NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Potential Reliability Impacts of EPA's Proposed Clean Power Plan

Phase I

April 2015

RELIABILITY | ACCOUNTABILITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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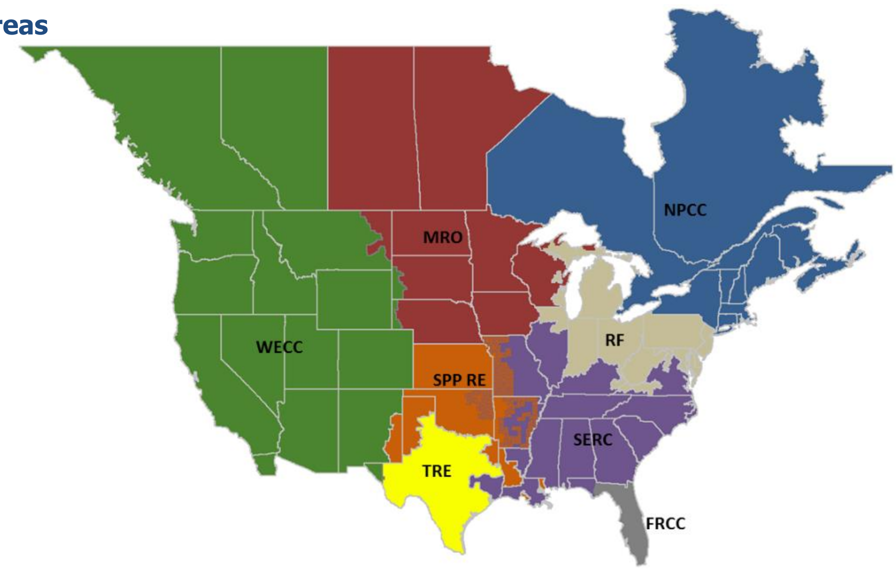
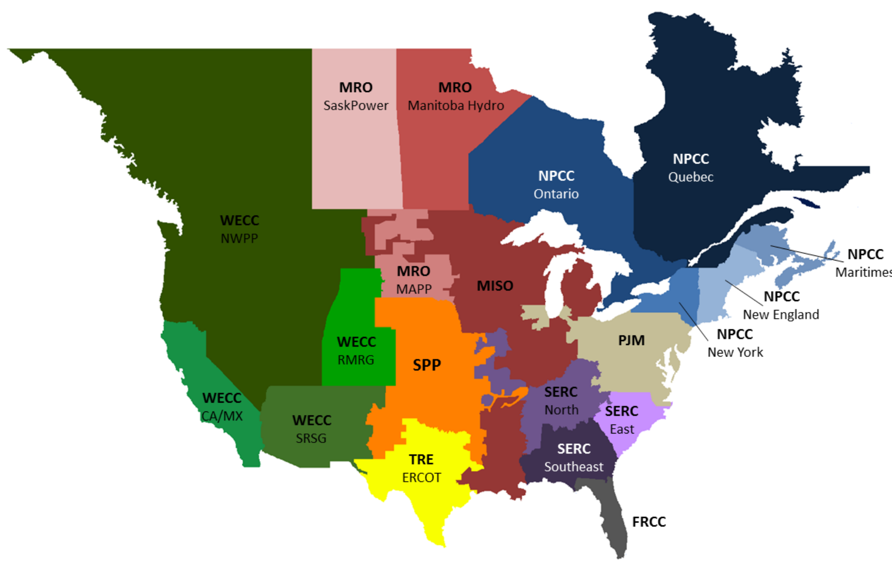
Preface

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.

NERC Regions and Assessment Areas

FRCC – Florida Reliability Coordinating Council	
	FRCC[1]
MRO – Midwest Reliability Organization	
	MISO[2]
	MRO-Manitoba Hydro
	MRO-MAPP
	MRO-SaskPower
NPCC – Northeast Power Coordinating Council	
	NPCC-Maritimes
	NPCC-New England
	NPCC-New York
	NPCC-Ontario
	NPCC-Québec
RF – ReliabilityFirst	
	PJM[3]
SERC – SERC Reliability Corporation	
	SERC-East
	SERC-North
	SERC-Southeast
SPP RE – Southwest Power Pool Regional Entity	
	SPP
TRE – Texas Reliability Entity	
	TRE-ERCOT
WECC – Western Electricity Coordinating Council	
	WECC-CA/MX
	WECC-NWPP
	WECC-RMRG
	WECC-SRSG





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.

[1] FRCC Region and Assessment Area boundaries are the same.

[2] The MISO footprint is primarily located in the MRO Region, with smaller portions in the SERC and RF Regions. For NERC's assessments, the MRO Region oversees the collection of data and information from MISO.

[3] The PJM footprint is primarily located in the RF Region, with smaller portions in the SERC Region. For NERC's assessments, the RF Region oversees the collection of data and information from PJM.

The North American Electric Reliability Corporation

Atlanta
3353 Peachtree Road NE, Suite 600 – North Tower
Atlanta, GA 30326
404-446-2560

Washington, D.C.
1325 G Street NW, Suite 600
Washington, DC 20005
202-400-3000

Questions

Please direct inquiries to NERC staff (assessments@nerc.net).

NERC Reliability Assessment Staff

Name	Position
Mark G. Lauby	Senior Vice President and Chief Reliability Officer
Thomas C. Burgess	Vice President and Director, Reliability Assessment and Performance Analysis
John N. Moura	Director, Reliability Assessment
Thomas H. Coleman	Director, Reliability Assessment
Ganesh Velummylum	Senior Manager, Reliability Assessment
Noha Abdel-Karim	Senior Engineer, Reliability Assessment
Elliott J. Nethercutt	Senior Technical Advisor, Reliability Assessment
David A. Calderon	Engineer, Reliability Assessment
Michelle Marx	Executive Assistant, Reliability Assessment and Performance Analysis
Amir Najafzadeh	Engineer, Reliability Assessment

Executive Summary

The Environmental Protection Agency (EPA) issued its proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units* on June 2, 2014, commonly referred to as the proposed Clean Power Plan (CPP). The proposed rule is issued under Section 111(d) of the Clean Air Act and establishes limits on CO_2 emissions for existing electric generation facilities. The proposed rule is currently anticipated to be finalized during summer 2015.

In its role as the Electric Reliability Organization in the United States, NERC has responsibility under Section 215 of the Federal Power Act to conduct periodic assessments of the reliability and adequacy of the nation's bulk power system (BPS)—the high-voltage transmission and generation system (as opposed to local distribution facilities). NERC's single focus is BPS reliability. NERC fulfills its responsibility in the public interest through conservative analyses and assessments that highlight reliability risks resulting from various possible future circumstances, given the severe consequences of an operationally unreliable or inadequate BPS for public health, safety and well-being, and our nation's economy and security.

On August 14, 2014, NERC's Board of Trustees directed NERC staff to develop a series of special reliability assessments to examine the potential risks to reliability that may arise from the implementation of the CPP rule and potentially accelerate the transformation of the resource mix in North America. NERC began development of this series of reports with its *Initial Reliability Review*,[4] published in November 2014, which examined the approach outlined in the proposed CPP and provided a high-level view of potential reliability risks.

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 BPS. Reliability assessments conducted while the EPA is finalizing the CPP can inform regulators, state officials, public utility commissioners, electric industry leaders, and other stakeholders of potential resource adequacy concerns, impacts to system characteristics (such as the straining of essential reliability services (ERSs)), and areas that may require transmission enhancements to ensure reliability.

This report is NERC's Phase I special assessment. It provides an analysis of scenarios and identifies the potential risks to reliability resulting from the resource transformation called for in the proposed CPP. This assessment and its findings do *not*: (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; (5) represent a final and conclusive reliability assessment; or (6) represent an actual system expansion plan.

NERC's Phase I assessment consists of a three-part analysis: (1) a scenario and sensitivity analysis driven by gas prices and state or regional implementation approaches to identify resource adequacy and the range of potential timelines associated with reliability reinforcement needed to meet CPP requirements; (2) a transmission adequacy analysis to determine a comparable range of transmission needs along with lead times required to build that transmission (natural gas pipeline reinforcements are also examined); and (3) summaries of existing studies by NERC reliability authorities (such as Reliability Coordinators, Transmission Planners and Operators, and Regional Reliability Organizations) related to the potential impacts of the CPP rule, with a focus on the relevant reliability impacts. NERC leveraged key information from these studies to identify cumulative impacts on a region-wide or interconnection-wide basis. Throughout this special assessment, a stakeholder advisory group formed by the NERC Planning Committee provided advice, input, and vetting of the underlying assumptions and publicly available data.

[4] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf.

Goals and Objectives

The goals and objectives of this assessment are to:

- Provide a resource and transmission adequacy evaluation given a number of potential scenarios that are driven by gas prices and state (as well as potential regional) implementation plans using different models to understand possible outcomes.
- Identify potential reliability risks and implications resulting from the projected resource mix changes to ERS characteristics, the increase in variable resources, the concentration of resources by fuel type (especially natural gas), the impacts on transmission requirements due to increased and potentially large power transfers, and other reliability characteristics, including Regional Entity planning reserve margins.
- Determine potential lead-time constraints associated with the electric and gas infrastructure enhancements needed to support the implementation of the proposed CPP.
- Assess industry analysis and studies from NERC reliability authorities (such as Transmission Planners and Operators and Reliability and Planning Coordinators) to determine if unique reliability issues may occur as a result of implementing the CPP requirements.
- Provide an independent assessment of reliability that informs policy discussions on risks to BPS reliability and related emerging issues.

Qualification

Significant uncertainty remains in the parameters of the final CPP rule, including compliance timeline flexibility; CO_2 targets and target calculation modifications; determination of whether groups of states (in addition to the Regional Greenhouse Gas Initiative (RGGI) states[5]) are able to coordinate to develop timely regional plans; details and coordination of the specific state implementation plans; federal model implementation plans or regional implementation plans; impacts of state selection of mass-based or rate-based limits; inclusion of regulatory reliability assurance mechanisms within the rule, etc. NERC recognizes that changes to any one of these parameters will have an effect on the analysis and results presented herein. As these uncertainties are resolved, further reliability impact analyses and assessments will be necessary to assess potential reliability implications.

Notably, the approach to formulate internally consistent assumptions, which are then formed into key scenarios, is designed to provide benchmarks and guidance about potential reliability implications during the implementation of the CPP rule. The model results illustrate potential scenarios and outcomes at a specific point in time based on input assumptions also applicable to a specific point in time. Therefore, the results are representative of a range of potential outcomes used to assess potential reliability impacts, but may not be indicative of what will necessarily happen as other modeling based on different decisions or changes to the proposed rule would alter the results.

NERC's modeling is designed to mathematically solve for lowest cost options. It was conducted with the premise that new utility-scale generation will be constructed to replace existing generation and meet electricity demand in the future. From NERC's perspective, the path to achieve the significant reductions in CO_2 emissions is through resource mix changes on the BPS. NERC's modeling is a conservative approach that does not rely on new technologies that are not yet widely integrated into the BPS or major changes in consumer choices and behaviors; however, NERC recognizes that significant additional conservation and distributed generation would have an impact on the results.

[5] Regional Greenhouse Gas Initiative: http://www.rggi.org/ (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont).

Assessment Approach

NERC focused on providing insight and guidance about potential reliability aspects from implementing the proposed CPP and specifically did not assess effectiveness, desirability, or optimal alternative CO_2 reduction methods. NERC's role is to evaluate the composite framework of plans and implementation changes that can potentially impact the BPS, using technically sound long-term, seasonal, and special reliability assessments and known parameters, assumptions, scenarios, engineering judgment, and practicality based on historical performance. For its resource adequacy analysis, NERC used two generator dispatch models: AURORAxmp and IPM.[6] For its transmission adequacy analysis, NERC used the static power flow models for the Eastern and Western Interconnections.

NERC retained three consultants to employ resources and transmission planning models to develop scenario results based on NERC's input assumptions. The findings and conclusions are based on the independent analysis of NERC's Reliability Assessment and Performance Analysis staff.

Key Findings

A transformative shift in resource use (or energy) leads to the need for transmission and gas infrastructure reinforcements, which will require additional time beyond currently proposed targets. This transformative change in the reliability characteristics of the resources supplying bulk power electricity places much greater emphasis on the need for adequate ERSs to be in place. The following key findings are components of NERC's overall assessment:

1. **Consistent with NERC's *Initial Reliability Review*, the proposed CPP is expected to accelerate a fundamental change in electricity generation mix in the United States and transform grid-level reliability services, diversity, and flexibility.**
   The anticipated changes in the generation mix and modified dispatch of resources driven by the proposed CPP will require comprehensive reliability analysis to identify grid-level reliability needs to accommodate the resource mix and flexibility requirements. Generating resource changes that are already underway would be accelerated by the implementation of the CPP and are prompting the need for much greater understanding of the ERSs (e.g., frequency response, voltage support, and ramping capability) needed to support BPS reliability. Implementation of the CPP would accelerate an ongoing fundamental shift in the generation resource mix toward greater use of gas and renewables, which presents reliability challenges as new resources have different ERS characteristics than the current generation fleet. For example, the reliability characteristics of a synchronous coal-fired steam turbine vary greatly from those of asynchronous, inverter-based machines.

   Importantly, this transformation introduces changes to operations and expected behaviors of the system.

   Finally, extensive power system studies and planning analysis need to occur to address expected changes in power flows and large multi-regional transfers. The power flow changes represented in NERC's analysis demonstrate the continued evolution of resource deployment and use of renewable and natural gas generation. Over the next several years, these resource changes will require more transmission to integrate the new resources, meet increasing electricity demand, and enable new exports and imports to accommodate a new resource mix. Consistent with NERC's conclusion in its overall assessments, power flow changes represent a significant planning and operational challenge, and sufficient time and coordination is needed to determine region-specific solutions.

2. **Industry needs more time to develop coordinated plans to address shifts in generation and corresponding transmission reinforcements to address proposed CPP CO_2 interim and other emission targets.**

[6] For further information on the AURORAxmp and IPM models please see Appendix A.

NERC's evaluations of the potential reliability implications of the proposed CPP and associated implementation plans by state or regional groups have identified fundamental changes in both the electric generation mix and corresponding transmission and gas pipeline infrastructure needed to accommodate these changes. Multi-regional and entity coordination is necessary to accommodate the long lead times for electric infrastructure and to ensure reliability during the implementation periods. A coordinated process not only ensures that stakeholders and consumers are provided sufficient time to review and respond to changes to the electricity grid, but it would also take into consideration NERC's mandatory Reliability Standards and FERC orders on operation and planning coordination (such as FERC Order 1000[7]).

Geographic and resource diversity and a complex regulatory environment present challenges to the long-term development of electric power infrastructure. The time required for new facilities to be developed and placed in service may likely exceed the CPP's proposed compliance targets. Because the industry will be implementing plans simultaneously, it is uncertain whether adequate equipment (e.g., generators, solar panels, wind facilities, transformers, and conductors) and resources (e.g., engineering, procurement, and construction) will be available to support those plans.

The interim target date within the EPA's CPP proposal requires notable reductions of CO_2 (approximately 80 percent of the total reductions) by 2020. It is likely that infrastructure to support the required interim reduction in CO_2 emissions at this pace will not be in service by 2020 for the following reasons:

> **Generation:** Between 2015 and 2020, over 33.5 GW of generation capacity (e.g., coal, oil, gas, and nuclear) is expected to retire, based on NERC's Reference Case from the *2014 Long-Term Reliability Assessment* (2014LTRA). An additional 7 GW is expected to retire between 2021 and 2025. In NERC's modeling of the CPP, State and Regional Cases yielded approximately 43 GW and 41 GW of retirements, respectively, between 2016 and 2020. Between 2020 and 2030, State and Regional Cases yielded an additional 42 GW and 44 GW of retirements, respectively. While replacement capacity may be able to repower coal to gas generation, others will require greenfield development, which on average will take between four and five years. From a Regional Entity perspective, areas with the greatest amount of resource retirements are ERCOT, SPP, NPCC, and MISO, with approximately 10, 7, 11, and 9 GW of retirements, respectively, between 2016 and 2020. Approximately 35 GW of non-hydro renewable energy (i.e., mostly wind and solar) is added due to the proposed CPP in all scenario results, in addition to planned variable energy resources (VERs).
>
> **Transmission:** Based on NERC's analysis, transmission-deficient areas have been identified. On average, transmission projects require between six and 15 years to engineer, site, permit, and construct, depending highly on the geography, length, and voltage class. From a Regional Entity perspective, areas needing the most transmission reinforcements are located in RF, NPCC, and the southwest area of WECC. As part of NERC's CPP Phase I study, NERC requested information from industry on new generation and transmission facility construction lead times. The results represent perspectives from 110 different transmission and generation companies on timing requirements for additional new transmission and generation capacity.

3. **Implementation plans may change the use of the remaining coal-fired generating fleet from baseload to seasonal peaking, potentially eroding plant economics and operating feasibility.**
A significant finding of the analysis points to an expected shift of existing coal-fired generation from baseload to seasonal peaking operations. According to NERC's modeling analysis, between 14 and 22 GW of coal generation resources remain online through 2030; however, these units are considered at risk of retiring due to the plant economics associated with operating the units infrequently. To operate this

[7] FERC - Docket No. RM10-23-000; Order No. 1000.

capacity on a seasonal peaking basis, the approximate capacity factors—a measure of their utilization—would average between 11 and 19 percent after 2020. As capacity factors decline and operational functions transition from baseload to cycling, or peaking operations, maintenance and fixed costs to support a plant's operation rise significantly. Based on industry experience, very low capacity factors for traditionally baseloaded plants will significantly increase overall costs due to required upgrades, repairs, staffing needs, and expected increased forced-outage rates. Under these conditions, the eroding plant economics of such generation resources renders their continued operation at risk and subject to potential retirement. In a wholesale electricity market structure, generators may need additional incentives (e.g., capacity payments) to keep low capacity factor fossil generation economic and in service.

4. **Energy and capacity will shift to gas-fired generation, requiring additional infrastructure and pipeline capacity.**
   The implementation of the CPP final rule is expected to accelerate an ongoing shift toward greater use of natural-gas-fired generation. Increased dependence on natural gas use will require pipeline capacity, particularly during the winter season when natural gas use for electric power competes with residential heating. Approximately 60 GW of additional gas-fired capacity is estimated to be in service by 2020, and approximately 80 GW by 2030. The additional capacity plus the higher use of gas-fired generation is expected to increase gas demand in the United States from 39 Bcf/d to 50 Bcf/d—an increase of approximately 30 percent. Local and regional pipeline infrastructure will be needed to relieve pipeline constraints and fuel firming for the electric industry.

Recommendations

1. NERC should continue to update and expand the assessments of the reliability implications of the proposed CPP and provide independent evaluations to stakeholders, states, regulators, and policy makers. NERC should continue to conduct a phased assessment strategy, recognizing that the proposed rule is not yet final and may change. These assessments will continue to provide insight and guidance as the CPP rule is finalized and state, regional, and federal implementation plans begin to materialize.
2. Coordinated regional and multi-regional industry planning and analysis groups should continue to conduct detailed system evaluations to identify areas of reliability concern and work in partnership with states, regions, and policy makers to provide clear guidance of the complex interdependencies resulting from the CPP rule's implementation.
3. Policy makers, states, regions, and regulators (including the EPA) should develop implementation plans that allow for more time to address potential BPS reliability risks and infrastructure deployment requirements during the transition period.
4. The EPA should include a formal reliability assurance mechanism in the final rule that provides the regulatory certainty and explicit recognition of the need to ensure reliability during both the plan development and the implementation period through 2030—and potentially beyond. NERC has outlined a specific series of roles for providing reliability guidance and independent assessments, in the form of a reliability assurance mechanism.
5. State and regional plans should be developed in consultation with reliability authorities—Planning Coordinators and Transmission Planners—to review plans and demonstrate their reliability through established planning analyses and processes.

Chapter 1 – Introduction and Background

The intent of this assessment is to inform regulators, state officials, public utility commissioners, utilities, stakeholders, and other electric organizations of potential resource adequacy concerns and reliability risks of implementing the EPA's CPP rule. This Phase I assessment can help stakeholders (1) make informed decisions about the reliability ramifications of the final rule, and (2) prepare imminent state and regional plans—as well as the requisite infrastructure—necessary to ensure the reliability of the BPS. NERC will continue to provide assessments of the CPP at various stages in the process, including as state and regional plans emerge and are submitted.

This chapter provides a background of NERC's *Initial Reliability Review*, bridging that report with this study and setting the stage for future NERC reliability assessments of the CPP.

Overview of Initial Reliability Review

On June 2, 2014, the EPA issued its proposed *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, referred to as the proposed Clean Power Plan (CPP).[8] The CPP was issued under Section 111 (d) of the Clean Air Act, which introduces CO_2 emission limits for existing electric generation facilities. The proposed CPP aims to cut CO_2 emissions from existing power plants to 30 percent below 2005 levels by 2030. As part of the CPP, initial reductions will be mandated beginning in 2020 and will continue in subsequent years until the full amount of emission reductions are achieved by 2030. 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; (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. Given these criteria, the EPA estimates that 3,104 U.S. fossil-fired electric generating units (EGUs), representing 702,381 MW of existing nameplate capacity, will be subject to the proposed rule's limitations. NERC estimates that this magnitude represents approximately 65 percent of the total existing nameplate capacity in the United States.

According to the proposed plan, this can be achieved by developing state-specific emission rates that limit CO_2 by applying four different building blocks for the Best System of Emission Reduction (BSER). The building blocks provide options to reduce emissions by (1) improving coal unit heat rates, (2) using more natural-gas-fired generating facilities, (3) increasing the penetration of renewable resources, and (4) expanding energy efficiency measures. These building blocks provide some options to attain CPP compliance, but other methods to achieve the specified reductions can be employed. In its *Initial Reliability Review,* NERC conducted a preliminary evaluation of the CPP. This involved, in particular, studying the implications of the building blocks and the overall potential effects of the proposed CPP on BPS reliability. The *Initial Reliability Review* concluded that the implementation of the CPP had the potential to impact the reliability of the BPS.

NERC made the following 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.

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

3. If the environmental goals are to be achieved, policy makers and the EPA should consider BPS reliability concerns around the requisite timing for associated infrastructure deployments.

In addition, NERC made the following recommendations to industry, regulators, and stakeholders:

- The Regional Entities, Independent System Operators and Regional Transmission Organizations (ISO/RTOs), and states should perform further analyses to examine potential resource adequacy concerns.
- 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 that sufficient time is provided for industry to make the necessary changes in order to achieve compliance.
- ISO/RTOs, states, and Regional Entities should prepare for the potential impacts to grid reliability, taking into consideration the time required to plan and build infrastructure.
- 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.
- 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.
- ISO/RTOs, utilities, and Regional Entities (with NERC oversight) should analyze the impacts to ERSs in order to maintain reliability.
- NERC should determine grid-level performance expectations by employing a technology-neutral perspective to ensure ERS targets are met.
- The development of technologies (such as electricity storage) helps support the reliability objectives of the BPS, and these technologies should be expedited to support the additional variability and uncertainty on the BPS.
- ISO/RTOs and system planners and operators should consider the increasing penetration of distributed energy resources (DERs) and potential reliability impacts due to the limited visibility and controllability of these resources.

