southeastern area were the former Yugoslav Republic of Macedonia, Montenegro, Greece, Bosnia and Herzegovina, Serbia, Albania, Bulgaria, and Romania, as well as parts of Croatia and Hungary. In this area, there was a smaller deficiency of power, which led to a frequency drop to about 49.7 Hz. These countries were not seriously affected by the disturbance.

The countries in the northeastern area were Czech Republic, Poland, Slovakia, and Ukraine, and parts of Hungary, Austria, and Germany. This area encountered a large surplus of generation. The frequency peaked at 51.4 Hz. The western and eastern areas were only reconnected after several unsuccessful attempts.

Findings

Generation from renewable energy sources, particularly wind generation, was found to be of special concern in the November 2006 European disturbance. At certain national levels, incentives had been introduced to increase generation from renewable sources. When decentralized or dispersed generation began to represent a significant

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[14] The original report on the event was written by UCTE. On December 19, 2008, in Brussels, ENTSO-E was formed by 42 TSOs as a successor to six regional associations of the electricity transmission system operators. ENTSO-E became operational on July 1, 2009. The former associations ETSO, ATSOI, UKTSOA, NORDEL, UCTE and BALTSO became a part of the ENTSO-E. website: https://www.entsoe.eu

[15] ERGEG Report Link: http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER PAPERS /Electricity/2007/E06-BAG-01-06_Blackout-FinalReport_2007-02-06.pdf

part of the generation resources, it was found that it is necessary to have these generators participate in the security protocols of the transmission network. As the European disturbance demonstrated, it becomes more and more important that smaller and/or decentralized generators become part of the system security. Information and operating protocol for these generators, including procedures for automatic tripping and coordinated reconnection, must be formulated in a way that guarantees system security and enables transmission system operators to control the system.

The identified need[16] was for detailed and specific obligations to be placed on transmission service providers in relation to the coordinated operation of the electric power networks across the European Internal Energy Market and to provide for information exchange between transmission service providers.

It was also found that the amounts of load-shedding capability during the disturbance differed from one transmission service provider to another. In many countries the first step of load shedding was activated when the frequency dropped below 49 Hz. In some countries not only the frequency but also its derivative (rate of frequency change) is used to define the amount of load to be shed at a given frequency level. The coordination of various load-shedding plans was paramount.

The analysis of the incident also showed that country-specific operating rules were not consistent at the European level. Emergency and restoration plans had been locally developed from to ensure as far as possible the secure operation of each power system in emergency or critical conditions. However, the local approaches did not incorporate pan-European issues, and even if they are appropriate at the local and national level, they did not fully consider how they must work together. The disturbance in November 2006 demonstrated that the European interconnected power systems are deeply interdependent and, consequently, emergency measures and the restoration phase must be coordinated.

Since the time of the event in 2006, Europe has been engaged in a program of adapting its rules, policies, and procedures[17] to better manage and coordinate the planning, design, and operation by generation owners and transmission system operators.

What Was Learned

Europe's experience in adapting to renewable dispersed generation demonstrated the need for orderly planning in making a major resource transition, such as directing attention to:

- The operational aspects and limitations of dispersed generation, for which the system operator may not have the same level of visibility and control as with utility-scale power plants
- The integration of legal and operational structures, taking into account the reality of the electric system operations across multiple political jurisdictions
- Services for maintaining reliability, such as frequency control, load shedding and black-start coordination
- The need for operational control and situational awareness between transmission service providers and generators

Europe's experience demonstrates that with focused objectives, flexible planning, sufficient time, and sufficient infrastructure investment, transforming a power system to reduce its carbon emissions is achievable while maintaining reliability.

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[16] ENTSO-E Report link: https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/RG_SOC_CE/130322_DISPERSED_GENERATION_final_report.pdf

[17] For an example of reliability centric policy recommendations in Europe see ENTSO-E paper: Dispersed Generation Impact on Continental Europe Region Security at: https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/150113_ENTSO-E_Position_Paper_Dispersed_Generation_Impact_on_CE_Security.pdf

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