In its *Initial Reliability Review*, NERC also highlighted its objective of publishing assessments on the CPP as the EPA prepares to issue its final rule, which the EPA has indicated will be released midsummer 2015. Additionally, NERC will perform assessments as state implementation plans and regional implementation plans emerge, as well as once those implementation plans have been finalized. Please see Figure 1 for the scheduled timeline of additional NERC assessments.

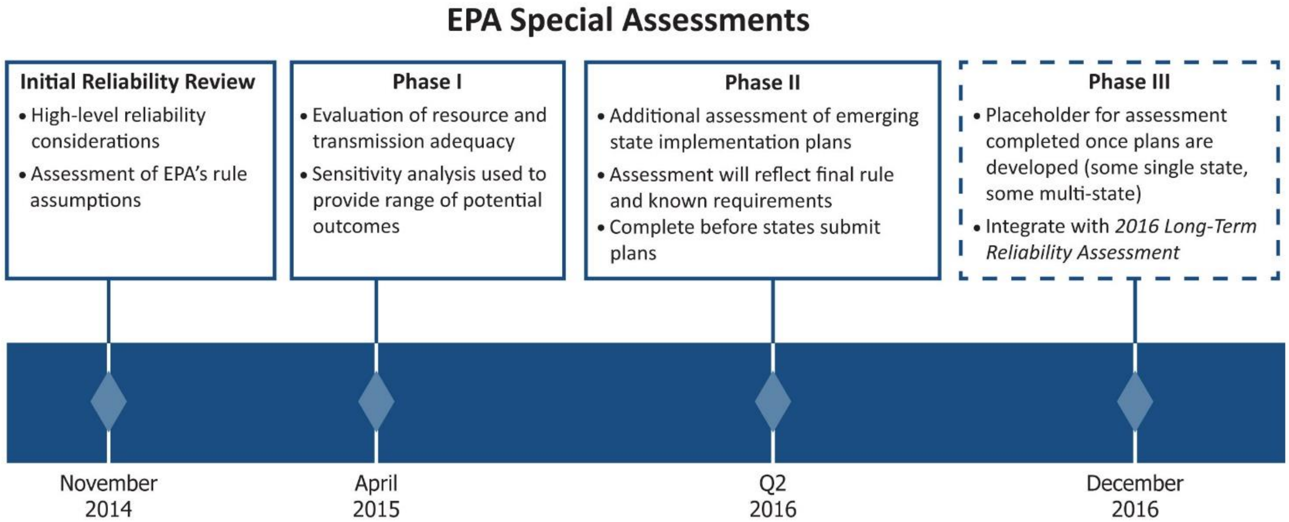


Figure 1: NERC's Multiple-Phase Approach to Reliability Assessment

NERC's Phase I analysis is conducted in three parts:

Part 1: NERC Resource Adequacy Scenarios and Analyses

The CPP offers flexibility to the states on how to most effectively achieve the CO_2 reductions through the use of the four building blocks. As highlighted in NERC's initial assessment, if reductions are not achievable in certain building blocks, offsetting reductions will be needed in the other building blocks. Because the building blocks are interdependent, additional information and assessment is needed to understand what reductions are within the range of moderately to highly likely, what regional options exist for meeting the state-mandated reductions, and what technologies, infrastructure, and resources are needed to achieve compliance.

This assessment is similar to the analysis conducted by the EPA in its *Regulatory Impact Analysis*.[9] NERC established assumptions and parameters based on industry input and publicly available data to gain a better understanding of the range of potential outcomes. NERC used these input assumptions to model results using two different electric generator dispatch models: AURORAxmp and the Integrated Planning Model (IPM).

The key objectives of Part 1 are to:

- Determine how achieving the CO_2 reduction goals as established by the proposed CPP will impact the U.S. generation mix and resource adequacy, based on a set of model input assumptions.
- Conduct sensitivity analysis to examine the range of potential outcomes between state and regional implementations, as well as a range of projections for natural gas prices.
- Compare the AURORAxmp and IPM model outputs.

Approach to Modeling Resource Adequacy

NERC conducted a quantitative assessment that included an analysis of both regional and state implementation, as well as gas price scenarios. NERC staff and industry subject matter experts reviewed the model assumptions and inputs.[10] Table 1 provides an overview of these analyses.

[9] Regulatory Impact Study.
[10] NERC Advisory Group comprised of NERC's Planning Committee members and industry representatives.

Table 1: Summary of Proposed CPP Cases							
Modeling Case		**Reference Case (NO CPP)**	**CPP State Case**	**CPP Region Case**	**Reference Low Gas (No CPP)**	**CPP State Low Gas**
Modeling Case Number		**1**	**2**	**3**	**4**	**5**
Implementation Assumptions	Rate-to-Mass Translation	N/A	Yes	Yes	N/A	Yes
	Gas Price Input	EIA AEO 2014	EIA AEO 2014	EIA AEO 2014	EIA AEO 2014 Low	EIA AEO 2014 Low
	Implementation	N/A	State	Regional	N/A	State

NERC analyzed five scenarios, as outlined below:

1. **Reference Case – No CPP:** Business as usual used as a study benchmark for the EPA's state and regional cases.
2. **CPP State Case – No Interstate Trading:** Rate-to-mass translation proposal for mass-based conversions (using affected unit limitations only) with state implementation.
3. **CPP Region Case – Interstate Trading:** Rate-to-mass translation proposal for mass-based conversions (using affected unit limitations only) with regional implementation.
4. **Reference Low-Gas Case – No CPP and Low-Gas-Price Scenario:** Used as a study benchmark for the EPA's state and regional cases using NERC's low-gas price scenarios.
5. **CPP State Low-Gas Case – No Interstate Trading and Low-Gas-Price Scenario:** Rate-to-mass translation with a state implementation scenario.

Part 2: Transmission Adequacy and Infrastructure Upgrade

In its *Initial Reliability Review*, NERC recommended that the EPA and policy makers ensure the rule provides sufficient time for the industry to address the accelerated change in resource mix. These changes to the system will require transmission additions, enhancements, and operational adjustments to avoid reliability impacts to the BPS. In response to this recommendation, the evaluation of generation and transmission adequacy includes a steady-state (power flow) analysis of the Eastern and Western Interconnections.[11] Generation retirements and projected additions from the Resource Adequacy section of this report are used as inputs for this power system analysis.

The key objectives of Part 2 are to:

- Provide a high-level analysis of transmission reinforcement required to meet the EPA emission reduction proposal.
- Identify major shortfalls of reactive power support on a regional basis.

[11] ERCOT was analyzed separately in their study, as summarized in Part 3.

Approach to Transmission Impacts

NERC analyzed two scenarios based on state and regional implementation of the proposed CPP. In both cases, the analysis centered on a 2020 summer loading condition.

Part 3: Summary of Existing Studies

In its initial reliability assessment, NERC highlighted the need for more industry studies to evaluate reliability. Some ISO/RTOs and utilities have conducted studies that identify reliability challenges associated with the proposed CPP, while other studies indicate less risk. NERC has leveraged key information from these studies to identify cumulative impacts on a region-wide basis. The objectives of this section of the report are to (1) provide a summary of industry studies, highlighting specific areas of concern, and (2) identify parallels between industry studies and NERC's analysis.

Approach to Summarizing Existing Studies

NERC conducted a survey with stakeholders requesting studies of CPP implementation. This section includes a representative number of industry studies and highlights their key issues. It then interconnects them with NERC's overall Phase I assessment.

NERC also analyzed data from stakeholders, who provided additional insight into infrastructure on both transmission and generation, and the necessary lead times to construct, plan, and permit new transmission and new natural gas pipeline infrastructure. These data become important as requisite transmission and natural gas pipeline infrastructure needed to meet the requirements of the CPP within the stipulated time frames is identified.

Resource Adequacy and Transmission Adequacy Study and Scenario Background

In its analysis on both resource and transmission adequacy, NERC retained consultants to employ resource and transmission planning models to study scenarios based on NERC input assumptions. NERC retained BBA Inc. to conduct transmission adequacy modeling and ICF International (ICF) and Energy Ventures Analysis Inc. (EVA) to conduct resource adequacy modeling. Both ICF and EVA were retained so that results and trends could be compared by employing two widely used resource modeling tools in the industry, the IPM and AURORAxmp models.

A graphical representation of the key components of the NERC analysis approach, reliability elements, and relation to NERC's Phase I study is depicted in Figure 2.

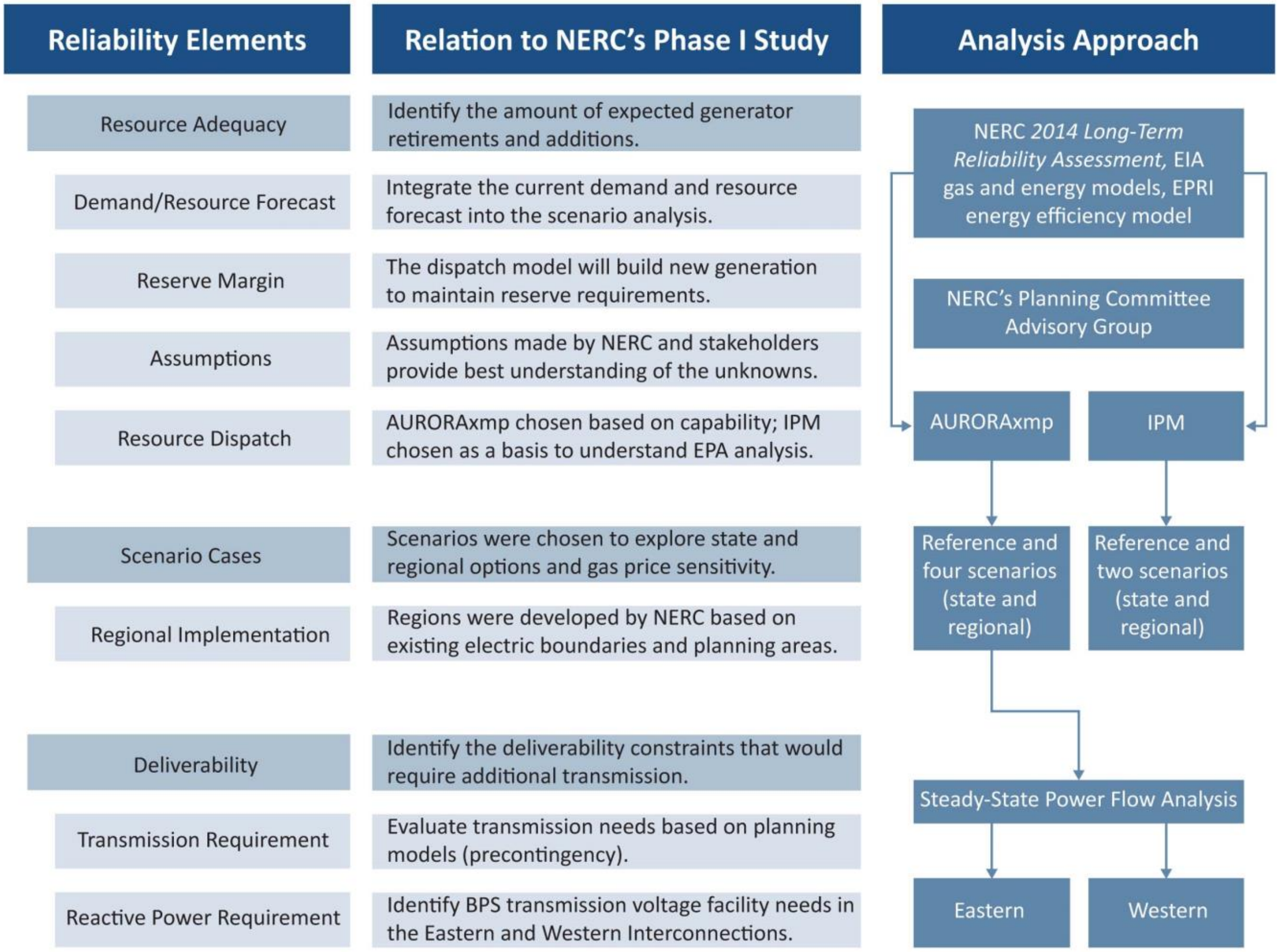


Figure 2: Overview of NERC Analysis Approach for Parts 1 and 2

Chapter 2 – Modeling Assumptions for Resource Adequacy and Power System Analysis

NERC ran a series of resource adequacy models to examine a range of potential outcomes as the electric industry responds to mandates and timeline requirements as stipulated in the proposed CPP. Specifically, the models employed assume that the CO_2 reduction goals as outlined by the CPP will be achieved, providing potential insights to resource adequacy and reliability impacts. The model results illustrate potential scenarios and outcomes at a specific point in time based on input assumptions also applicable to a specific point in time. Therefore, the results are representative of a range of potential outcomes used to assess potential reliability impacts, but are not indicative of what will necessarily happen. Both the AURORAxmp and IPM electric power dispatch models were used in this assessment. All inputs and assumptions were thoroughly reviewed by NERC staff and peer reviewed by industry subject matter experts. An overview of these model inputs for the resource adequacy and power system analysis is presented below.[12]

- **Emission-Reduction Goals**: CO_2 reduction goals achieved, as designated by the proposed CPP.
- **Rate-to-Mass-Based**: NERC utilized the "rate-to-mass translation" proposal as contained in the EPA's November 6, 2014 *Guidelines for Existing Stationary Sources*.[13]
- **Shadow Prices**: Shadow prices for carbon penalties per pound were developed economically so the carbon penalties became high enough to retire or reduce output accordingly, such that the CO_2 reductions would be attained in each state or region.[14]
- **Demand**: Annual electricity hourly demand projections of 1.0 percent growth when averaged over the 25-year period and incorporating energy efficiency growth.[15] This load-growth rate was compared with other load projections, including NERC's 2014LTRA and the EIA's *2014 Annual Energy Outlook* (AEO), and it aligns with these projections.[16]
- **Energy and Capacity**: By fuel technology, as well as prices by NERC Assessment Area.
- **Capacity Additions**: A power plant tracking database was used that consists of a detailed list of planned electric power plants with likelihood of construction. Gas-fired additions based on distance from existing natural gas pipelines; renewable additions are assumed to occur in areas abundant in wind and solar.
- **Capacity Retirements**: Based on cost-optimization analysis.
- **Nuclear Capacity**: All facilities currently under construction will be in service as scheduled; at-risk facilities will remain in service through the time frame of this analysis.
- **Capacity Costs**: New generators will be built and existing generators retired or derated based on economics (i.e., capital costs and operating parameters for existing and new units by fuel type and technology). Both models optimize resources based on the lowest cost to meet electricity demand and maintain reserve margin requirements.
- **Natural Gas Prices**: The EIA's *2014 AEO* Henry Hub natural gas price curves, with an application of prices calibrated on a regional level, using the applicable basis differentials.
- **Transmission Facilities**: Existing substation, transmission, and reactive power facilities taken into account to maximize the use of current facilities.

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[12] Detailed data input assumptions and model results for both the AURORAxmp and IPM models are published with this report and available at: http://www.nerc.com/Pages/default.aspx.

[13] Additional Information Regarding The Translation Of Emission Rate Based CO_2 Goals To Mass Based Equivalents.

[14] A shadow price is the estimated price of a good or service for which no market price exists.

[15] Electric Power Research Institute's U.S. Energy Efficiency Potential Through 2035 Report.

[16] NERC's 2014 LTRA and EIA's 2014 Annual Energy Outlook (AEO).

- **Renewable Energy**: Publicly available data from EIA and NREL, as well as other data from trade group databases, was used as model inputs for existing and projected renewable energy. For projected renewable resources with a 1–5-year in-service time frame, the assumptions were as follows: nearly 100 percent completion of projects under construction, 50–75 percent of capacity under advanced development (varies by projected online date and technology), and 5–30 percent of capacity under early development. For long-term renewable capacity additions, the following factors were also taken into consideration: (1) state renewable resource quality and potential, (2) state renewable portfolio standards, (3) historical/forecast future renewable generation growth trends, and (4) data from the DOE's *2014 Annual Energy Outlook*.

The following assumptions were used for the scenario cases:

Mass- vs. Rate-Based Limitation Approach

The proposed EPA CPP allows the states to select between CO_2 rate-based limitations (lbs CO_2/MWh) or a mass-based limitation (tons/year) in their state implementation plans. To be approved, the state plan must demonstrate that it is enforceable and compliant with the proposed EPA state CO_2 emission rate limitation. Subsequent to its proposal, the EPA issued guidance to states that outlined state mass-based cap limits for the affected sources within each state, which the EPA would automatically approve.

Based on discussions with states and utilities, there is an overwhelming consensus that a majority of states may adopt a mass-based cap that would be much simpler to implement and enforce through an administered cap-and-trade program, such as the one used by the nine states within the RGGI or California. The other 39 contiguous states would need to develop similar legislation and regulations to allocate or auction a set number of allowances each year. The affected sources must hold and retire a sufficient number of allowances to cover their annual emissions each year beginning in 2020. This study incorporates these preapproved state-by-state mass limitations. It would be far more complex for states to pursue the alternative state CO_2 rate-based limitation as states would be required to develop individual unit CO_2 rate limitations and net output power restrictions for each affected source that can be enforceable by integrating these conditions into their operating air permit. The expertise to develop such CO_2 rate limitations to adjust for the normal changes in heat-rate efficiency through the operating cycle would require detailed unit-specific engineering design and historical operating data. Such data takes time and resources to collect and evaluate.

- **Low-Gas-Price Scenario**: EIA's Low-Gas-Price Case was used with an application of prices calibrated on a regional level, using the basis differentials.
- **Regional Implementation Scenario**: For multi-state implementation, NERC developed emission-trading regions, leveraging existing market areas, FRCC and SERC, and the existing RGGI states.

Chapter 3 – Resource Adequacy Assessment

The CPP offers flexibility to the states on how to most effectively achieve the CO_2 reductions through the use of the four building blocks or other means. NERC used two models to assess the sensitivity impact of varying factors. The objectives of the resource adequacy study are listed below.

Objectives

- Assess how the heat-rate assumptions, gas use, renewable energy, and energy efficiency assumptions impact generation retirements and renewable- and gas-generation needs.
- Conduct sensitivity analysis to understand the range of potential outcomes between state and regional options.
- Compare the results to the IPM model output.
- Identify resource adequacy trends and results using NERC's *2014 LTRA* as a starting point.

Background

NERC used the commercially available AURORAxmp electric power market forecasting tool. AURORAxmp is a fundamentals-based power market model that economically dispatches generation capacity to simulate the operations of each power market in the continental United States. The model optimizes generator dispatch by using the lowest-cost resources to meet electricity demand in a given region at the hourly level and builds the most economic new resources to meet reserve margin targets and future load growth. This model examined the following cases: (1) Reference Case (no CPP), (2) CPP state implementation, (3) CPP regional implementation, (4) Low Gas (no CPP), and (5) Low Gas with CPP state implementation.

These multiple scenarios were selected to assess the sensitivity impacts of varying factors. Specifically, the EPA provides potential implementation options using either state or multi-state compliance approaches. Assessing each approach provides a range of resource adequacy implications to inform stakeholders and policy makers. Similarly, a lower natural gas price scenario was modeled to isolate and examine the effects of this component on both energy and capacity.

Additionally, NERC performed modeling with the IPM model (the EPA's analysis also used the IPM model) by applying the input assumptions described in Chapter 2. IPM was chosen as a modeling platform to complement the results of the AURORAxmp modeling effort, and also as a comparison to the EPA's analysis.

The model assumes that the market will reduce emissions to a level that exactly meets CPP compliance. In practice, resource planners target a rate of emissions that is well within the necessary compliance requirements to avoid any risk of noncompliance—a condition referred to as "over-compliance." Accordingly, plans will likely be developed to accommodate a specific compliance strategy.

Scenario Modeling Cases

NERC conducted a resource adequacy analysis by running two different models—AURORAxmp and IPM—with the application of the input assumptions described in Chapter 2. These models examined the following cases: (1) Reference Case (no CPP), (2) CPP state implementation, (3) CPP regional implementation, (4) Low Gas (no CPP), and (5) Low Gas with CPP state implementation.

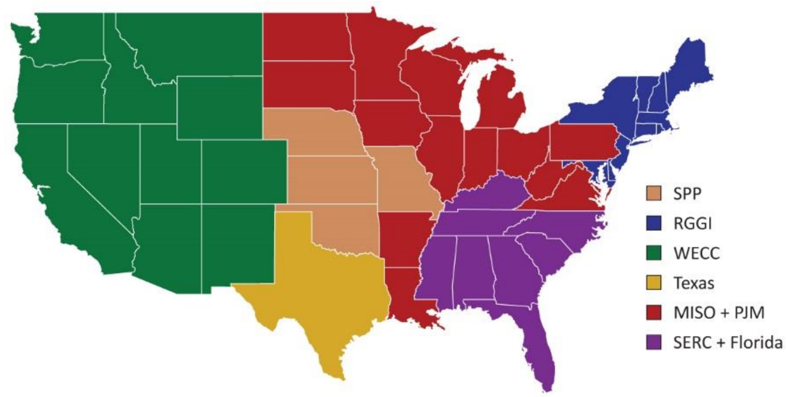

Figure 3: NERC Regional Trading Map Assumptions

NERC-assumed compliance regions are shown in Figure 3. NERC scenarios that reflect possible outcomes of the CPP are specified in Figure 4. CPP State, Regional, and Low-Gas scenarios assume that states implement the CPP standards as mass-based (or tonnage-based) caps on CO_2 emissions rather than as emission-rate standards, as the EPA modeled the program in its *Regulatory Impact Analysis*. NERC's assumed mass caps were based on the EPA's calculated caps, as presented in the EPA's November 2014 *Rate-to-Mass Technical Support Document*. In all CPP scenarios, the mass caps were imposed on existing emitting sources only. Capacity coming online after 2014 was not assumed to be subject to the caps as it falls under the requirements of the EPA's New Source Performance Standards (NSPSs). The CPP state scenarios assume that states achieve the standards individually, without any mechanism for contributing to each other's compliance needs other than through existing transmission resources. Within each state, affected sources meet the state mass limit through CO_2 allowance trading, resulting in an allowance price in dollars per ton emitted for each state. The CPP regional scenario assumes that states meet the standards as part of regional (multi-state) groups, assuming trading of allowances across state borders and regional CO_2 allowance prices. Lower natural gas price scenarios were modeled to isolate and examine the effects of this component on both energy and capacity.

NERC's *Initial Reliability Review* focused significantly on the EPA building block assumptions and the achievability of those building blocks, as well as the potential implications to BPS reliability. Phase I assumes that the building blocks, as well as any other attainable methods, will be used by industry to develop a BSER and, as a result, that CO_2 emission reductions are met as stipulated in the proposed CPP.

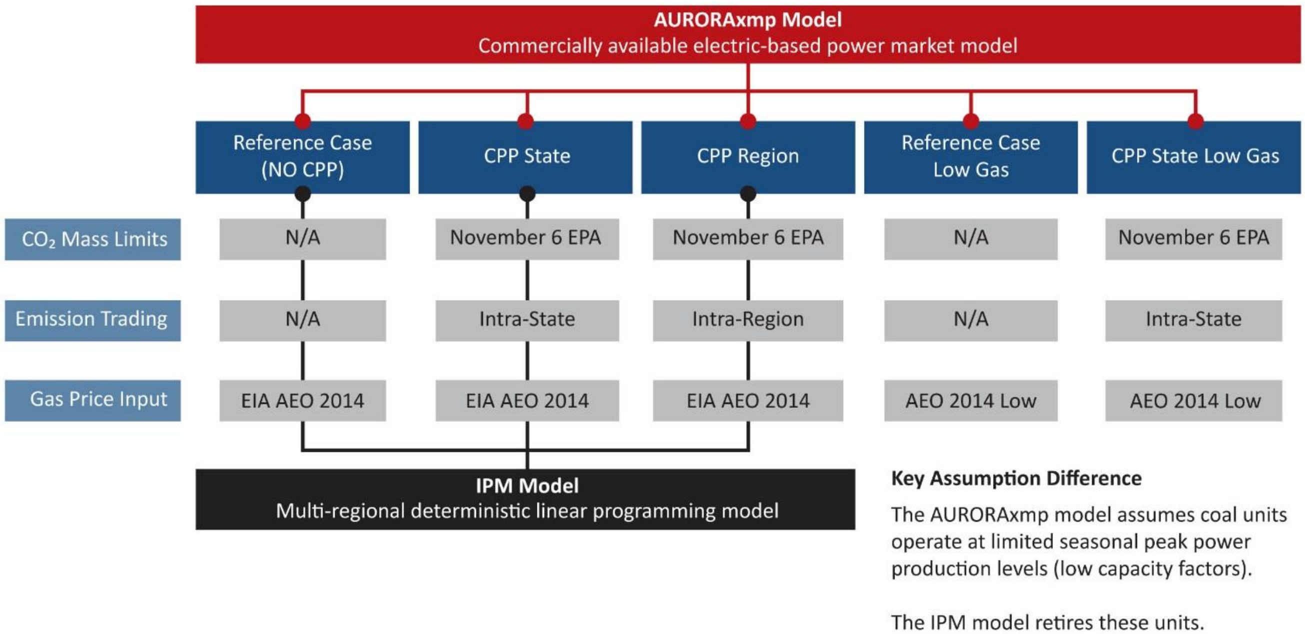

Figure 4: Summary of NERC Clean Power Plan Scenario Cases

The EPA CPP proposes state-specific limitations based on the application of four building blocks (process efficiency improvements, gas redispatching, clean energy, and energy efficiency) and assumed performance for each element. This approach results in a wide range of state requirements and compliance costs. The gas redispatching building block contributes most directly to state rate differences. States with large amounts of underutilized gas combined-cycle capacity in 2012 were given strict limitations, assuming that all of this capacity could displace coal unit generation. As a result, the limits assume existing coal generation would be completely displaced in 11 states (AK, AZ, CA, CT, MA, MS, NV, NH, NJ, OR, and WA) and by more than 90 percent in two other states (FL and NY). In these cases, the state CO_2 rates are very close to the natural gas combined-cycle (NGCC) CO_2 emission rates. On the other hand, 12 states (HI, IN, KS, KY, MD, MT, NE, ND, OH, TN, WV, and WY) had little to no underused natural gas combined-cycle capacity, so the final state rate limitation was set to be closer to the average coal limitation.

The differences in state limitations directly contribute to significant differences in the CO_2 penalties between states and can change power flows between states. Under the CPP, the costs include CO_2 allowances (i.e., shadow prices) as shown in Figures 5 and 6. The models assumed trading of carbon emissions would occur in regional groupings across typical RTO/ISOs and contiguous regions. Whereas carbon shadow prices among states indicate differing economic values, NERC's model assumes trading would occur using physical power flows, which may not capture the same level of value that other potential trading mechanisms might provide as a result of a CPP final rule.

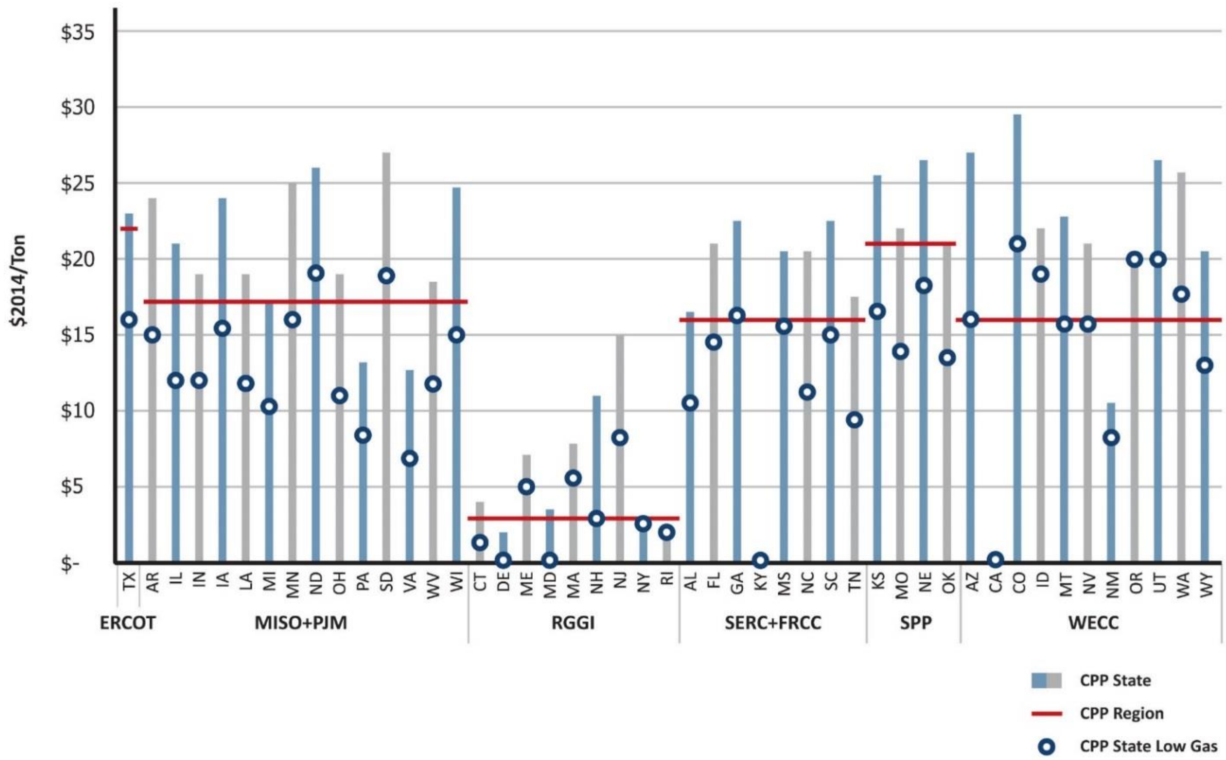

Figure 5: AURORAxmp Model CPP State, Region, and CPP State Low-Gas Case Shadow Prices in 2020

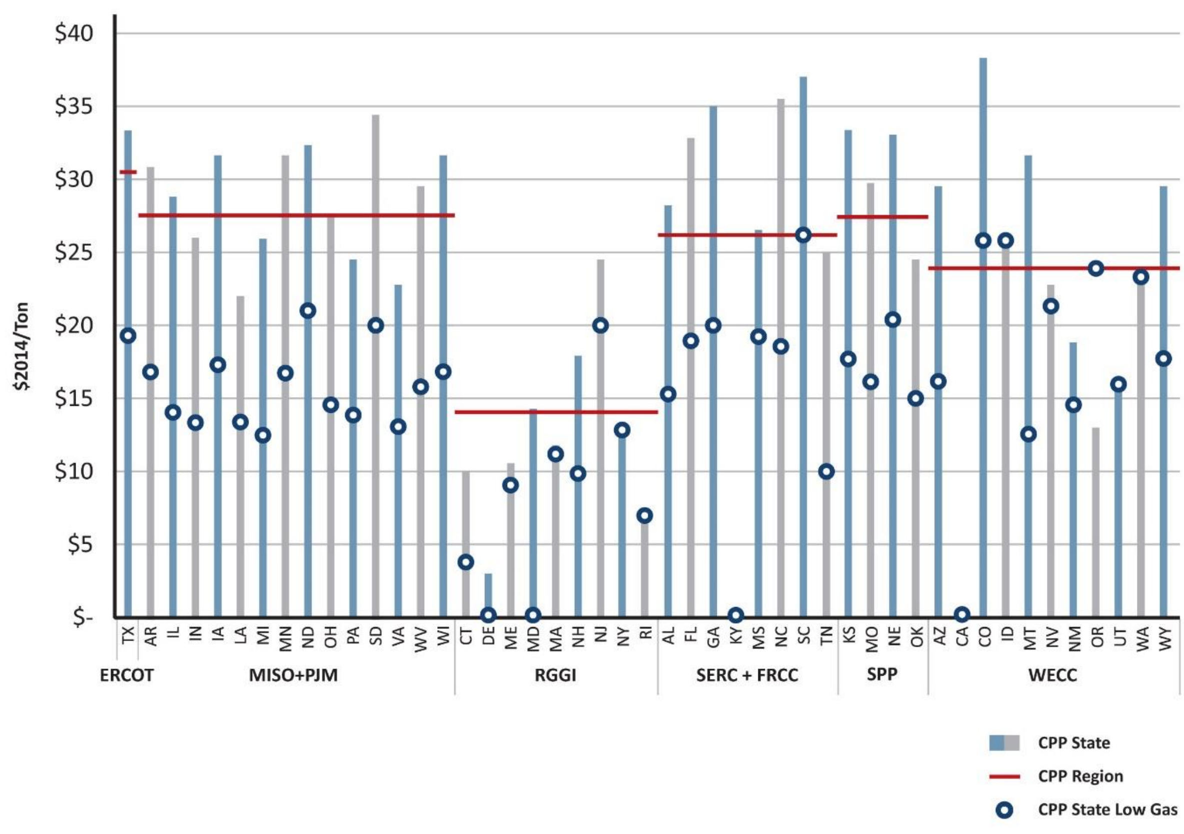

Figure 6: AURORAxmp Model CPP State, Region, and CPP State Low-Gas Case Shadow Prices in 2030

If a unit retires, it reduces emissions under the cap for a state or region, thereby freeing up space for other units, such as lower-emitting gas units, to operate. Both IPM and AURORAxmp can add new generation capacity to replace generation and capacity lost by retirements and meet growing demand where necessary. New capacity is not covered by the CPP emission caps; models can add capacity with any level of emissions, as long as the unit emits at a rate that complies with the assumed NSPS requirements. The models must balance retirements with new capacity and capacity transfers via transmission resources to meet specified NERC reserve margin requirements in every year.

Key Results from the Resource Adequacy Assessments

The following section provides a summary of key results of the NERC Reference Case, CPP State Case, and CPP Regional Case. For the purposes of this summary, the discussion focuses on national-level results, along with select results for multi-state regions, where appropriate.

CPP Impact on Capacity

All scenarios indicate modest acceleration of retirements but project a large shift in use and operational behavior of coal-fired generation:

- Approximately 18 GW of coal-fired generation retires between 2016 and 2020, and an additional 18 GW retire between 2020 and 2030 under the CPP State Case. Nearly 40 GW of coal-fired generation retires in the CPP Low-Gas State Case—20 GW between 2016 and 2020, and 20 GW between 2020 and 2030. In addition to retirement of coal-fired plants, remaining coal runs at significantly lower capacity factors (which is further detailed in the CPP Impact on Coal Generation (Energy) section).

Non-Hydro Renewable Capacity

Non-hydro renewable generation resources increase—but only moderately—due to the expiration of Production Tax Credits (PTCs), the reduced Investment Tax Credits (ITCs), and the lower cost of natural gas generation.

- Approximately 8 GW of wind and 5 GW of solar are built between 2016 and 2020, and 15 GW of wind and 7 GW of solar between 2020 and 2030.
- Based on NERC's modeling assumptions, State and Regional Cases were not significantly different from a generation capacity perspective. This similarity is a result of non-hydro renewable resources primarily being built to accommodate renewable portfolio standards (RPSs), which are equivalent in both state and regional scenarios.
- While generation use and ability to trade varied, the economic benefits in the regional scenario did not significantly affect retirement decisions.

Table 2 shows capacity changes among generation types.

Table 2: NERC-AURORAxmp CPP State and Regional Cases (GW) Capacity Change[17]				
	CPP State		CPP Regional	
	2016-2020	2020-2030	2016-2020	2020-2030
Coal Retirements	18	18	17	20
Net Oil and Gas Retirements	25	24	24	24
Natural Gas Additions	61	73	63	79
Wind Capacity Additions	8	15	8	15
Solar Additions	5	7	5	7
Total Additions	74	95	76	101
Total Retirements	43	42	41	44

[17] Cumulative Oil and Gas retirements include peaking units, steam gas units, and steam oil units. Cumulative Natural Gas (NG) additions include Gas Turbine (GT) and Combined-Cycle Gas Turbine (CCGT) units.

Figure 7 shows the capacity mix of the Reference (no CPP), CPP State, CPP Regional, and CPP State Low-Gas Cases modeled using AURORAxmp. Coal capacity as a percentage of total market share drops by 5.1 percent in the CPP State Case in 2030 from its reference 2016 level and by 5.5 percent in the CPP State Low-Gas Case in 2030 compared to its reference 2016 level. Natural gas makes up for most of the coal decline, increasing its total capacity share by nearly 5 percent in the CPP State Case in 2030 compared to the Reference Case in 2016, and by 5.5 percent in the CPP State Low-Gas scenario in 2030. State and Regional Cases yield similar results for coal retirements as well as natural gas and non-hydro renewable additions. However, a final CPP rule could incorporate different emissions trading scenarios outside of the regional scenarios modeled by NERC, which modeled trading around typical ISO/RTO regions.

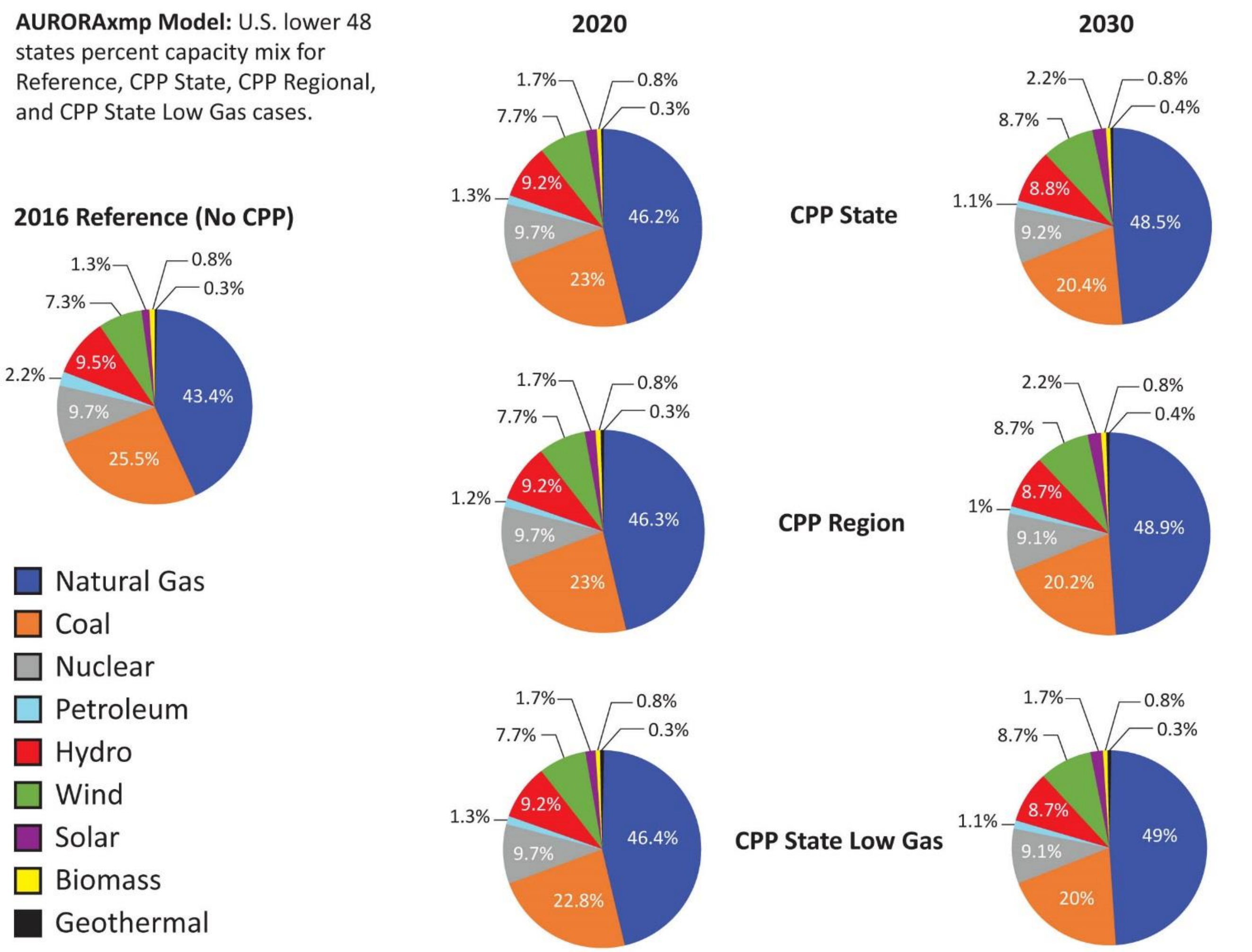

Figure 7: Percent Capacity Mix for NERC Scenario Cases

The changes in capacity (GW) for all fuel types from 2016 to 2020 and from 2016 to 2030 are shown in Figure 8. The total change of natural gas capacity is nearly doubled after the year 2020 when the CPP starts to take effect, and decreases in coal capacity double.

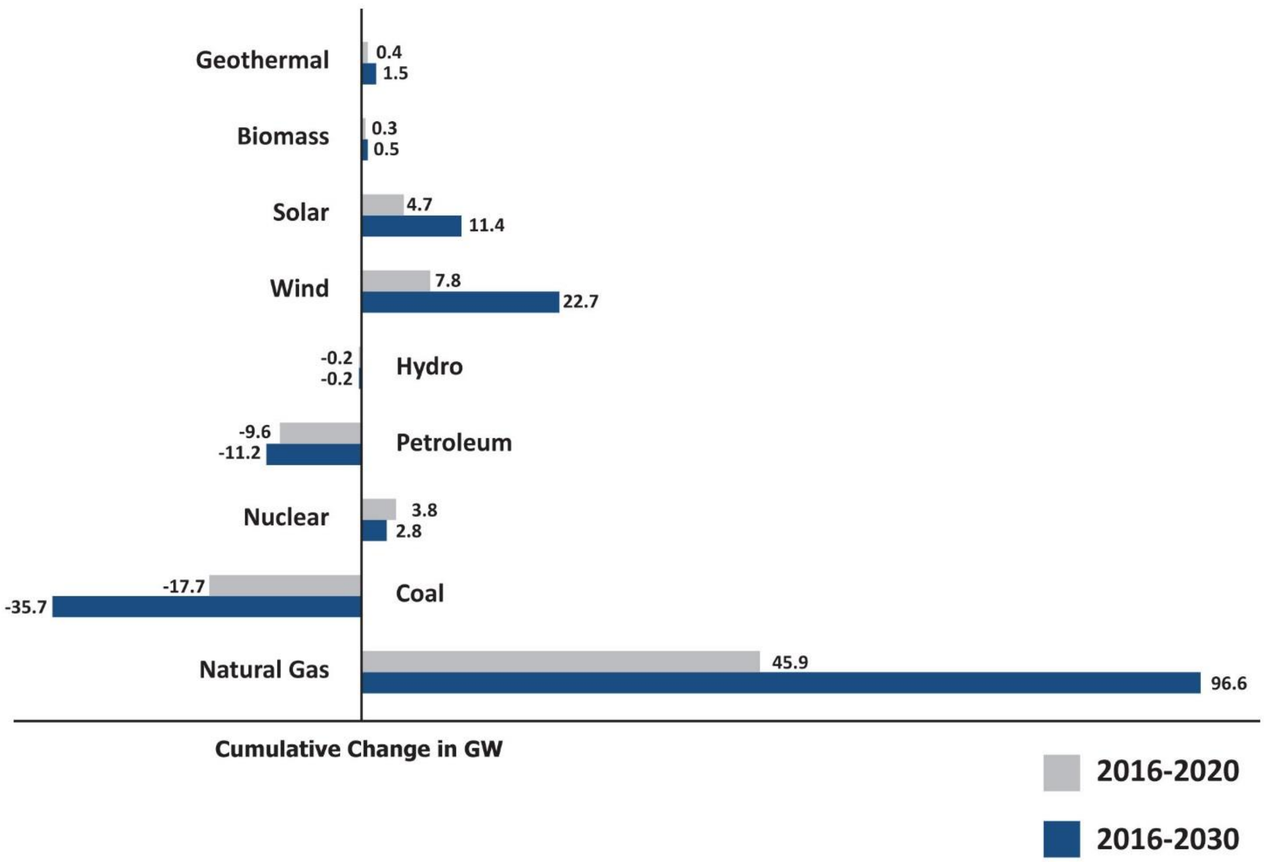

Figure 8: AURORAxmp Change (GW) in Capacity Mix for CPP State Case from 2016 to 2030

Changes in coal generation in terawatt hours are shown in Figure 9, comparing the Reference Case to the CPP State Case, CPP Regional Case, and CPP State Low Gas Case. The figure shows the decline in coal generation in terawatt hours as a result of the CPP.

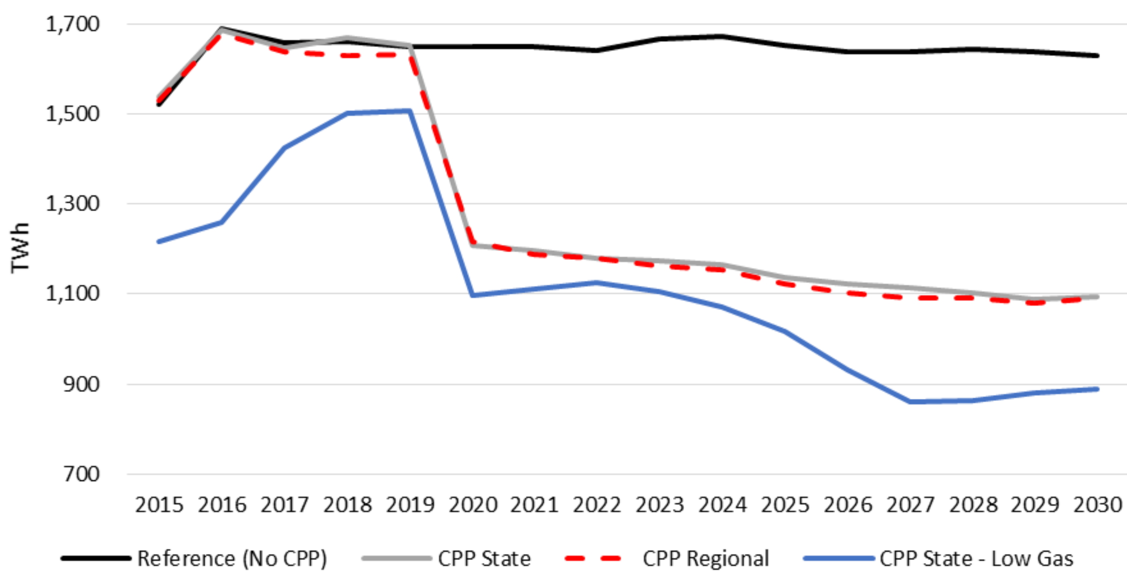

Figure 9: AURORAxmp Projected Coal Generation (TWh) – NERC Reference and Scenario Cases

Conceptual Example Demonstrating "At Risk" Coal Generation due to Low Capacity Factors

NERC assumes that a carbon trading market will emerge; however, coal capacity retirements could increase by an additional 14 to 22 GW if additional incentives (e.g., capacity payments) do not develop in certain markets. As part of a lowest-cost generation mix, some coal generation would be operated on a seasonal basis. Should the capacity market not develop to cover the fixed costs for these coal assets, they could retire and be replaced by higher-cost, new-peaking, gas-fired capacity.

Baseload power plants (specifically coal plants for this illustration) are designed to run at high capacity factors and at high output levels. A plant running at 100 percent capacity factor would operate 8,760 hours per year—operating at 200–500 hours per year, the capacity factor would be under 6 percent. This lower capacity factor would cause the plants to operate on a much higher $/MWh output cost.

Fixed Costs: The fixed costs for a power plant are significant. Since these costs will not change whether the unit is operated at 100 percent or 6 percent, that will impact the $/MWh calculation dramatically.

- Fixed costs include certain operations and maintenance expenses, administrative expenses, property taxes, carrying charges, and corporate overheads. For a 600 MW unit, these might be approximately $25M annually (this is an estimate for illustrative purposes).
- $25M/600 MW/8760 hours of run time would equate to a fixed cost of $4.75/MWh.
- $25M/600/500 hours of run time would equate to a fixed cost of $83/MWh.
- In addition, the unit incurs auxiliary power expenses for minimum heating, lighting, and other minimal running expenses.

Start-up Costs: If a unit is operated at only 500 hours per year, the unit is likely either (1) only needed during peak load days or (2) used as a cycling unit to meet daily short-term load needs.

- Depending on the size of the unit, it can cost over $100,000 each time a unit is started from a cold start position. Even if the 600 MW unit used in the example were run for 24 hours after starting up, it would cost an additional $6.90/MWh ($100,000/600/24). This makes it uneconomical in most cases to utilize a baseload coal unit as a cycling unit.
- This $/MWh example ignores the additional structural damage done to a unit each time it is started. This increases the need for more frequent maintenance outages.
- Just being idle also increases the potential for forced outages. This was the main reason PJM re-implemented a winter testing procedure for units that had not operated for several weeks before the winter period.

Heat Rate: Another reason a unit might operate at a low capacity factor is when it is needed in reserve for voltage support, black start, or transmission congestion. In these situations, when a unit is not needed at full load, it will operate at a suboptimal heat rate factor. This causes inefficiencies in the plant's operation and higher $/MWH costs.

- The heat rate for units operating at minimum load is approximately 20 percent higher (i.e., less efficient) than a unit's heat rate operating at maximum output.
- Coal pile inventories sitting unused tend to collect moisture, causing further inefficiencies and higher heat rates.

Additionally, retirement decisions, to some extent, are also driven by whether the plant is in the market or in a vertically integrated regulatory structure. Units with low capacity factors in a market may succumb to the cost structure challenges highlighted above. However, in a vertically integrated environment, the plant is already in the rate base and may be kept in service for various reasons, including local politics or the impact on the local economy. Vertically integrated utilities may have to prove to the state utility commission that there are soft benefits to keeping the asset in the rate base.

Table 3 shows the IPM capacity changes in GW between 2016 and 2020 and between 2020 and 2030 for the CPP State and Regional Cases. The model shows that most of the coal retirements, approximately 31 GW in both the State and Regional Cases, happen between 2016 and 2020 and about 2 to 3.5 GW retires between 2020 and 2030. Similarly, non-hydro renewable capacity increased between 2016 and 2020; nearly 24 GW for wind and about 7 GW for solar capacity.

Table 3: NERC-IPM Model GW Capacity Change[18]

	CPP State		CPP Regional	
	2016-2020	**2020-2030**	**2016-2020**	**2020-2030**
Coal Retirements	31	2	31	3
Net Oil and Gas Retirements	16	8	14	10
NG Additions	83	52	82	51
Wind Capacity Additions	24	2	22	2
Solar Additions	7	13	7	13
Total Additions	**114**	**67**	**111**	**66**
Total Retirements	**47**	**10**	**45**	**13**

[18] Cumulative Oil and Gas retirements include peaking units, steam gas units, steam oil units, and Combined Cycle Gas Turbine (CCGT) units. Cumulative Natural Gas (NG) additions include Gas Turbine (GT) and Combined Cycle Gas Turbine (CCGT) units.

CPP Impact on Coal and Gas Generation (Energy)

One of the underlying causes for the decline in coal capacity and generation is the carbon penalty component of the new dispatch. To reduce carbon emissions to meet the proposed EPA program state mass limitations, the generation dispatch shifts away from coal toward a greater mix of lower-emitting resources. Overall, the AURORAxmp model shows that the CPP would cause a 27 percent drop in coal generation in 2020 from the Reference (no CPP) Case and a 33 percent drop by 2030. This decline in coal generation as a result of the CPP implementation will largely be replaced by NGCC generation.

Figure 10 shows coal consumption declining by 41 TWh between 2016 and 2020 and by an additional 20 TWh between 2020 and 2030 in the Reference (no CPP) Case. However, in the CPP State Case, there is a 479 TWh decline in coal consumption from 2016 to 2020 and an additional 113 TWh decline from 2020 to 2030.

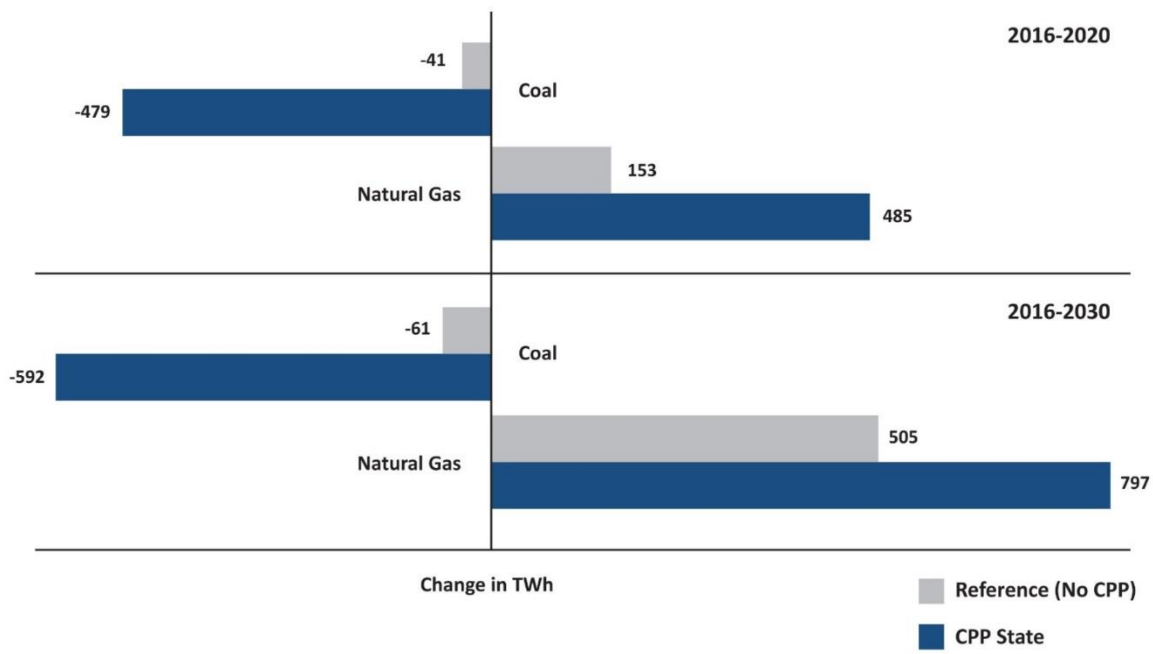

Figure 10: AURORAxmp Energy (TWh) Coal and Natural Gas Generation Change from 2016 to 2020 and from 2016 to 2030

The continuing shift to natural gas will require additional pipeline capacity to support fuel needs.

- In the CPP State Case, natural gas generation increased from approximately 970 TWh in 2016 to 1,770 TWh in 2030. When employing the CPP State Low-Gas scenario, natural gas generation increased from approximately 1,390 TWh in 2016 to 1,970 TWh in 2030.
- Approximately 11 Bcf/d of additional natural gas supply is needed to support the new gas-fired generation by 2030.

The IPM model confirms this same trend for the period between 2020 and 2030. The CPP requirements force a change in the generation mix, as the system must increase the dispatch of new resources and lower-emitting existing resources to displace higher-emitting resources under the emission cap limits.

Figure 11 shows the IPM share of generation mix by type for 2020 and 2030 by case. The impacts of the CPP are very similar in both the CPP State and CPP Regional Cases. In both cases, gas increases its share to over 35 percent at the expense of coal, as compared to 28 percent in the Reference Case. Coal generation declines to approximately 28 percent, as compared to over 36 percent in the Reference Case. Generation shares of other technologies remain equivalent across the Reference and CPP Cases.

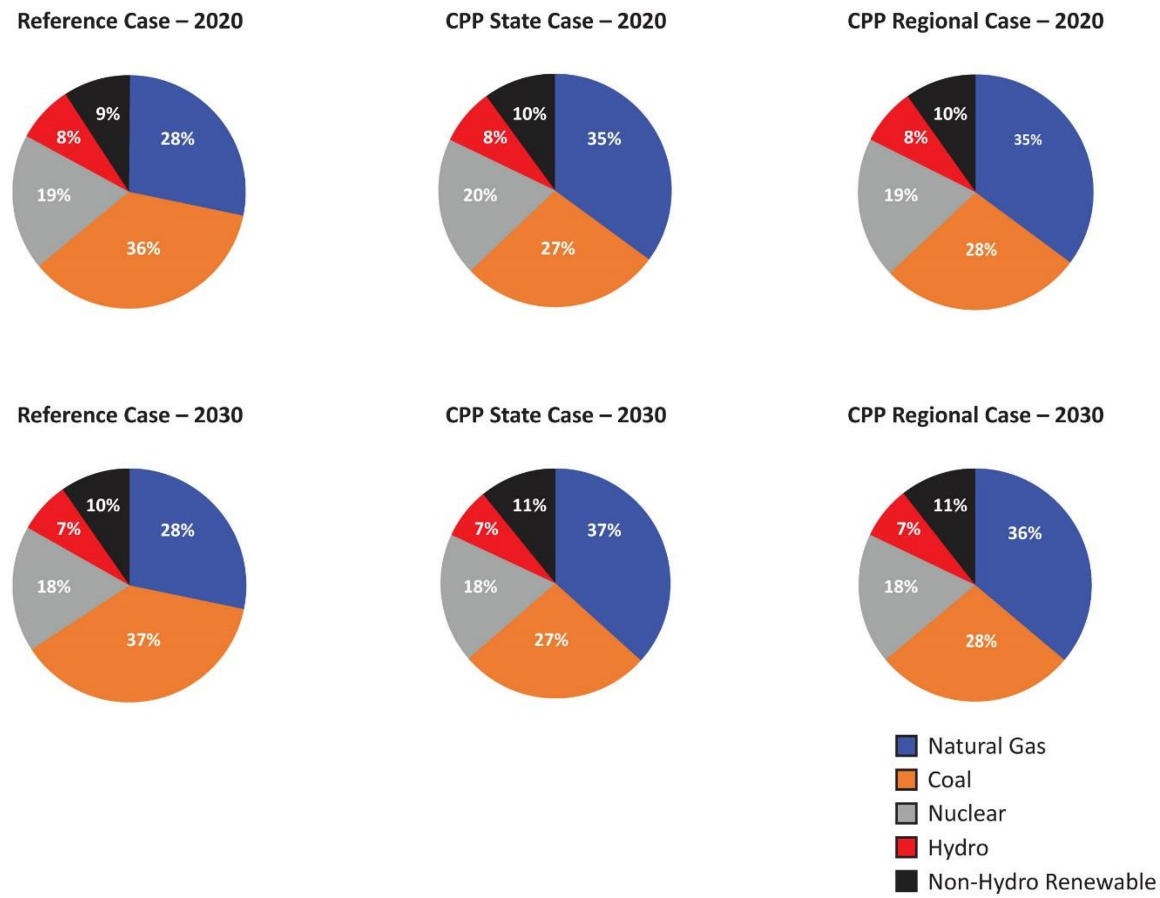

Figure 11: IPM Generation (Percentage of Total GWh) Mix by Type, 2020 and 2030[19]

Impact of Increased Use of Natural-Gas-Fired Generation on Infrastructure

The implementation of the proposed CPP will cause a shift in the resource mix due to the retirement of higher-emitting CO_2 units being displaced by lower-emitting CO_2 units. The higher-emitting units are predominantly coal-fired generation being replaced by natural gas and renewable generation. The AURORAxmp model demonstrates a 13 percent decline in coal generation capacity and a 36 percent increase in natural-gas-fired generation capacity by 2030 from the reference 2016 levels, including gas turbine and steam turbine units. In addition, about 22 GW of at-risk coal generation could potentially retire. The AURORAxmp model shows a significant shift in the use of natural gas generation to make up for the decrease in coal-fired generation. Natural gas electricity generation increased by approximately 300 TWh in 2020 and 2030 when comparing the Reference Case to the CPP State Case. This results in an approximate 7 Bcf/d increase in natural gas use.

[19] Non-hydro renewable GW capacity includes existing and planned biomass and landfill resources and existing and planned wind and solar capacity resources.

In the CPP State Low-Gas scenario, the results demonstrate additional natural gas usage compared to the CPP State and Regional Cases. In 2020 and 2030, there are increases of 459 TWh and 495 TWh, respectively, in natural gas from the Reference (no CPP) Case, as shown in Figure 12.

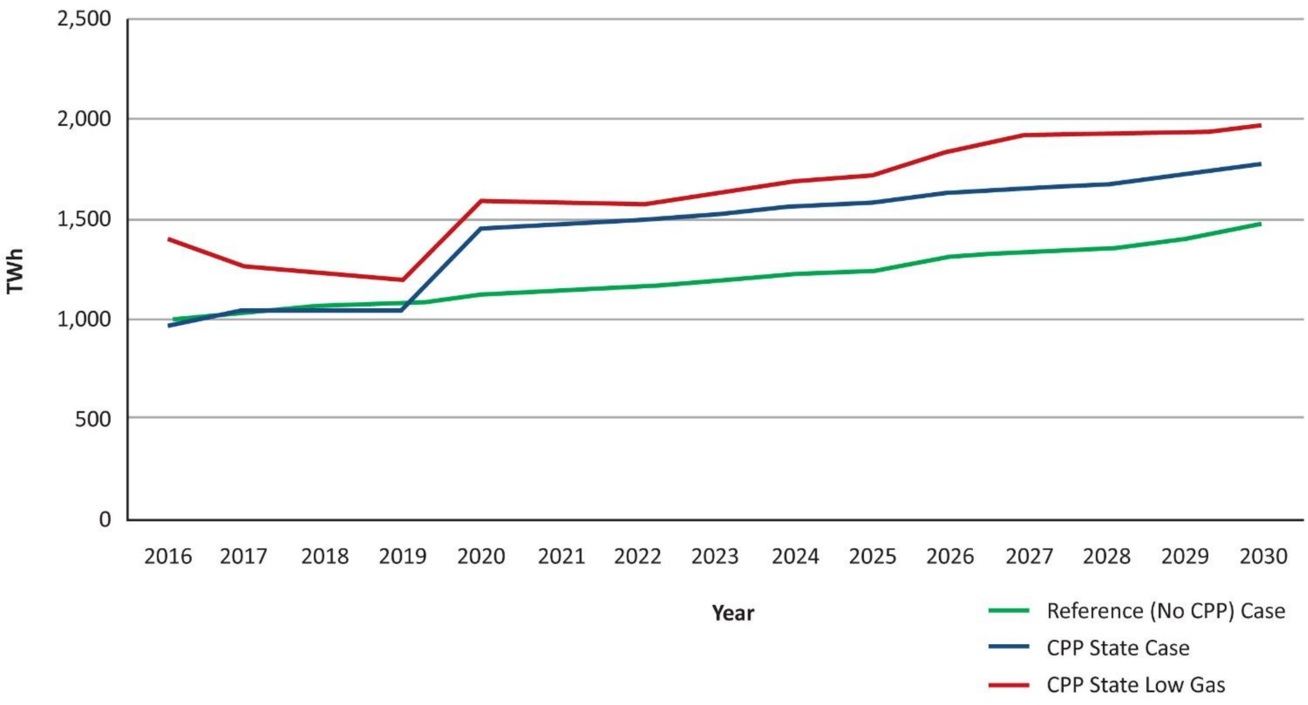

Figure 12: AURORAxmp Projected Natural Gas Generation (TWh) – NERC Reference and Scenario Cases

As a result of the CPP, there is an increased use of natural gas resources. Figures 13 and 14 demonstrate the increased reliance on natural-gas-fired generation.

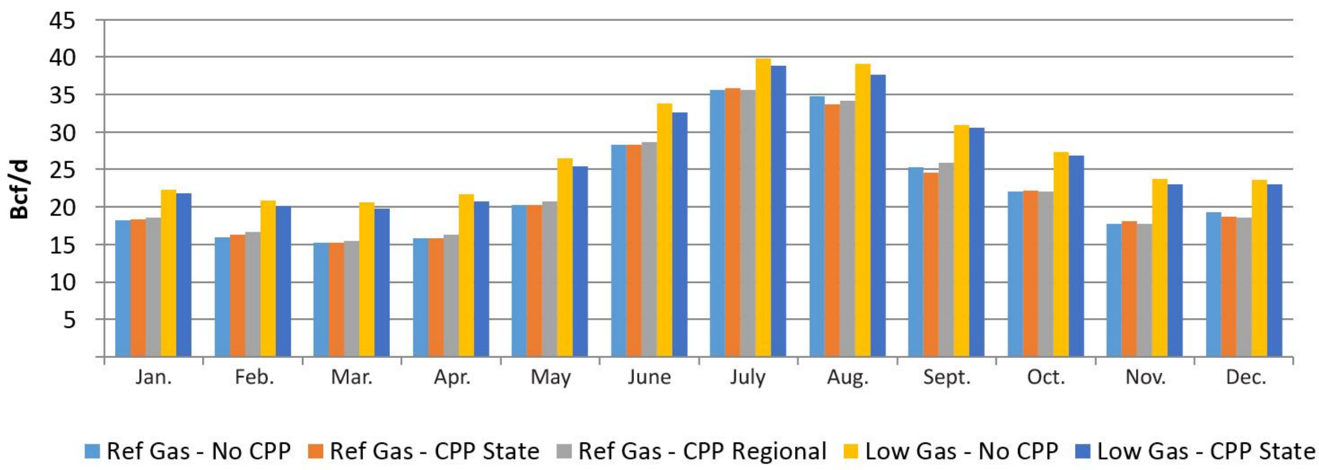

Figure 13: AURORAxmp Average Gas Demand (Bcf/d) Between 2016 and 2020

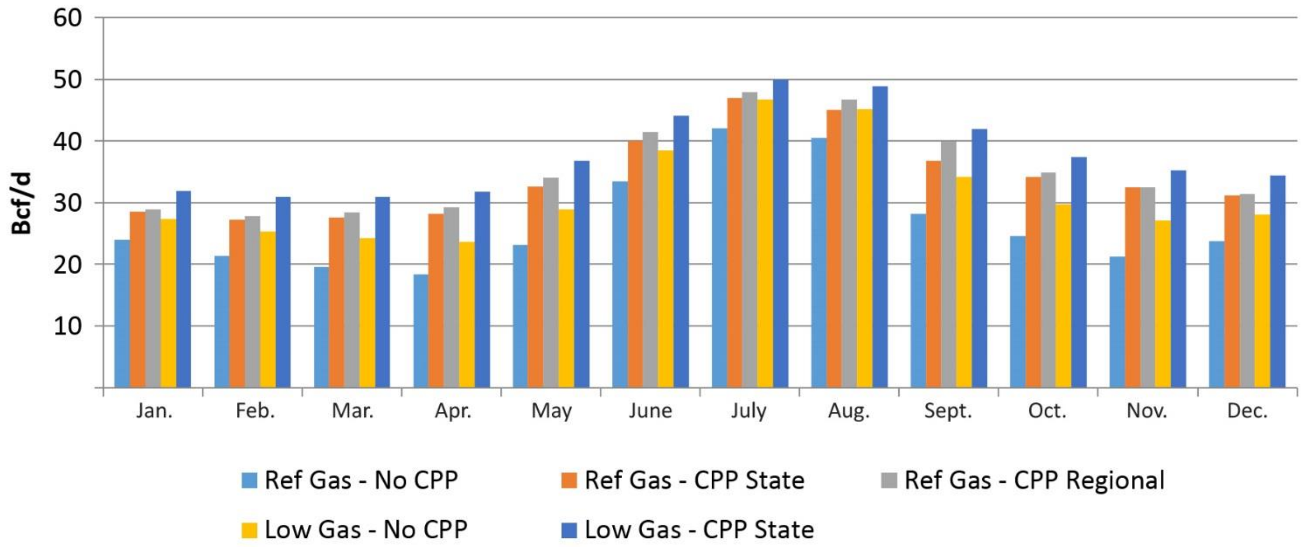

Figure 14: AURORAxmp Average Gas Demand (Bcf/d) Between 2020 and 2030

As shown, the natural gas use increases from 39 Bcf/d in the Low-Gas CPP State between 2016 and 2020 (Figure 13) to 50 Bcf/d in the Low-Gas CPP State for 2020–2030 (Figure 14) for the month of July. This represents an approximate 30 percent increase in gas use of existing and planned natural-gas-fired generation to support the proposed CPP target. This 30 percent of extra capacity needed to support CPP would have to compete with existing firm gas capacity procured for residential heating and industrial needs. In addition to electric infrastructure, gas infrastructure would also need to be enhanced to accommodate the increased consumption of gas. As delineated in Chapter 5, natural gas pipeline projects require approximately three years from conception to inception. Additional time will be required if the project is larger and complications arise during construction.

Non-Hydro Renewable Generation and Capacity Reliability

The North American BPS is currently undergoing a significant change in the mix of generation resources. Driven by a combination of factors, the rate of change in certain areas is having a tremendous impact on the planning and operation of the BPS. For example, current environmental regulations are contributing to substantial retirement of conventional coal-fired generation, while RPSs and other factors are driving the development of VERs. The CPP rule, as proposed, will further challenge BPS reliability as a result of increased coal retirements, the increased utilization of natural gas generation, and non-hydro renewable energy sources such as wind and solar energy. This resource shift has impacted and will continue to impact BPS operational characteristics and long-term resource planning. The additional renewable power will not only increase the need for ancillary services (e.g., frequency response and reserves) but also create additional planning and operational needs as its market share continues to grow. The model showed that given the projected increases in wholesale power costs, higher retail prices will spur some incremental renewable power from distributed generation resources not under grid operator control—especially in areas with good solar and wind resources and state incentives. To accommodate the higher penetration of VERs, operators need to adjust their practices and rely on more flexible resources to ensure voltage and frequency support are maintained within acceptable margins while maintaining frequency.

Non-Hydro Cases Model Results: NERC evaluated the reliability impacts of the increased renewable generation resulting from the implementation of the proposed CPP carbon emission reduction goals as follows:

> **Non-Hydro Capacity Impact:** Using the AURORAxmp model, approximately 35 GW of non-hydro renewable capacity additions are reflected in the CPP State, Regional, and Low-Gas Cases. These are added to maintain NERC's reserve margin reliability levels. The CPP State, Regional and Low-Gas Cases

very closely mirror the Reference (no CPP) Case, which demonstrates limited non-hydro energy growth levels. This is due to the lower cost of natural gas generation combined with the expired PTC and the reduced ITC for renewable energy resources. The additional renewable energy could strain ERSs and create additional planning and operational challenges. Chapter 4 on transmission adequacy provides more details on transmission reinforcement necessary to meet the EPA emission reduction targets as a result of increased wind and solar penetration levels.

Table 4 shows the IPM reference, CPP state, and CPP regional non-hydro renewable gigawatt capacity. Both models show slight renewable additions for the CPP cases due to no PTC and the assumptions of a 30 percent ITC for 2016 and a 10 percent ITC for 2017 and beyond. Renewable additions could increase accordingly if states set increased renewable targets or if other economic incentives are implemented. Additionally, if PTC and ITC are extended or increased, renewable additions could increase. NERC cannot count on such extensions.

Table 4: Non-Hydro Renewable GW Capacity – IPM Model

Modeled Cases	2016	2018	2020	2025	2030
Reference (No CPP)	96	103	116	126	135
CPP State	91	103	124	135	144
CPP Region	91	102	121	132	141

Resource Adequacy Scenario

An important element of this analysis is that reserve margin targets were maintained in order to serve as a reliability signal that more capacity is needed. Current approximate reserve margin targets of up to 20 percent were applied for each area and assumed to remain constant for the entire period assessed. However, given the changes to the generation mix, resource availability is likely to be negatively impacted. Uncertainty and variability of renewable resources (such as wind and solar) will need to be accounted for in establishing new target reserve margins. Higher forced-outage rates would also result in higher reserve margin targets, as each area would need to carry more reserve capacity to balance the uncertainty.

An important assumption of this analysis is that the reference margin levels, as reported for year 1 in the 2014 LTRA, are applied for each Assessment Area. Accordingly, reserve margin projections would trigger the AURORAxmp model to add capacity as needed to maintain resource adequacy. However, the likelihood of lower capacity factors resulting from the redispatching of resources could lead to higher forced-outage rates, which could ultimately result in higher reference margin levels to account for additional reserve capacity needed.

NERC ran a scenario to compare the 2014 LTRA Reference Case with the AURORAxmp results. Peak demand and resource projections (existing and Tier 1 capacity additions[20]) from the Reference Case were reduced by the retirements projected by the AURORAxmp (applying both state and regional implementation). The results indicated that certain Assessment Areas—particularly NPCC-US, TRE-ERCOT, and MISO—will face the most significant resource adequacy concerns in 2020, as shown in Figure 15.

[20] Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements.

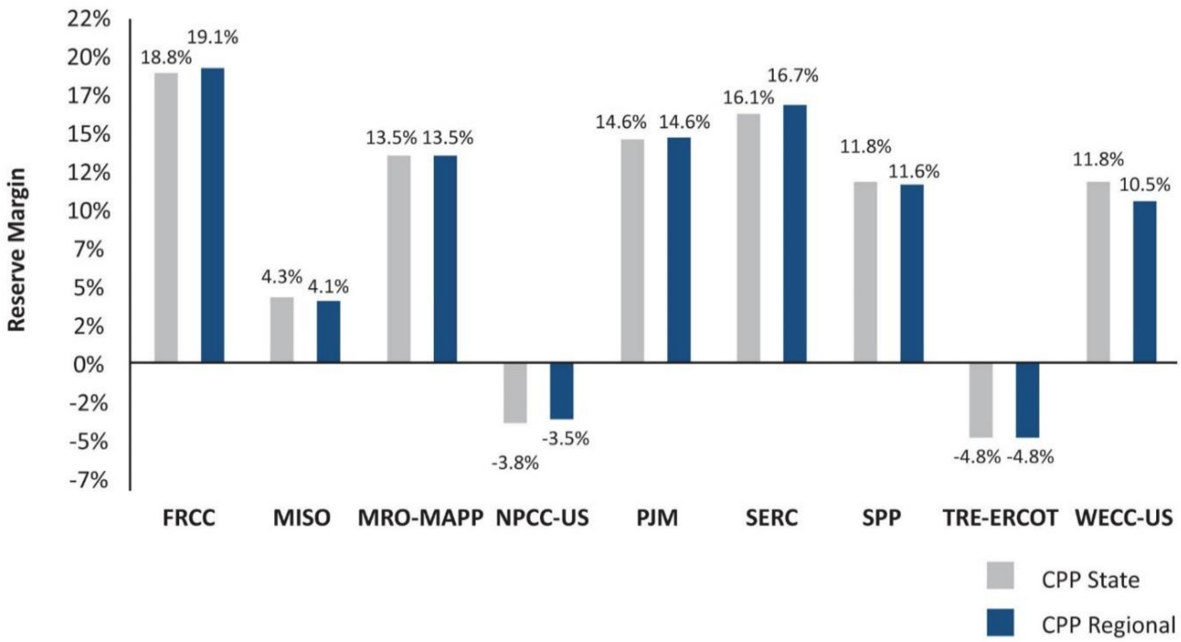

Figure 15: Impacts of CPP Cases on Regional Reserve Margins – 2020 Scenario

The capacity additions needed in these areas to maintain the current reference reserve margin levels align with these results. In ERCOT and NPCC-US, the AURORAxmp model indicates that over 11 GW and 7 GW, respectively, of capacity additions will be needed by 2020.

Power Transfer Changes across Major Power Market Areas

Based on NERC's modeling, the CPP will likely change the power flows in many major power areas. Since importing power is one option that can displace regional CO_2 emissions, similar to a transmission component of the building blocks, it will likely increase in many areas with high-reduction targets. In regional trading cases, areas with lower incremental CO_2 reduction options can displace higher-cost options in adjoining states or power pools. Overall, net transmission flow activity between regions is expected to increase by 19,230 MW under the state compliance plan (versus no CPP). Based on NERC's modeling, net transmission interchange flows were higher under a regional trading case, reaching 26,150 MW higher than the Reference Case. Table 5 and Figure 16 show the annual average transmission flows in megawatts for 20 major regions in the United States and Canada—average net MW imports (+) and net MW exports (-) from 2020 through 2030.

Table 5: Transmission Interchanges between 2020 and 2030—Average MW Imports (Positive) and Exports (Negative)

Area	MW Interchanges No CPP	MW Interchanges CPP State	MW Interchanges CPP Regional	Percent Flow Changes of the CPP State Case from a Reference (No CPP) Case	Percent Flow Changes of the CPP Regional Case from a Reference (No CPP) Case
CAN	-5,461	-13,699	-14,828	150.3	171.5
ISONE	2,595	2,935	2,949	13.1	13.6
NYISO	2,805	3,156	2,737	12.5	-2.4
PJM East	1,561	-5,167	-3,021	-430.9	-293.5
PJM West	-6,001	-2,125	-750	-64.6	-87.5
SERC North	1,524	-266	1,177	-117.5	-22.8
SERC East	1,745	3,742	2,394	114.5	37.2
SERC SE	-153	-390	-804	154.3	424.8
FRCC	2,726	3,238	2,489	18.8	-8.7
MISO North	-767	3,126	898	-507.4	-217.1
MISO Central	-8,159	-325	933	-96.0	-111.4
MISO South	6,472	3,424	4,301	-47.1	-33.5
MRO MAPP	-2,488	-1,675	-2,139	-32.6	-14.0
SPP	4,000	4,505	4,061	12.6	1.5
ERCOT	170	372	105	119.1	-37.8
WECC NW	-4,445	-5,220	-5,660	17.5	27.3
WECC CAL	8,185	7,005	10,809	-14.4	32.1
WECC SW	-2,571	-2,262	-3,538	-12.0	37.6
WECC RMPA	-1,379	72	-1,575	-105.2	14.2
MX	-360	-475	-540	31.8	49.7

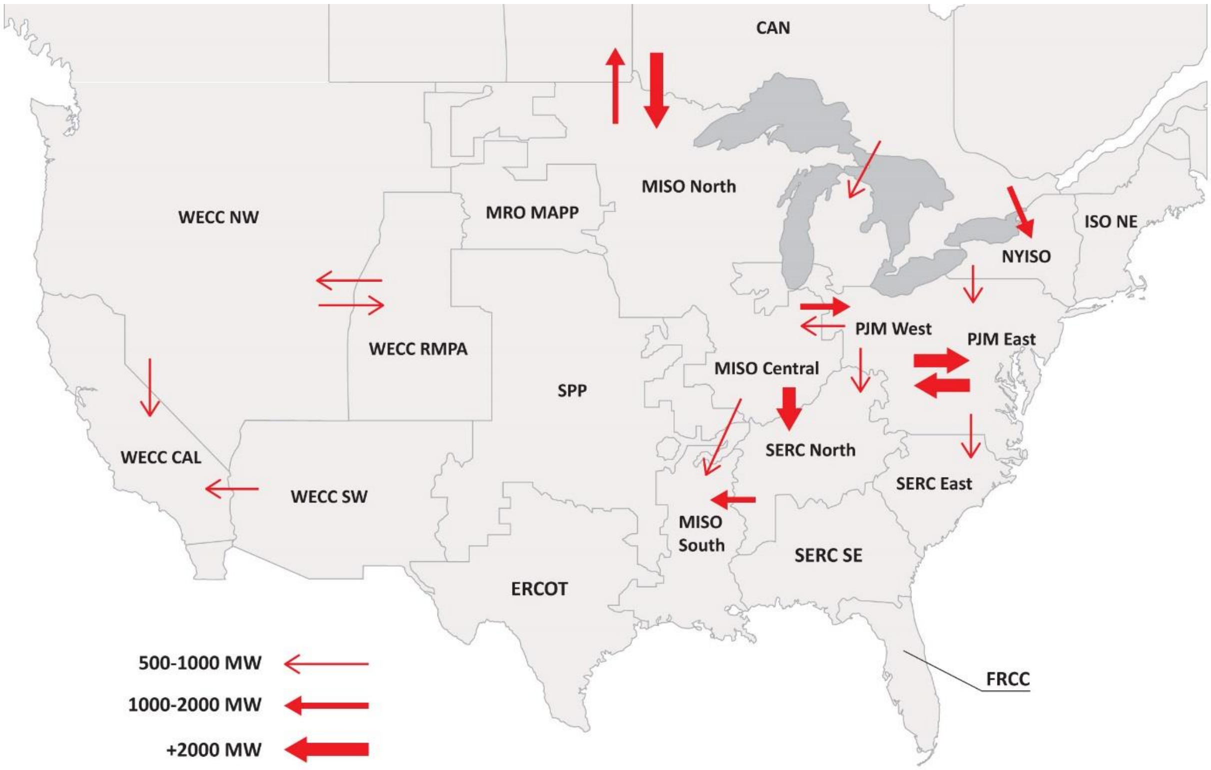

Figure 16: Change in Regional Power Transfers Comparing Reference Case to CPP State Case

Observations

Based on NERC's modeling, a significant adjustment of expected transmission flow occurs. Transmission flows that change in direction and magnitude as a result of a new generation dispatch require significant coordination and reliability analysis, particularly across transmission seams. As a result of CPP implementation in NERC's State and Regional Cases, NERC observed the following:

- Canada exports three times more power to the United States, mainly NPCC and MISO North.
- PJM-East shifts from being a net importer of power to a net exporter of power (mainly into PJM-West and NPCC) due to renewed competitiveness of generating units in RGGI states that were previously handicapped by RGGI CO_2 allowance prices (with carbon penalties in place in non-RGGI states as well).
- MISO-Central reduces power exports significantly due to cheaper generation imports from Canada into MISO-North.
- Power transfers increased into MISO South from MISO Central and SERC North.
- Major power flow changes unique to the CPP state scenario were also observed:
  - SERC North reduces imports and becomes a net exporter of power, mainly into SERC East.
  - WECC RMPA (CO and WY) reduces power exports from Colorado due to higher carbon penalties than in surrounding states.

Reliability Considerations

The change in the power flow, both in direction and magnitude, could present challenges in planning and operation of the BPS. In addition, timing implications could possibly impact reliability due to inadequate resources in certain areas. These changes in power transfers between areas require extensive power system studies and planning to ensure existing transmission lines are capable of such transfers. In addition, dynamic reactive power resources may be needed to maintain voltage stability to support normal operation of the system as well as to ensure the system's resiliency against contingencies. Dynamic stability also needs to be taken into consideration with the addition of new resources and requisite transmission lines, especially in cases where generation is farther away from demand centers than they are currently. The location of new resources could be impacted based on the proximity of the resources to natural gas pipelines as well as their proximity to wind and solar-rich areas. Although all of the additions and retirements will not happen simultaneously, protection systems should be studied, tested, and coordinated to ensure reliable operation of the BPS. As mentioned in NERC's 2014LTRA, necessary maintenance and upgrades as a result of aging electric infrastructure can also introduce additional challenges as the resource mix change accelerates due to the CPP.

The power flow changes represented in NERC's analysis demonstrate the continued evolution of resource deployment and use of renewable and natural gas generation. Over the next several years, these resource changes will require more transmission to integrate the new resources, meet increasing electricity demand, and enable exports and imports. Consistent with NERC's conclusion on its overall assessments, power flow changes represent a significant planning and operational challenge. Sufficient time and coordination is needed to determine region-specific solutions.

Conclusions

- The AURORAxmp and IPM models show similar trends between 2020 and 2030 for coal unit retirements and natural gas unit additions. Although the timing of retirements and additions differs between models, the overall level of natural gas additions and coal capacity retirements is roughly equal between 2016 and 2030.
- The AURORAxmp model determines that some coal units will remain operational but at much lower load factors. These units (14–22 GW) are considered "at risk" and may retire based on resource planning outside of the model results.
- State and Regional Cases produce similar results in terms of the amount of capacity that was added and retired. This is partly due to the fact that the models assumed trading of carbon emissions would occur in regional groupings across typical RTO/ISO and contiguous regions. More optimization among non-contiguous regions could potentially produce different regional results not contemplated in NERC modeling inputs (which assume trading based on physical power flows). Additionally, thermal transmission line capabilities in both models limit the transfer of power between regions at the same level in both State and Regional Cases. Additional transmission would be necessary to optimize trading capabilities among regions. Whereas carbon shadow prices among states indicate differing economic values, NERC's model assumes trading would occur using physical power flows. A final rule by the EPA could contemplate different trading mechanisms to capture the value of carbon trading across regions.
- The shift in resources from both a capacity standpoint and resource utilization (energy dispatch) standpoint indicate a need for transmission and gas infrastructure additions to maintain BPS reliability. Chapter 5 discusses infrastructure needs and lead times in more detail.

Chapter 4 – Steady-State Power System Analysis

The proposed CPP introduces resource adequacy concerns as identified in Chapter 3, but it also presents the potential new challenge of industry needing to ensure that transmission facilities are in place to integrate new resources—in addition to adjustments—necessary to address new interchanges. Accommodating necessary transmission line additions and upgrades may represent significant reliability challenges due to extensive planning and construction requirements. The proposed time period for CPP compliance adds additional challenges from a reliability perspective. New dispatch patterns will require comprehensive assessments to identify reliability impacts resulting from the changes to power flows. With additional variable resources projected, along with the retirements of baseload capacity, maintaining ERSs will become a priority. The characteristics that comprise ERSs must be considered in resource planning, specifically load and resource balancing, ramping capability, voltage support, and frequency support.

This chapter assesses the North American BPS's ability to accommodate the accelerated change in generation mix, transmission facility requirements, and reactive power support needs resulting from the implementation of the proposed CPP. The lead times necessary for planning, permitting, and construction of generation and transmission facilities are also discussed and are examined further in Chapter 5.

Power Flow Cases and Evaluation Approach

The power flow case in this assessment examines summer loading conditions for 2020 to align with the initial implementation of the proposed CPP. The Eastern and Western Interconnection planning base cases for this study were prepared by the Eastern Interconnection Reliability Assessment Group's (ERAG) Multiregional Modeling Working Group (MMWG) [21] and WECC's Modeling Working Group (MWG)[22] and were used for the Reference Case.[23] State and regional results from the AURORAxmp model, as described in Chapter 3, were used as input for this evaluation to identify generation retirements and additions for both the Eastern and Western Interconnections (CPP State Case and CPP Regional Case).[24] The projected resource availability, load, and losses in the Eastern and Western Interconnections are provided in Figure 17. ERCOT performed a separate study[25] that examines the ERCOT Interconnection on the implications of the CPP along with other environmental regulations, which is summarized in Chapter 6.

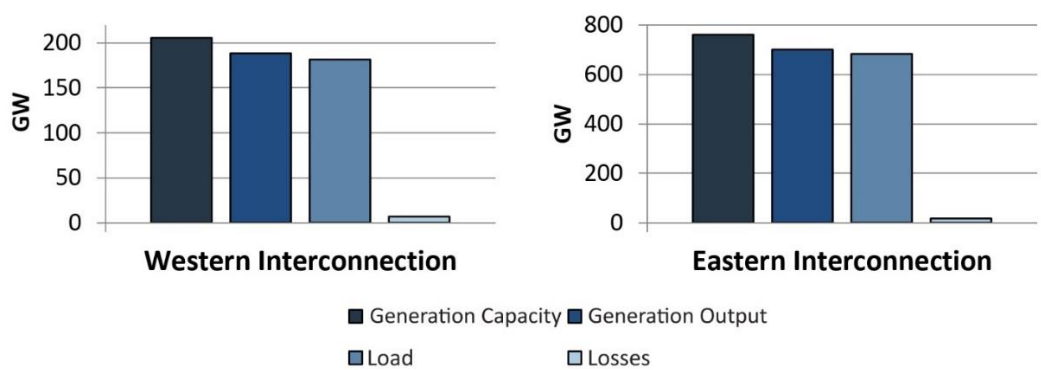

Figure 17: Generation Capacity, Load, and Losses in Eastern and Western Interconnections

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[21] Eastern Interconnection Modeling Working Group.

[22] WECC Modeling Working Group.

[23] Transmission and generation additions and retirements planned by 2020 are reflected in these cases. Both models incorporate impacts of existing regulations.

[24] NERC conducted power flow analyses for both the CPP State Case and the CPP Regional Case. However, from a capacity perspective, the results of the dispatch model (AURORAxmp) were very close. Therefore, the figures and maps included in this chapter are based on the CPP State Case from the AURORAxmp model output.

[25] Impacts of Environmental Regulations in the ERCOT Region.

This model was created using the following input to identify areas of potential generation and transmission constraints as a result of capacity retirements and additions:

- Type of generation
- Location of capacity retirements
- Location of gas-fired capacity additions (proximity to existing sites (brownfields), existing transmission facilities, and existing gas pipelines)
- Location of new wind and solar resources (proximity to areas with abundant wind and sunlight)
- Location of existing reactive power resources to support voltage requirements

Transmission facilities were added to the model to tie in greenfield unit locations to transfer the new generation to the point of interconnection.

Generation Retirements

Generation retirements shown in Figure 18 include announced generation retirements due to other regulations and end of life of the units, in addition to the projected retirements due to the proposed CPP. Texas, California, New York, and Massachusetts are projected to have the largest natural gas resources retirements, while Kentucky, Alabama, Georgia, and Indiana are projected to retire the largest amounts of coal-fired generation among the lower 48 states.

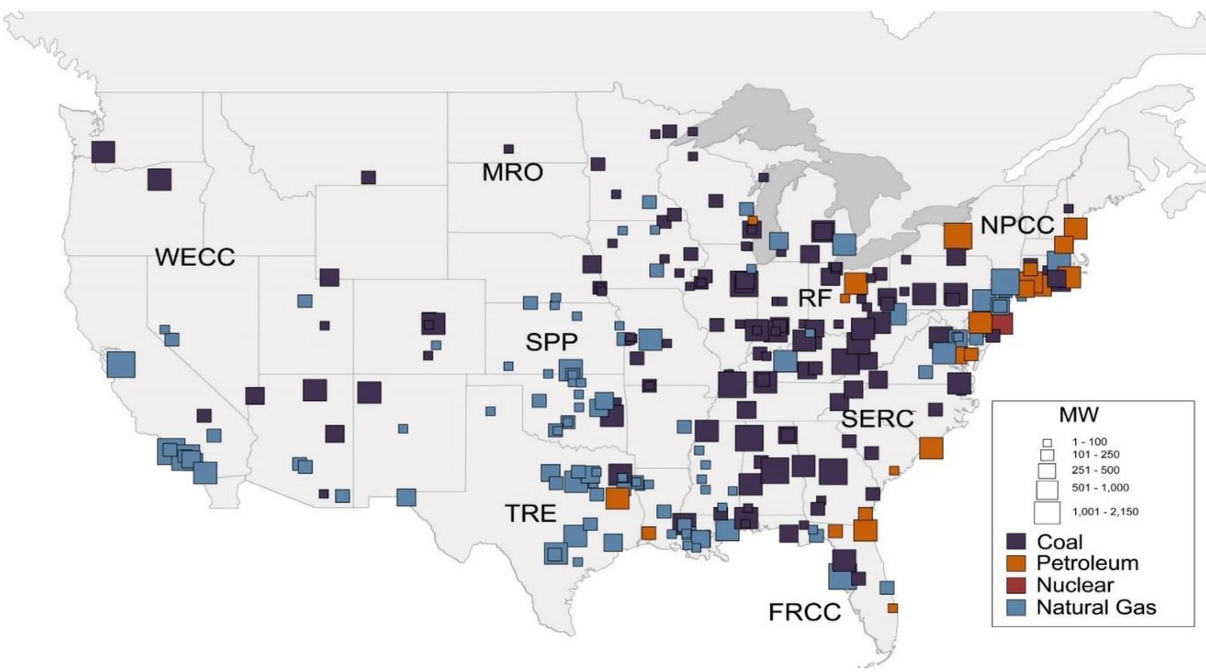

Figure 18: Generation Retirements by Fuel Type and Size[26]

[26] Maps created using Velocity Suite, ABB Enterprise Software.

Generation Additions

In order to compensate for the retirement of generating units, additional generation resources will be required to serve load in the Eastern and Western Interconnections. With the changes in the resource mix—mostly the shift from coal to natural gas and increased penetration of renewable resources—some assumptions were required to approximate the location of these additions. The location of new generation was selected based on a computer model algorithm that used the following attributes to determine logical power plant sites:

- Proximity to the site of the retired unit (brownfield)
- Proximity to available resources (natural gas units located close to gas pipelines, wind resources close to wind-rich areas, etc.)
- Proximity to existing high-voltage transmission substations and other transmission facilities

From the total capacity additions in the Eastern and Western Interconnections, 23 percent of the total generation capacity additions were positioned on the brownfield sites, and the remaining 77 percent require new sites. The greenfield sites were selected to maximize the use of existing transmission facilities.

Generation additions shown in Figure 19 include announced generation additions in addition to the generating resources required to serve load while maintaining planning reserve margins. The majority of generating unit additions, analogous to the retirement of coal-fired resources, are natural gas and renewable. Pennsylvania, Texas, Florida, and California are projected to add the largest amounts of gas-fired generation among the 48 contiguous states.

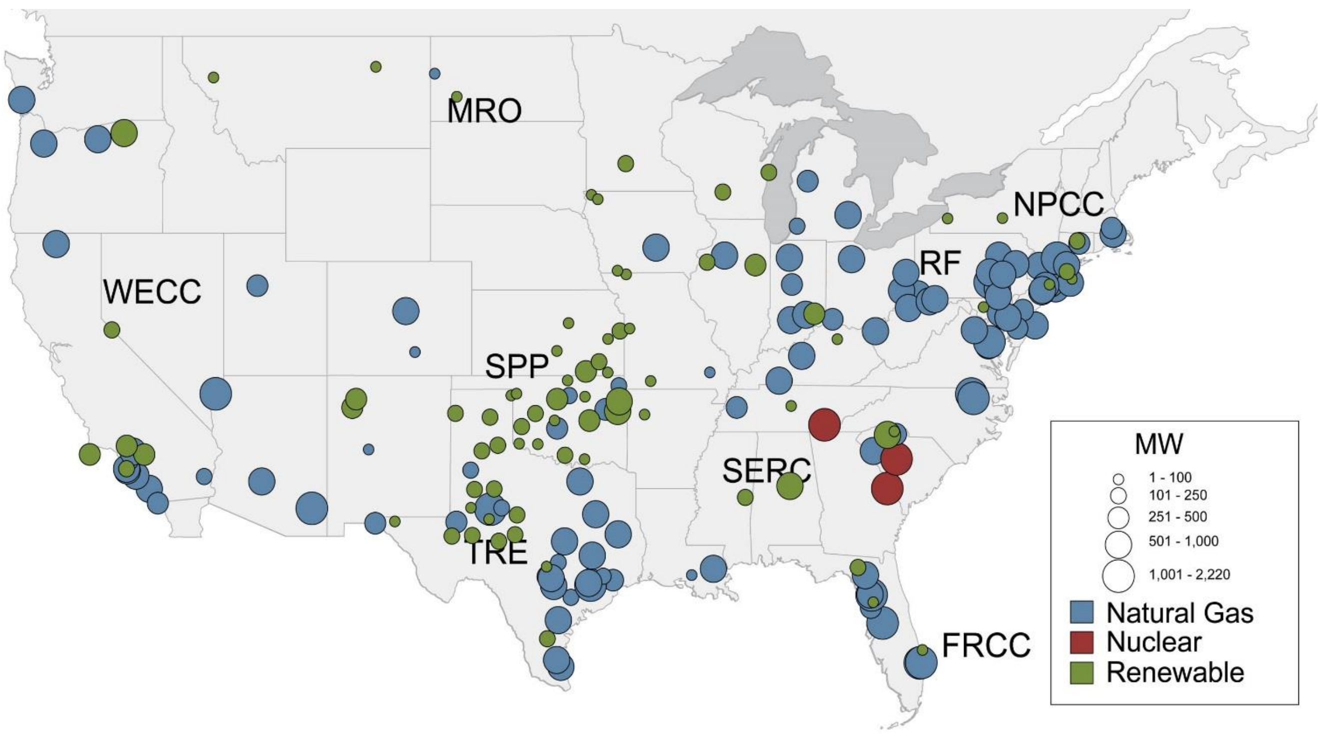

Figure 19: Generation Additions by Fuel Type and Size[27]

[27] TRE's natural gas and renewable addition locations are based on estimates only.

Transmission Addition Requirements

Following the determination of locations for the new generating units, the most appropriate transmission voltage levels (230 kV, 345 kV, or 500 kV) were selected in order to accommodate the amount of added generation while minimizing the amount of power transfer losses. The selection criteria of new transmission facilities included economic factors such as a higher cost of increased voltage facilities.

To address system contingencies, additional transmission lines and facilities—as well as upgrades to existing lines and facilities—may be required. This would be necessary to ensure stability following a system event on the BPS.[28] Figure 20 shows transmission addition requirements as a result of NERC analysis. Appendix B provides more information on methods and requirements for system stability and security used in this study.

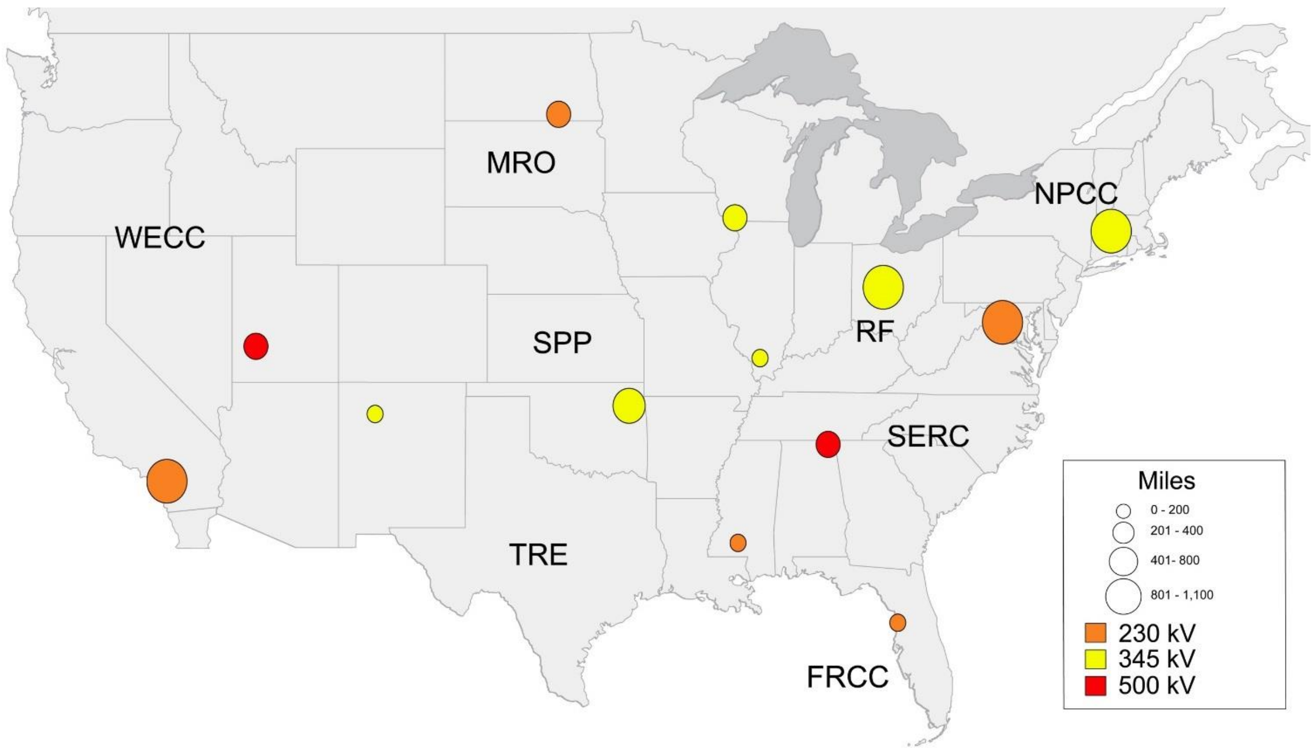

Figure 20: Transmission Line Additions in Eastern and Western Interconnections by Voltage Class and Length

[28] NERC did not conduct a contingency analysis for its transmission adequacy analysis. However, contingency planning is required, and additional transmission facilities (beyond what is identified in NERC's analysis) may be needed to satisfy reliability requirements. Therefore, NERC considers its results to be on the "low end" of transmission needs compared to what would be needed to satisfy reliability and contingency analysis requirements.

Reactive Power

Where power is transferred over longer distances to the point of interconnection, higher amounts of reactive resources are required to maintain voltage stability and voltage support from generators, especially renewable resources (see Figure 21). With the accelerated change in the resource mix, additional transmission resources (such as shunt capacitors, synchronous condensers, SVCs, STATCOMs, etc.) will be needed to maintain adequate voltage levels.[29]

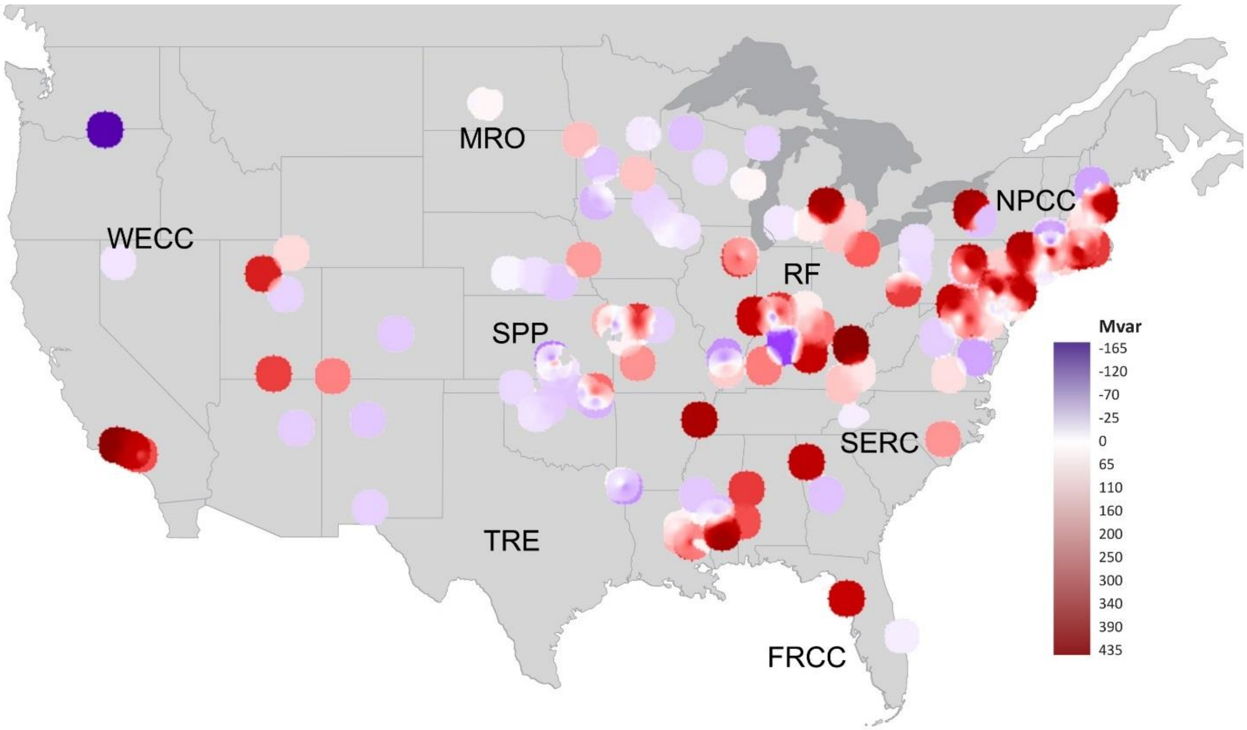

Figure 21: Reactive Power Support Needed in Eastern and Western Interconnections

[29] Reactive power losses of generator step-up transformers (GSUs) were modeled by reducing generating unit reactive power output.

Lead Time and Timing Implications

Generating unit additions and the accelerated change in resource mix will require permitting, planning, and construction of other facilities to support the voltage profile as well as transmission of power to the point of interconnection. Lead time for the delivery of each facility (generating plant, tie-in substation, and transmission) depends on many factors that should be individually evaluated for each type of addition, such as:

- Permitting process and the project's social acceptance
- Typical facility capacity, location, and interconnection voltage level
- Manufacturing capability and delivery lead time
- Construction capability and duration

The average lead time per facility type (Chapter 5 discusses these lead times in more detail) is used to estimate the required power timeline needed to support the load in the Eastern and Western Interconnections. For added generation capacity, only approximately 20 percent of the capacity required will be available by 2020. The generation and transmission additions and upgrades necessary to fulfill the capacity requirements, as indicated in the AURORAxmp results, would not be completed until 2031 (Figure 22). The timeline may vary with consideration of the following assumptions and factors:

- The model assumes that planning and permitting for new facilities will begin in 2015.
- A greater number of transmission facilities would be required if contingency analysis were considered.

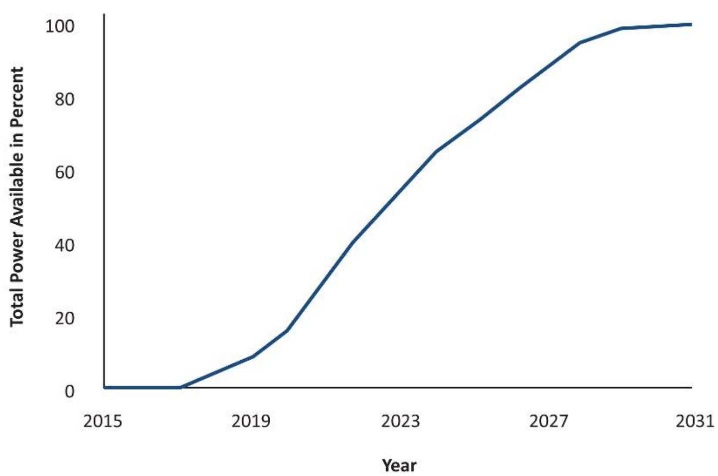

Figure 22: Total Power Available With Projected Facilities Required

Conclusions

NERC's modeling of the CPP yielded approximately 43 GW of additional retirements by 2020 (based on NERC's CPP State Case). As a result of these retirements, generation capacity replacement is required to serve existing and forecast load. The accelerated change in generation mix by fuel type and location would introduce challenges associated with constructing transmission facilities needed in order to transfer power to a point of interconnection. The transmission projects are comprised of engineering, siting, permitting, and constructing, which are highly dependent on geography and right-of-way. The change in the flow of power and area transfer interchanges should be extensively studied, and the need for transmission facility additions or upgrades should be identified. These efforts will all require more in-depth and system-specific analysis, which includes evaluating transmission adequacy under various contingency scenarios, examining voltage and transient stability caused by system disturbances, and determining interchange power transfer capabilities between systems.

The identified transmission needs are representative of a solution set that corresponds to NERC's resource adequacy analysis in Chapter 3 (therefore, the same assumptions apply for this analysis). In terms of timing, NERC's analysis identified transmission needs that would require approximately 16 years to complete. However, to be clear, NERC is not advocating that the CPP be delayed 16 years. While NERC recognizes that this specific implementation may not materialize, it is clear from the analysis that additional transmission will be needed to support the new generation mix. Because of the uncertainties associated with the proposed CPP rule, NERC cannot make a specific determination of timing; however, meeting a 2020 interim target date that requires transmission as part of the solution may not be feasible.

Additional analysis in the following chapter provides details on infrastructure lead times.

Chapter 5 – Timing Implications

Electric Infrastructure Upgrade Timing Implications

Electric transmission and resource adequacy planning is a lengthy and rigorous process, mainly due to the implication of the investments and need to carefully coordinate system improvements throughout an area. In anticipation of long lead times for developing new transmission, transmission planners and resource planners plan the system over a 10-to-15-year time horizon to identify transmission constraints, resource constraints, and other reliability concerns to ensure the system is compliant with all applicable NERC Reliability Standards and resilient enough to maintain reliability.

As part of NERC's CPP Phase I study, NERC requested information from industry on new generation and transmission facility construction lead times. The results represent the perspectives from 110 different transmission and generation companies on timing requirements (in months) for additional new transmission and generation capacity. Naturally, the timing needs are highly dependent on the scope of a project, length of transmission, and geography. Entities in different regions of the country face different challenges in building new transmission and generating facilities. The results report the average time in months necessary to complete each phase. Results are based on recent historical performance (i.e., projects in service within the last two to three years) and any future projects with known schedules.

Lead Times for Generation Construction

NERC requested information on combined-cycle gas turbines (CCGTs), which consist of combustion turbines (CTs) and steam turbines (STs) of three different sizes; wind turbines based on a typical plant size; and utility-scale solar projects. The information NERC received from industry was based on commercially available generators by fuel type and capacity class.

The information request only took into consideration lead time associated with constructing a new generator. NERC considered every phase it takes to build a power plant from conception to inception. While the amount of time to construct any given project is unique and any number of local, regional, or federal factors could influence the project timeline, these lead times provide a relative indication for policy makers to better understand lead times associated with specific solution sets. Table 6 shows the commensurate timelines for potential capacity additions.

Table 6: Combined-Cycle Generation Construction Timeline in Months			
Turbine Type	**2 Combustion Turbines and 1 Steam Turbine**	**3 Combustion Turbines and 1 Steam Turbine**	**4 Combustion Turbines and 1 Steam Turbine**
Approval in Planning Stage/Interconnection Agreement	17	18	16
Permitting	17	17	16
Construction	30	30	32
Total	**64**	**64**	**64**
Gas-Fired Generation Construction Timeline In Months (Plant Size GT)			
Size (MW)	**200–500**	**501–700**	**701–800**
Approval in Planning Stage/Interconnection Agreement	15	15	16
Permitting	16	15	16
Construction	23	25	26
Total	**53**	**55**	**58**
Coal Generator (Plant Size) Timeline in Months			
Generator (MW)	**200–500**	**501–700**	**701–800**
Extended outages for unit retrofit to improve heat rate	8	8	7
Wind Generation (Plant Size) Timeline in Months			
Generator (MW)	**0–50**	**51–100**	**101–150**
Approval in Planning Stage/Interconnection Agreement	16	16	16
Permitting	13	12	12
Construction	9	12	12
Total	**37**	**40**	**40**
Utility-Scale Solar Generation (Plant Size) Timeline in Months			
Generator (MW)	**0–50**	**51–100**	**101–150**
Approval in Planning Stage/Interconnection Agreement	13	14	15
Permitting	9	10	11
Construction	9	13	17
Total	**31**	**37**	**42**

Based on the responses, it historically takes an average of 64 months, or just over five years, to complete all necessary planning, permitting, and construction for a new CCGT facility. Size of the generation units does not appear to be a major factor. The average for a utility-scale solar generation project is 36 months. The average for wind is 39 months. The proposed CPP target implementation dates raise concerns when compared to generation facility construction—particularly CCGT—and lead times needed to replace retiring units and respond to increasing electricity demand.

Lead Times for Electric Transmission Projects

Transmission companies must plan upgrades to transmission facilities on the BPS several years in advance to accommodate necessary lead times. In the transmission expansion planning process, transmission planners conduct ongoing power flow analyses to identify thermal constraints on the BPS and develop solutions. Any changes in load or generation in a given area may result in changes to the power flow on those respective transmission lines—particularly retirement and addition of new generation. Any transmission lines exceeding their conductor ratings are further analyzed to ascertain possible solutions, which could include reconductoring or building new transmission facilities. Depending on the complexity, severity, and urgency of the transmission issue, this process could take several years to complete. The request for electric transmission projects was delineated for transmission lines less than 100 miles and transmission lines greater than 100 miles. NERC also sought information on line construction and substation construction considerations, whether the line is in an urban setting, and if the line crosses interstate lines—all of which could increase the amount of time it takes to complete the project.

The results NERC received are from Transmission Owners who had transmission projects that went into service within the last two to three years or who have plans to build new facilities in their long-term study plans. The results are shown in Table 7.

Table 7: Electric Transmission Facility Construction Timeline in Months						
Line Length		**100 kV–199 kV**	**200 kV–299 kV**	**300 kV–399 kV**	**400 kV DC**	**500 kV–599 kV**
1–100 miles	Surveying	8	9	10	9	19
	Land & Right-of-Way Acquisition	15	15	17	14	17
	Permitting	13	13	15	7	20
	Construction Line (New)	19	21	22	24	41
	Construction Line (Reconductoring)	15	23	20	26	34
	Construction Substation (New)	18	26	19	24	32
	Construction Substation (Upgrade)	12	16	16	23	24
	Additional months needed for urban setting	9	8	13	14	9
	Additional months needed for interstate versus intrastate	6	10	11	6	14
>100 miles	Surveying	10	11	12	10	12
	Land & Right of Way Acquisition	26	21	24	20	31
	Permitting	20	21	26	18	32
	Construction Line (New)	38	34	39	44	79
	Construction Line (Reconductoring)	24	28	36	49	65
	Construction Substation (New)	17	20	20	24	32
	Construction Substation (Upgrade)	12	15	16	23	24
	Additional months needed for urban setting	9	10	19	27	18
	Additional months needed for interstate versus intrastate	6	9	12	6	14

The results indicate that it takes several years to complete most projects. Although there is some overlap between right-of-way acquisition and permitting, the majority of each project's timeline is taken up during the construction phase. An example would be a reconductoring of a rural 100 mile, 230 kV transmission line averaging 81 months, or just under seven years. It can take up to 15 years to build a new 500 kV line from planning to energization. The 15-year timeline to build a 500 kV line assumes some work can be accomplished in parallel, such as constructing a substation when constructing a new line.

Lead Times for Natural Gas Pipeline Projects

The process of siting, constructing, and installing additional pipeline capacity is complex and requires sufficient lead time in order for necessary studies, approvals, and construction to take place. Though the complications can be considerable for each pipeline project, their approval process is very much the same for enhancements that occur on the system--whether the project is a new pipeline, converting an oil pipeline to a natural gas pipeline, looping a parallel pipeline, or upgrading facilities along an existing route.[30] Each project can be segmented into the stages shown in Figure 23.

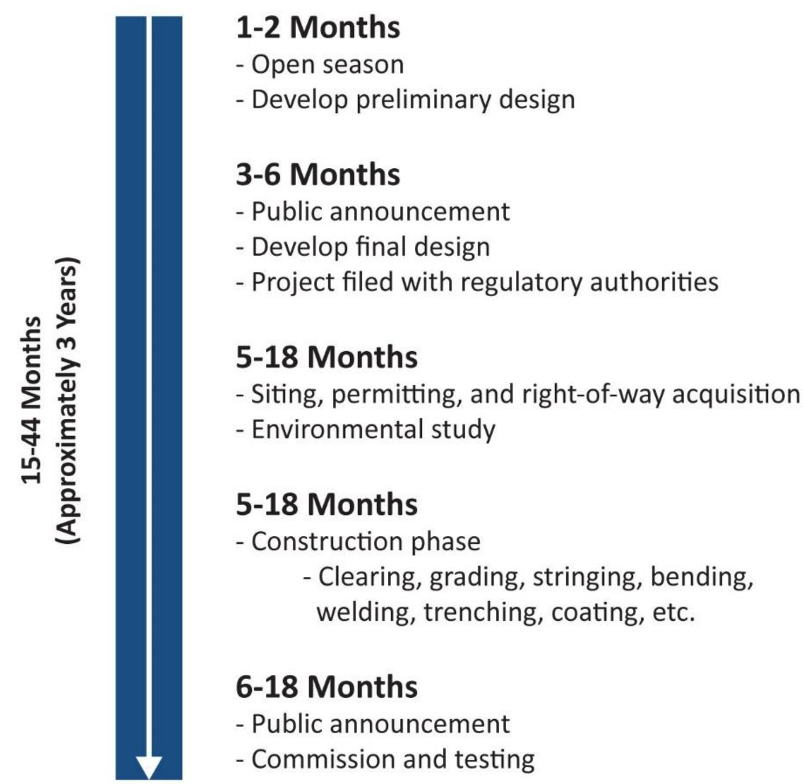

Figure 23: Timeline for Natural Gas Pipeline Projects

A natural gas pipeline project requires approximately three years from conception to a finished product that has been placed into service. The lead times shown above represent a 20-mile project that crosses state boundaries, does not include resubmittals, requires the average time to obtain all necessary permitting and clearance, and does not accrue major construction delays. Additional time will be required if the project is larger and complications arise during construction.

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[30] Process and Timeline for Development of Additional Natural Gas Pipeline Infrastructure.

Constructing new natural gas pipeline can also create operational challenges. As capacity needs for gas pipelines increase, enhancements to the pipeline system are likely to occur in the form of increasing pipeline sizes or diameters. Therefore, as pipelines are constructed, existing pipelines may need to come out of service to accommodate the upgrade. Because these outages will likely occur in the shoulder and summer seasons when use of gas-fired generation is expected to increase, this can create some short-term issues and require tight coordination between the gas and electric industries.

Conclusions

It is evident, based on the feedback from NERC's information request, that reinforcing the system to comply with the CPP would present challenges. Based on the 6-to-15-year projected construction timeline to build various transmission facilities, as well as approximately five years on average to build a new NGCC, timing issues pose challenges to meeting the proposed CPP targets.

To support the significant amount of new gas-fired generation expected over the next several years, new pipeline capacity will be needed. Based on NERC's analysis, construction of even small interstate pipeline projects can require three years to complete.

Chapter 6 – NERC's Assessment on Analysis Conducted by Selected NERC Regions and ISO/RTOs

As part of its Phase I study, NERC has reviewed publicly available industry analysis directly related to CPP compliance. The studies NERC reviewed are not all-inclusive; they represent a cross section of Regional Entities and ISO/RTOs that face unique dispositions and challenges with existing system infrastructure. ERCOT, MISO, PJM, SPP, and WECC conducted and reviewed the studies; each study examined the impacts from the proposed CPP. These studies were conducted by industry stakeholders, and the information they contain is not the result of a NERC analysis. The studies are linked in Table 8 and summarized below.

Table 8: CPP-Related Studies

Reliability Authority	Reliability Role (Major)	Link to Study
ERCOT	Transmission Planner and Operator, Planning and Reliability Coordinator	*Impacts of Environmental Regulations in the ERCOT Region*: http://www.ercot.com/content/news/presentations/2014/Impacts%20of%20Environmental%20Regulations%20in%20the%20ERCOT%20Region.pdf
MISO	Transmission Planner and Operator, Planning and Reliability Coordinator	*Analysis of EPA's Proposal to Reduce CO_2 Emissions from Existing Electric Generating Units*: https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/AnalysisofEPAsProposaltoReduceCO_2EmissionsfromExistingElectricGeneratingUnits.pdf
PJM	Transmission Planner and Operator, Planning and Reliability Coordinator	*PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal:* http://www.pjm.com/~/media/4CDA71CBEC864593BC11E7F81241E019.ashx
SPP	Transmission Planner and Operator, Planning and Reliability Coordinator	*SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan:* http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf
WECC	Regional Reliability Organization (Regional Entity Responsible for Enforcing NERC Standards)	*EPA Clan Power Plan: Phase I – Preliminary Technical Report* by WECC Staff: https://www.wecc.biz/Reliability/140912_EPA-111%28d%29_PhaseI_Tech-Final.pdf

Observations

In its assessment of the individual analyses performed by five NERC Regional Entities and RTO/ISOs, NERC observed the following:

- The studies reflect shifts from coal-fired generating units to natural-gas-fired generating units and renewable resources in concurrence with the results from the AURORAxmp and IPM models.
- Findings generally differ among areas as well as within zones of those areas. This is largely spurred by a resource mix that is widely different across the country and different motivations from a policy and state perspective.
- These analyses did not assume changes in their neighboring systems due to the significant complexity associated with the flexibility within the proposed CPP.
- The studies are inconclusive, given that a final rule has not yet been issued and there are significant unknowns.
- The studies indicate generally higher electricity production costs, which drives the significant resource mix changes from both a capacity and energy perspective, consistent with NERC's analysis.
- The timing of the CPP implementation is addressed in all the studies, but in varying degrees. Some of the studies raised concerns, but others implied that compliance will not be difficult to achieve.
- The majority of studies addressed the timing of retirement announcements. This could create compounded issues if significant retirements occur simultaneously. This is a major challenge, particularly in market areas where established long-term planning horizons conflict with the plans that will be developed by states.

NERC Conclusions

As plans are being developed, it is important that reliability authorities continue to conduct the reliability analysis needed to plan and operate the BPS as required by NERC Reliability Standards.

Given the focus on state and regional variability, concerns with timing of retirement announcements, and resource shifts, a reliability assurance mechanism could further assist in addressing issues, including those that might arise across operating boundaries.

ERCOT

Overview

ERCOT is the independent organization established by the Texas Legislature to be responsible for the reliable operations and planning of the electric grid for the ERCOT Interconnection. Several proposed or recently finalized U.S. EPA regulations could have an impact on grid reliability in ERCOT. These rules include the MATS, the Cross-State Air Pollution Rule (CSAPR), the Regional Haze program, the Cooling Water Intake Structures rule, the Steam Electric Effluent Limitation Guidelines (ELG) rule, the Coal Combustion Residuals (CCR) Disposal rule, and the Clean Power Plan. ERCOT conducted studies to assess the individual and cumulative impact of these regulations on the ERCOT Interconnection.

Modeling and Input Assumptions

ERCOT undertook two study efforts. First, a survey was distributed to fossil-fuel-fired generators on the impacts of relevant environmental regulations. The survey asked questions about plans for unit retirements, suspended operations, and planned modifications to comply with environmental regulations. No resource owners responded with plans for retirements or suspended operations except for any previously announced plan to mothball. Second, ERCOT conducted a modeling analysis of the impacts of CSAPR, the Regional Haze program, and the CPP on generation resources and energy costs in ERCOT. The study uses Energy Examplar PLEXOS Integrated Energy Model mixed integer programming to model the power sector. In this study, ERCOT used the long-term modeling capability in PLEXOS to estimate unit retirements and capacity additions over the 2015 to 2029 time frame.

ERCOT conducted six scenarios that included a base case and five scenarios that reflected impacts considering CSAPR, Regional Haze, and CPP. The scenario analysis conducted by ERCOT was not meant to be a comprehensive study of all regulatory impacts and potential compliance pathways.

Resource Adequacy Findings

The implementation of the proposed CPP will cause a shift in the resource mix due to the retirement of higher-emitting CO_2 units being displaced by lower-emitting CO_2 units. The higher-emitting units are predominantly coal-fired generation, which is being replaced by natural gas and renewable generation. Coal units are the most affected by environmental regulations. These results indicate that not taking into account the CPP, 3,000 to 8,500 MW of coal-fired capacity in ERCOT can be considered to have a moderate to high risk of retirement—due primarily to the costs of the EPA's proposed requirements for the Regional Haze program. The implementation and regulatory timeline of the CPP will impact decisions that resource owners make about whether to retrofit or retire impacted units. Additionally, the CPP itself may cause unit retirements, due to the need to meet stringent CO_2 emission limits on a state-wide basis. ERCOT's modeling analysis suggests that the CPP, in combination with the other regulations, will result in the retirement of up to 8,700 MW of coal-fired capacity.

The CPP will also result in increased wholesale and consumer energy costs in ERCOT. Based on ERCOT's analysis, energy costs for consumers may increase by up to 20 percent in 2020, without accounting for the associated costs of transmission upgrades, higher natural gas prices caused by increased gas demand, procurement of additional ancillary services, energy efficiency investments, capital costs of new capacity, and other costs associated with the retirement or decreased operation of coal-fired capacity in ERCOT.

Transmission Adequacy Findings

It takes at least five years for a new major transmission project to be planned, routed, approved, and constructed in ERCOT. As such, in order for major transmission constraints to be addressed in a timely fashion, planning must occur at least five years in advance. The load growth in the ERCOT urban centers like Houston, Austin, and Dallas results in the need for new transmission infrastructure. As the units that are at risk of retirement from the proposed rule are located near these load centers, future transmission needs would be increased or accelerated by the likely retirements. For example, a new 345 kV transmission line is currently planned to be in place by 2018 to serve customers in the Houston area. Long-term studies indicate a potential need for further upgrades in the mid-2020s. The retirement of generation resources within the Houston area prior to 2018 would likely result in grid reliability issues prior to completion of the proposed reinforcement project. Therefore, the need for this new transmission project would be accelerated to the near-term horizon (one to six years) from the long-term horizon (six to 15 years).

Conclusions and Key Findings

- Based on the study results, the Regional Haze requirements and the CPP will have significant impacts on the planning and operation of the ERCOT grid. Both are likely to result in the retirement of coal-fired capacity in ERCOT.
- Currently, resource owners are required to notify ERCOT no less than 90 days prior to the date that the unit is retired or mothballed. Given the competitiveness of the ERCOT market and the current uncertainty surrounding environmental regulations, it is unlikely that generators would notify ERCOT of potential retirements or unit suspensions before the minimum notification deadline. If ERCOT does not receive early notification of these retirements, and if multiple unit retirements occur within a short time frame, there could be periods of reduced system-wide resource adequacy and localized transmission reliability issues due to the loss of generation resources in and around major urban centers.
- The loss of reliability services (i.e., ERSs) previously provided by units that are now retiring will strain ERCOT's ability to integrate new intermittent renewable generation resources. The need to maintain operational reliability (i.e., sufficient ramping capability) could require the curtailment of renewable generation resources. This would limit or delay the integration of renewable resources, leading to a delay in achieving compliance with the proposed CPP limits.
- Complying with these regulations in the near term could lead to concurrent unit outages and increased seasonal mothballing of capacity. If these changes result in impacts to grid reliability and transmission constraints, and there is not sufficient time to mitigate these issues, there could be challenges to ERCOT's management of the grid.

MISO

Overview

MISO undertook a study to help stakeholders understand the impact of the EPA proposal to reduce CO_2 emissions from existing fossil-fired generation. MISO's analysis is not exhaustive in its assessment of the impact of the rule across MISO's footprint, but is an initial look at the potential impacts to help stakeholders prepare comments to the EPA. MISO's analysis is independent; MISO does not make recommendations on what compliance solutions are best: those decisions will need to be made by regulating entities and state officials once a final rule is in effect.

Modeling and Input Assumptions

MISO modeled the compliance costs of CO_2 emission reductions achieved through the application of the building blocks as outlined in the EPA proposal. The building blocks include making efficiency upgrades at coal units and increasing the use of combined-cycle gas units, among other things. MISO also evaluated alternative compliance options to those outlined in the building blocks. MISO modeled nearly 1,300 different combinations of a range of policy and economic conditions to calculate compliance costs and also modeled actions beyond the scope of the EPA's building blocks. Modeled sensitivities included: a range of coal unit retirements, renewable portfolio standards, energy efficiency levels, nuclear unit retirements, carbon costs, gas prices, and demand and energy growth rates.

Resource Adequacy Findings

According to MISO's analysis, the most cost-effective means of complying with EPA's rule may be to retire more coal generation than what is already projected to retire due to the EPA's MATS regulation. Specifically, MISO found that the EPA's proposal could put up to an additional 14 GW of coal capacity at risk of retirement (in addition to the 12.6 GW of capacity already projected to retire).

Conclusions and Key Findings

- MISO's review indicates that the rule's "interim performance period" will require significant CO_2 cuts to be made in the 2020 time frame. This is based on the need for immediate action to meet the 10-year average identified in the proposed rule.
- It is possible that state plans will not be finalized until the 2018–19 time frame, leaving little time for decisions on infrastructure changes before 2020. MISO is concerned that this short timeline will not allow for cost-effective, long-term planning to occur.
- If coal plant retirements are part of the compliance strategy for 2020, capacity additions in a two-year window may be difficult. MISO's experience is that new gas plant construction typically requires a longer period. If new transmission and gas pipeline additions are needed to accommodate the capacity expansion, this timeline is typically longer.

PJM

Overview

The PJM Interconnection analyzed potential economic impacts on electric power generation in the PJM footprint resulting from the CPP. The Organization of PJM States, which represents state utility regulators in the region served by PJM, requested analyses of several scenarios, including a comparison of regional compliance versus state-by-state compliance. PJM included additional scenarios with different assumptions in the analyses to provide modeled results covering a wide range of possible outcomes. In total, PJM analyzed 17 distinct scenarios—each was evaluated with and without the implementation of the CPP. The scenarios covered varying combinations and levels of renewable resources, energy efficiency, natural gas prices, nuclear generation, and new entry of natural gas combined-cycle resources.

PJM analyzed potential economic impacts, including the identification of fossil-fueled steam generation capacity thought to be at risk for retirement based only upon energy market simulation results. In the near future, PJM will use the results of the economic analysis to conduct a reliability analysis to determine transmission needs resulting from potential generator retirements.

Modeling and Input Assumptions

PJM ran five assumption scenarios under a regional mass-based approach for the years 2020, 2025, and 2029 to get a glimpse of compliance over the 10-year interim period. The years 2020, 2025, and 2029 were chosen so that PJM could examine the effects of the CPP at the start of the interim compliance period and a year halfway through the interim period, and then observe the effects of reaching the final targets. Although the rule permits averaging emissions rates over the 2020–2029 period, PROMOD is not a suitable tool for modeling such dynamic compliance options. As a result, each model year assumes compliance with the stated emissions target. PJM also ran one of the five OPSI-requested scenarios under a state-by-state mass-based approach to provide a comparison under the same scenario assumptions between a regional and a state-by-state approach for the year 2020.

In addition, PJM ran eight other assumption scenarios under a regional mass-based approach to provide a wider range of possible future scenarios and outcomes that could occur for CPP compliance for the years 2020, 2025, and 2029. PJM then ran two of the eight scenarios under a state-by-state compliance approach to provide additional comparisons of state-by-state and regional approaches for the year 2020. PJM also used one of the eight scenarios to run an emission-rate-based regional approach to compare outcomes and glean insights into the differences between a mass-based approach and an emission-rate-based approach for the years 2025 and 2029.

Resource Adequacy Findings

PJM's analysis shows that nearly 11,000 MW of capacity are considered at risk for retirement in at least half the scenarios, about 14,500 MW in the worst-case scenario, and only about 6,200 MW at risk in all scenarios. PJM concluded that fossil steam unit retirements (e.g., coal, oil and gas) probably will occur gradually. As the CO_2 emission limits decline over time, the financial positions of high-emitting resources should become increasingly less favorable, with lower-emitting resources displacing them more often in the competitive energy market.

Timing concerns are presented in PJM's analysis, particularly as they relate to the 2020 target compliance period. It would be prudent to examine the year 2020 since decisions by Generator Owners would likely be made at the time the base residual auctions would be held in 2016 or 2017 for the 2019–2020 or 2020–2021 delivery years, respectively—and at a time when state compliance plans would not likely be known by Generator Owners. This represents an obvious conflict between established industry planning processes and the requirements of the CPP.

Conclusions and Key Findings

- Fossil steam unit retirements (coal, oil, and gas) probably will occur gradually. As the CO_2 emission limits decline over time, the financial positions of high-emitting resources should become increasingly less favorable, with lower-emitting resources displacing them more often in the competitive energy market.
- The price of natural gas likely will be a primary driver of the cost of reducing CO_2 emissions if natural gas combined-cycle units become a significant source of replacement generation for coal and other fossil steam units.
- Adding more energy efficiency and renewable energy and retaining more nuclear generation would likely lead to lower CO_2 prices; this could result in fewer megawatts of fossil steam resources at risk of retirement, because lower CO_2 prices may reduce the financial stress on fossil steam resources under this scenario.
- State-by-state compliance options—compared to regional compliance options—likely would result in higher compliance costs for most PJM states, because there are fewer low-cost options available within state boundaries than across the entire region. However, results will vary by state given differing state targets and generation mixes. PJM modeled regional versus individual state compliance only under a mass-based approach. State-by-state compliance options would also increase the amount of capacity at risk for retirement because some states would likely face higher CO_2 prices in an individual compliance approach.

SPP

Overview

On October 8, 2014, SPP published an internal study that it conducted on the impacts the CPP would have on its system. The EPA IPM assumptions for SPP include retirements of approximately 9,000 MW of capacity associated with existing coal- and gas-fired units currently relied upon to serve load obligations in SPP. The EPA's projected electric generating unit (EGU) retirements represent approximately 6,000 MW of additional capacity being retired in SPP beyond that currently expected by 2020. The EPA projections represent approximately a 200 percent increase in retired generating capacity compared to SPP's current expectations.

SPP's assessment evaluated the impacts of the EPA's projected EGU retirements within SPP. Reliability impacts were evaluated by identifying BPS equipment overloads and low voltages both during system intact conditions and during loss of a single element and by determining impacts to SPP's reserve margin. SPP evaluated the impacts of the EGU retirements projected by the EPA that would result from implementing the carbon emission reduction goals proposed in the CPP, but due to time constraints did not evaluate the viability or reliability impacts of any of the building blocks used to establish those proposed goals.

Modeling and Input Assumptions

SPP assumed the retired capacity would be replaced by existing unused capacity remaining within the SPP footprint and surrounding areas. Then, SPP assumed the retired capacity would be replaced by a combination of existing unused capacity and new gas-fired and wind resources in the SPP footprint as needed to address capacity deficiencies. Both parts include performance of steady-state power flow analyses using models developed as described below to evaluate transmission system performance when all transmission elements are in service ("system intact") and during conditions after which any single transmission element, including a generator, is taken out of service ("first contingency" or "N-1").

Resource Adequacy Findings

SPP found in its analysis that it has a reserve margin requirement of 13.6 percent that every SPP member with load-serving responsibilities must plan to meet with appropriate generation capacity. The assessment showed that by 2020, SPP's reserve margin would fall to 4.7 percent and that in 2024, the reserve margin would fall to -4 percent. The anticipated reserve margins represent a generation capacity deficiency of approximately 4.6 GW in 2020 and 10.1 GW in 2024.

Transmission Adequacy Findings

In the analysis, SPP concluded that the SPP network would be severely stressed by large reactive deficiencies indicative of voltage collapse and blackout conditions. The analysis indicated approximately 5,200 MVar of reactive deficiencies in the SPP footprint during system intact conditions resulting from the modeled EPA generator retirements. The N-1 assessment revealed 38 overloaded elements.

Conclusions and Key Findings

- As a result of this assessment, SPP concludes that new generation and transmission expansion will be necessary to maintain reliability during summer peak conditions.
- SPP expresses concern about the timing needed for upgrades that would be required to maintain system reliability and cites a need for broader system assessments around natural gas pipeline and storage systems.
- SPP warns that outages to accommodate cut-ins of new equipment, as well as shifts in the operating characteristics of existing baseload units to more seasonal dispatch, would have a profound impact on system reliability.

WECC

Overview
WECC issued by its analysis on September 19, 2014. Through the initial efforts summarized in this document, WECC has performed preliminary analyses to provide a starting point for additional discussions and more detailed assessments. This analysis leverages WECC's new cross-functional analytical approach, where the focus is on a single reliability issue—in this case the proposed CPP—and studying it from different perspectives. Unlike the analyses performed by the ISO/RTO, WECC was able to conduct an analysis around the impacts from a pure reliability perspective.

WECC approached its analysis by performing the following:

1. **Resource Adequacy Assessment:** The resource adequacy perspective is essential to ensuring that there will be enough resources to serve peak load under various compliance scenarios. Resource adequacy assessments look at forecast load and expected resources and apply reserve margin calculations to determine if resources meet demand.
2. **Production Simulation Modeling:** Also known as production cost simulation, this perspective gives insight into operational, economic, and emission impacts the system might face under particular circumstances in the future.
3. **System Stability Studies:** This perspective provides a check on whether potential compliance scenarios create stability issues. These studies take a snapshot of the grid and investigate how the unexpected loss of equipment could impact grid reliability.

Resource Adequacy Findings
WECC's contribution to NERC's *2014 LTRA* shows that planning reserve margins are currently in excess of their targets and, based on the current assumptions posed by the EPA building blocks, impacts to resource adequacy may be minimal for the western states. WECC plans to further investigate resource adequacy in the coming months as compliance scenarios are identified by states. Like other reliability assessments, resource adequacy cannot be properly assessed absent realistic or proposed compliance scenarios.

An added value to WECC's assessment was an analysis of resource performance during frequency disruptions. In the frequency response study, 7,000 MW of coal resources were replaced by less-responsive inverter-based resources. In this analysis, the system responded to a large contingency nearly the same as it did before the coal units were replaced. This study represents a strong first-step reliability assessment, but additional scenarios must be studied across varying operational and load conditions in order to draw meaningful conclusions about system reliability. More importantly, frequency response is only one aspect of reliability, and the removal of coal resources could impact other areas, such as remedial action schemes, path ratings, and voltage stability, among others. Central to all of these studies are the assumptions on replacement generation posed by potential compliance scenarios.

Conclusions and Key Findings

- WECC's initial frequency response analysis showed that for the specific condition studied (peak summer condition only), the system was able to recover from a large contingency, and frequency response was not significantly compromised. It is important to note that these initial studies focused only on frequency response, which is one aspect of the broader system reliability picture. Reliability concerns outside this narrow area of study include remedial action schemes, path ratings, and voltage stability.
- Western states are already taking actions to reduce emissions, prior to the CPP implementation. WECC's preliminary analysis showed that states planning to retire carbon-intensive generation, implement energy

efficiency, and build out robust levels of renewable resources could make strides toward achieving the EPA goals in the next 10 years.

- Although it is still early to consider the impact of state compliance plans, preliminary WECC results have shown that decisions made regarding the CPP compliance in a state can impact grid operations, system resiliency, and potentially compliance opportunities for a neighboring state. While changes in the resource mix and forecast load in one or two states may not drastically impact the system, significant changes in four, five, or *all* western states *at once* is exponentially more concerning for a system that is inherently interconnected.

Chapter 7 – Reliability Assurance Mechanism

Maintaining Reliability Assurance

NERC's *Initial Reliability Review*[31] recommended that the EPA, FERC, the DOE, and state utility regulators employ a wide array of tools and regulatory authority to formulate a reliability assurance mechanism. Such a reliability back-stop could include timing adjustments and the granting of extensions to an entity's implementation of and compliance with its CPP implementation plan where there is a demonstrated reliability need. The key findings and conclusions presented in this Phase I assessment confirm that a reliability assurance mechanism is needed to ensure the reliability of the BPS during both the plan's development and implementation periods.[32] A defined reliability assurance mechanism, integrated within the EPA's final CPP rule, would recognize the respective roles of regulated entities, states or regions, FERC, the DOE, the EPA, and NERC while preserving BPS reliability and managing emerging and impending reliability risks.

These materials provide an overview of the rationale for why a reliability assurance mechanism is needed and additional detail regarding the ways in which a reliability assurance mechanism could work in concert with other efforts. While NERC's potential role would not be to propose certifying or approving the validity of implementation plans, reliability assessments and technical guidance on whether a specific plan could create or have the potential to create a reliability issue could be of assistance.

A NERC assessment of the overall potential impacts of the proposed CPP plans on state, multi-state, and regional grid reliability as plans are being developed and submitted to the EPA is also important for understanding the infrastructure and solutions that would need to be deployed to meet CPP requirements. Reliability assessments would (1) serve as a reliability resource to evaluate either state implementation plans during their development or aggregate entity plans once formulated, (2) enable interested stakeholders to identify grid reliability challenges and develop mitigation strategies, and (3) enhance the effectiveness and efficiency of plans by ensuring that they account for transmission and generation availability and performance, and other relevant operational and planning information from system operators and planners.

Identifying a Need for a Reliability Assurance Mechanism

The FERC-approved NERC Reliability Standards provide for the reliable operation of the BPS and help ensure that instability, uncontrolled separation, or cascading failures of the system will not occur as a result of a sudden disturbance or the unanticipated failure of system elements. Because the NERC Reliability Standards must be complied with *at all times*, the availability of a defined reliability assurance mechanism in the CPP would provide protection or relief to states, regions, and industry entities as reliability challenges occur in CPP development or during the plan's implementation.

A wide range of factors, both anticipated as well as those that could emerge during the CPP's implementation period, could impact a state's or region's conformance with the proposed CPP implementation plans. Some of these factors include the following:

- variability and uncertainty of infrastructure lead times (both generation and transmission);

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[31] http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf.

[32] Other entities have also argued that a reliability assurance mechanism is needed to ensure that reliability is maintained during the CPP's implementation. For example, the ISO/RTO Council, in its February 19, 2015 statement, provides four mechanisms, in which states will provide a foundation to assure reliability during both the planning process and implementation. These four mechanisms are:

1. Regional and multi-regional reliability assessments of the CPP plans to evaluate reliability and timing needs;
2. Established criteria for the EPA to evaluate CPP plan reliability impacts;
3. "Glide path" flexibility where it is needed due to the timing of necessary electric infrastructure development; and
4. Adoption of a safety valve process to address grid reliability impacts during the plan's implementation.

- the complexity of multi-regional coordination, which will require time to develop and can only be accomplished once definitive plans are in place;
- the technical and logistical feasibility of infrastructure development;
- NERC's mandatory transmission planning and adequacy standards, which establish BPS reliability performance requirements that must be maintained;
- unanticipated issues that could significantly alter and delay construction plans; and
- the CPP implementation period through 2030, which could introduce economic, policy, regulatory, legislative, technological, or other drivers that affect reliability plans.

NERC, as a recognized reliability authority, is capable of evaluating the reliability implications of these anticipated factors, system conditions, and infrastructure changes. In both CPP plan development among the states and implementation by industry entities, technical assessments that help determine projected reliability constraints and alignment with other reliability criteria (i.e., as required by state, ISO/RTO, or interconnection rules) would be of benefit. Additionally, system simulation and analyses to demonstrate potential reliability issues (e.g., resource adequacy, power flow and dynamics modeling, voltage stability assessment, and frequency response analysis) could also be performed.

Elements of a Reliability Assurance Mechanism

The principal elements of an effective reliability assurance mechanism should include alignment of reliability, implementation plans, regulation, and overall certainty. For the CPP, these elements will involve the regulated entities, states or regions, FERC, the DOE, the EPA, and NERC. An effective reliability assurance mechanism should also include the following elements:

- state or regional CPP plans with state and federal regulatory alignment;
- a reliability assessment by NERC of CPP plans;
- an evaluation against distinct reliability criteria and inter-area coordination;
- consideration of other reliability assurance mechanism options, including:
  - infrastructure implementation options and target impacts;
  - adjustments to implementation targets;
  - reliability-must-run generation;
  - entity- or state-specific implementation plan modifications; and
  - reliability-specific adaptations and provisions to maintain reliability.

During the CPP development stage, states or regions will be responsible for developing plans that support the CPP's targets. In developing those plans, reliability assessments and evaluations by NERC, as requested by states, would help support efforts to ensure that reliability can be maintained during the CPP implementation period as planned infrastructure is built. Based on these reliability evaluations, states could then determine whether a plan could be implemented to meet the CPP requirements. If more time is needed to support a demonstrated reliability need, a reliability assurance mechanism could be used to provide relief and align the plan with CPP targets.

During the plan implementation stage, an approved state or regional plan well underway may experience unexpected and unplanned challenges in deploying infrastructure and resources during the plan's implementation. As described in this report, external factors contribute to planning challenges and uncertainty and could impact reliability, including the siting and permitting of electric facilities (generation and transmission), the effects of neighboring areas implementing their plans, the price of fuel, and changes in customer behavior and electricity demand. As a result, some states or regions may not meet their plan targets while maintaining reliability. In these circumstances, a reliability assurance mechanism could be used to ensure that there are no adverse reliability impacts in implementing the CPP.

A reliability assurance mechanism should recognize the need for flexibility in meeting overall CPP target objectives by providing flexibility to address unique state and local reliability impacts during implementation. A reliability assurance mechanism would also provide overall regulatory certainty for states and entities and reliability assurance for the BPS.

NERC's role in an effective reliability assurance mechanism, described in more detail below, would be to provide the context for conducting reliability evaluations and assessments during the CPP's development and implementation periods. As the CPP rule and corresponding implementation plans developed by entities, states, and regions are finalized, reliability assurance requirements and guidance could be identified. In cases where plans have identified an adverse state, regional, or inter-regional reliability impact that has not been adequately mitigated or addressed, the final rule should provide regulatory certainty that a reliability assurance provision is available to adequately address infrastructure and resource needs without penalizing the states or industry entities.

NERC's Role in a Reliability Assurance Mechanism

There are three primary periods during which NERC could provide a reliability assessment and guidance for states and entities as plans are developed to implement and comply with the CPP. These reliability-focused steps could serve to support reliability assurance during refinement of state or regional plans as well as during implementation of plan elements. They are:

1. **During the CPP Plan Development Period:** As states are developing their state implementation plans or regional implementation plans, NERC could serve as a resource in assessing reliability or identifying potential reliability concerns. While NERC's role would be advisory and non-binding, NERC could develop written guidance and criteria by which plans may be developed, reviewed, and evaluated.
2. **During the Plan Review and Approval Period:** After the CPP final rule has been issued and prior to the initial submittal dates for state and regional implementation plans, NERC plans to undertake its Phase II assessment of the CPP, currently anticipated by mid-2016. Additionally, NERC would continue to conduct its long- and short-term reliability assessments, which would reflect aggregate entities' implementation plans within state or regional CPP plans. Reliability assessments and review of the plans before they are finalized could identify areas where there may be a reliability issue.
3. **During the Plan Implementation Period:** As actual, emerging, or anticipated reliability issues are identified, factors that might impact an entity's ability to ensure reliability while satisfying the CPP may occur. Those factors include:
    a. insufficient time to implement infrastructure additions or modifications needed to maintain reliability;
    b. unanticipated conditions or circumstances directly affecting implementation plans, leading to reliability issues;
    c. an entity identifying an impending conflict between assuring reliability and satisfying the CPP implementation plan; or
    d. an entity determining that meeting the requirements of the CPP implementation plan will require load to be shed.

The proposed framework outlined in Figure 24 offers more detail on how reliability-focused steps throughout all stages of the CPP's implementation—including during CPP plan development, CPP plan review and approval, and CPP plan implementation—could be pursued.

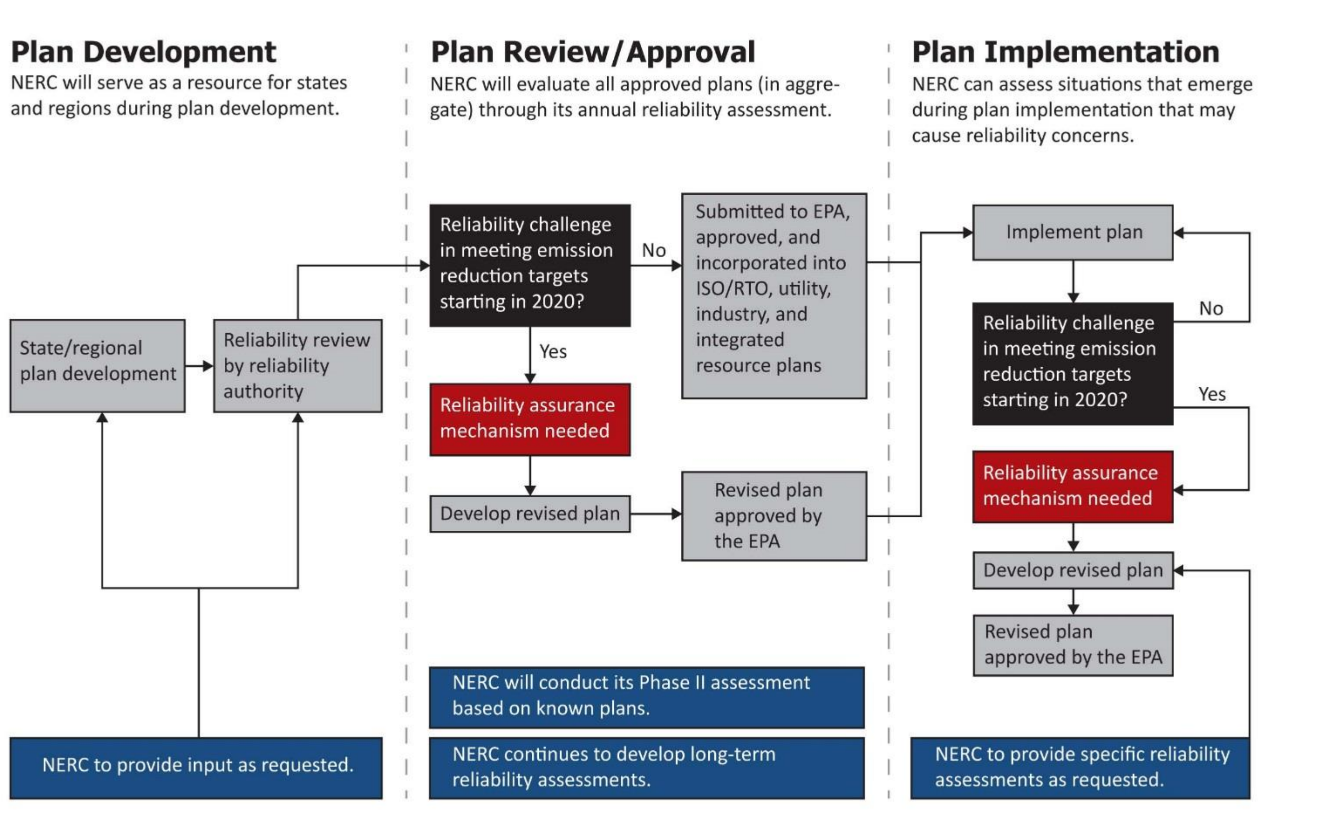

Figure 24: A Framework for NERC's Advisory Role and the Reliability Assurance Mechanism

In the framework proposed above, NERC is available to work with states, FERC, the DOE, the EPA, and others throughout the process to ensure this reliability information is available to them as progression toward environmental plans and CPP requirements is being made.

Conclusions

NERC recommends adoption of a reliability assurance mechanism in the CPP final rule that could be based on the specific roles described above. Further, NERC recommends that policy makers help ensure that state or regional implementation plans that are developed to meet the CPP requirements provide assurances that reliability can be sustained during the CPP's implementation period. Plans that require greater infrastructure development of either gas pipelines, transmission, supply resources, or other assets will require time to ensure these infrastructure accommodations can be made with reliability certainty. A reliability assurance mechanism, along with sufficient timelines to accommodate infrastructure development, can facilitate a reliable transition and ensure BPS reliability.

Chapter 8 – Recommendations, Conclusions, and Future Steps

This report represents NERC's continuing efforts to identify concerns regarding the EPA's proposed CPP. As the CPP is finalized and implemented, NERC will continue to develop special reliability assessments in phases. 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. 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.

Recommendations

1. **NERC should continue to update and expand the assessments of the reliability implications of the proposed CPP and provide independent evaluations to stakeholders, states, regulators, and policy makers. NERC should continue to conduct a phased assessment strategy that provides insight and guidance as the CPP rule is finalized and implementation plans begin to be formalized.**
   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 meeting. Additionally, as part of its normal course of duty and responsibility, NERC annually conducts seasonal and long-term reliability assessments. Each year, NERC evaluates aggregated and regional system plans that cover the entire BPS in North America. Over the next several years, these assessments will incorporate the CPP rule's implementation.

2. **Coordinated regional and multi-regional industry planning and analysis groups should continue to conduct detailed system evaluations to identify areas of reliability concern and work in partnership with states, regions, and policy makers to provide clear guidance of the complex interdependencies resulting from the CPP rule's implementation.**
   Given the approaching 2020 interim target date identified in the proposed CPP, 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 state or regional plans 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. 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). Finally, ISO/RTOs, utilities, and Regional Entities should analyze the impacts to ERSs through the ongoing efforts of NERC's ERS Task Force.

3. **Policy makers, states, regions, and regulators (including the EPA) should develop implementation plans that allow for more time to address potential BPS reliability risks and infrastructure deployment requirements during the transition period.**
   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 Phase I assessment, more time would be needed in certain areas to ensure that resource adequacy, reliability requirements, and infrastructure needs are maintained. The EPA, FERC, the DOE, and state utility regulators should consider it their regulatory authority to make timing adjustments and to grant extensions to preserve BPS reliability, considering lead times for infrastructure as a critical path. Regulators should also consider developing approaches to expedite project approval processes as a mitigation strategy for reliability issues that may emerge.

4. **The EPA should include a formal reliability assurance mechanism in the final rule that provides the regulatory certainty and explicit recognition of the need to ensure reliability during both the plan development and the implementation period through 2030—and potentially beyond. NERC has outlined a specific series of roles for providing reliability guidance and independent assessments, in the form of a reliability assurance mechanism.**
   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 mechanism is included in the rule's implementation. Further, NERC recommends that policy makers ensure that state or regional implementation plans provide demonstrated assurances that reliability can be sustained during the CPP's implementation period. Plans that require greater infrastructure development of either gas pipelines, transmission, supply resources, or other assets will require time to ensure these infrastructure accommodations can be made with certainty. A reliability assurance mechanism, along with sufficient timelines to accommodate infrastructure development, can facilitate a reliable transition and ensure BPS reliability.

5. **State and regional plans should be developed with consultation from reliability authorities (Planning Coordinators and Transmission Planners).**
   System-specific analysis will be needed to evaluate the effects of the proposed CPP and demonstrate reliability. These efforts will require more in-depth and system-specific analysis, which includes evaluating transmission adequacy under contingency scenarios, examining voltage and transient stability caused by system disturbances, and determining interchange power transfer capabilities between systems. Reliability authorities have the tools and subject matter expertise to conduct these analyses and determine explicit reliability.

Next Steps for NERC Reliability Assessments

Over the next several months, NERC intends to coordinate with federal and state regulatory authorities to provide guidance and insights about the results and conclusions of NERC's Phase I assessment. The CPP is expected to be finalized during the summer of 2015. Once the CPP is finalized, NERC will conduct an additional review and assessment (Phase II) to support state and regional plan development.

Appendix A – AURORAxmp Model vs. IPM Model

Background

The AURORAxmp electric power market forecasting tool is a fundamentals-based power market model that economically dispatches generation capacity to simulate the operations of each power market in the continental United States. The model optimizes dispatch by using the lowest-cost resources to meet electricity demand in a given region at the hourly level and builds the most economic new resources to meet reserve margin targets and future load growth.

The Integrated Planning Model (IPM) analyzes the projected impact of environmental policies on the electric power sector in the 48 contiguous states and the District of Columbia. Developed by ICF Consulting, Inc. and used to support public- and private-sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least-cost capacity expansion, electricity dispatch, and emission control strategies for meeting energy demand and environmental, transmission, dispatch, and reliability constraints.

IPM and AURORAxmp typically are used to support resource planning, regulatory analysis, commodity price forecasting, and asset valuation, and both seek to determine the least-cost method to meet electricity demand given various exogenous inputs and constraints.

Even though IPM and AURORAxmp have similar goals, there are several significant differences between the models.

1. IPM aggregates similar types of capacity (fuel and technology type) and applies weighted-average operating parameters to the grouped capacity, as opposed to populating the model with each generating unit and applying its real-life operating parameters. Therefore, IPM aggregates the 16,330 existing generating units in the electric power sector into 4,971 “model units” to simplify the analysis and reduce run time.
2. The AURORAxmp database was populated by information from individual power plant generators and does not aggregate multiple or different plants together. Therefore, the AURORAxmp model simulates how each power plant operates in real life on an hourly basis.
3. Regarding dispatch logic, IPM breaks up each model year into two seasons: winter and summer. The hourly demand in each season is then ordered from highest to lowest to develop a load-duration curve. IPM’s aggregated units are then dispatched to create generation and power prices. IPM’s method solves for the entire season at once, rather than dispatching units in each hour.

Rationale for Model Selection

The AURORAxmp dispatch logic economically dispatches each generation unit against electricity demand for each chronological hour. AURORAxmp closely mimics the actual power markets’ day-ahead and real-time dispatch practices and captures many of the unintended re-dispatch inefficiencies introduced by the CPP that a load-duration-curve-based approach would not. The input assumptions for each model have differing effects. For example, the IPM model retires coal units that the AURORAxmp model assumes will continue to run but at much lower load factors (considered at-risk for sustained operation). Therefore, the results achieved were different for projected unit retirements and the timing of these retirements. However, both models indicated close to the same results in both capacity and energy shifts of all resource types between 2020 and 2030.

Appendix B – Steady-State Power System Analysis Methods

Study Methods

To implement unit retirements in the power flow models, a small group of units (i.e., a few units at a time) were retired and new units were added to compensate for the generation deficiency. The reason for this approach was ease of obtaining a power flow solution (experience proved that retiring all the units at once caused power flow to diverge).

Following the selection of locations for new units, a transmission voltage level was selected that most appropriately accommodates the amount of added generation. Next, a power flow simulation was performed for generation displacement and transmission facility addition. The aforementioned process was repeated until all required unit retirements and additions were implemented.

Steady-State Analysis; Contingency Considerations

Bulk power systems must provide adequate generation and transmission capacity to meet the demand while satisfying system operating constraints, but also be capable of maintaining system stability following faults, facility switching, and other disturbances. Reliability of a bulk system can be evaluated by two attributes: adequacy and security. Adequacy refers to the ability of the system to supply the aggregate electric energy requirements of loads within equipment ratings and voltage limits when planned and unplanned component outages occur. Adequacy assessment involves system steady-state conditions of post-contingencies; i.e., the system is assumed to always reach a stable equilibrium point after equipment outages, and the dynamics of the transition from one state to another are neglected. The second attribute, system security, refers to the ability of the power system to withstand disturbances arising from faults or equipment outages. Security assessment involves modeling system-transient responses and potential cascading sequences after a disturbance. Transient responses include the fluctuations of both the frequency and voltage.

Contingency

A contingency is an unexpected event that could result in the loss of one or more BPS facilities. The following contingency categories are defined by NERC:

- All facilities in service (Category A); i.e., system intact N-0
- Event resulting in loss of a single element (Category B), N-1
- Event(s) resulting in the loss of two or more (multiple) elements (Category C), N-2 or multiple
- Extreme events resulting in the loss of two or more elements (Category D), N-2 or multiple

Power System Model

Power system models of the North American power system are created on an annual basis by ERAG, WECC, and TRE and are required for power system planning studies. Power flow and dynamic models for the current year and future years are assembled by NERC Regional Entity members. ERAG-MMWG regional members, on a yearly basis, assemble power system models (power flow and dynamic model) for future years (e.g., the 2015 power flow base case series span from 2015 to 2025 for a total of 15 cases). Subsequently, NERC Regional Entities and MMWG coordinators produce complete ERAG models. WECC and TRE follow a similar approach.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
(404) 446-2560 | www.nerc.com