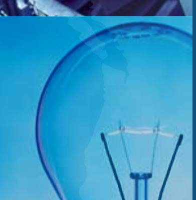
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2010 Special Reliability Scenario Assessment:

Resource Adequacy Impacts of Potential U.S. Environmental Regulations



to ensure the reliability of the bulk power system

October 2010

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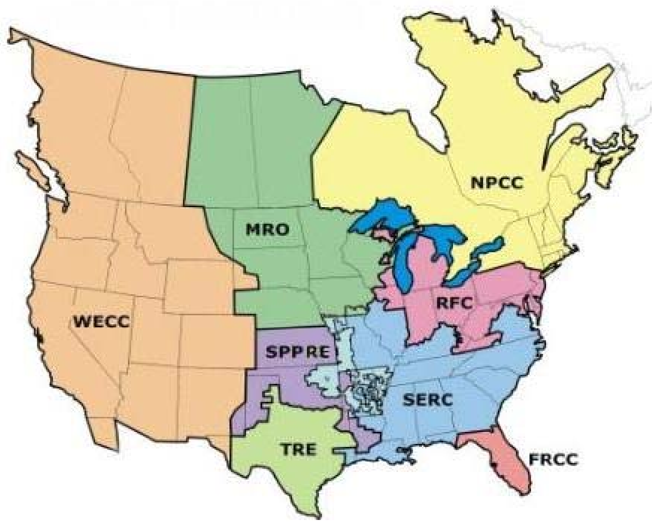
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority established to evaluate reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the bulk power system; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization for North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports on the reliability and adequacy of the North American bulk power system, which is divided into eight Regional areas, as shown on the map below and listed in Table A. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: *The highlighted area between SPP and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

Table A: NERC Regional Entities

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

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec, and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards-setting bodies by the *Régie de l'énergie* of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have frameworks in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

Table of Contents

Executive Summary

In the United States, several regulations are in the process of being proposed by the U.S. Environmental Protection Agency (EPA) that directly affect the electric industry. Depending on the outcome of any or all of these potential regulations, the results could accelerate the retirement of a significant number of fossil fuel-fired power plants. EPA is currently developing rules that would mandate existing power suppliers to either invest in retrofitted environmental controls at existing generating plants or retire them. The most significant proposed EPA rules have been in development for over ten years and are currently undergoing court-ordered revisions that must be implemented within mandatory timeframes.

The results of this assessment show a significant potential impact to reliability should the four EPA rules be implemented as proposed. The reliability impact will be dependent on whether sufficient replacement capacity can be added in a timely manner to replace the generation capacity that is retired or lost because of the implementation of these rules. Implementation of the rules must allow sufficient time to construct new capacity or retrofit existing capacity. Planning Reserve Margins appear to be significantly impacted, deteriorating resource adequacy in a majority of the NERC Regions/subregions. In this scenario, reduced Planning Reserve Margins are a result of a loss of up to 19 percent of fossil fuel-fired steam capacity in the United States by 2018.[2] Additionally, considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort.

This assessment examines four potential EPA rulemaking proceedings that could result in unit retirements or forced retrofits between 2013 and 2018. Specifically, the rules under development include:

1. Clean Water Act – Section 316(b), Cooling Water Intake Structures
2. Title I of the Clean Air Act – National Emission Standards for Hazardous Air Pollutants (NESHAP) for the electric power industry (referred to herein as Maximum Achievable Control Technology (MACT) Standard)
3. Clean Air Transport Rule (CATR)
4. Coal Combustion Residuals (CCR) Disposal Regulations

This assessment is designed to evaluate the potential impacts on Planning Reserve Margins, assuming that there would be no industry actions in the near term to address compliance issues or market response, and identify the need for additional resources that may arise in light of industry responses to each of these environmental regulations individually and in aggregate. Additionally, this assessment considers the number of generating units requiring retrofitting by NERC Region and subregion to demonstrate the magnitude of construction planning necessary for compliance in a timely fashion. The assessment relies on two separate scenario cases for each proposed rule, calculating the amount of capacity reductions due to accelerating unit retirements and increased station loads needed to power the additional environmental controls. For each

[2] A 19 percent reduction represents the results of the total capacity loss in the Strict Case for 2018 as a percentage of the total coal, gas, and oil steam units included in the 2009 Long-Term Reliability Assessment Reference Case. Refer to Appendix III and IV for details values.

proposed EPA rule and in aggregate, units were retired for this assessment based on an agreed upon cost calculation.[3]

Two scenario cases (Moderate Case and Strict Case) provide a range of sensitivities, with the Strict Case incorporating more stringent rule assumptions and higher compliance costs. The potential impacts of greenhouse gas (GHG) legislation are not considered in this assessment, but have been discussed separately in a recent NERC report.[4] Overall, the impact on reliability is a function of the timeline for finalizing the rules and ensuring compliance with the potential EPA regulations. The reliability impact of these rules will be dependent on whether sufficient replacement capacity can be added in a timely manner to replace the generation capacity that is retired or lost because of the implementation of these rules. This assessment does not account for industry's ability to acquire, construct, or finance replacement resources; however, implementation of the rules must allow sufficient time to construct new capacity or retrofit existing capacity.

Figure A: Summary and Highlights of the Four EPA Regulations Assessed[5]

Combined EPA Regulations

-Potential impacts approximately 33-70 GW (retrofit plus retired) capacity by 2015.

- Aggregate effects of multiple regulations increases unit retirement.

- Estimates predict the majority of retirements occur by 2015.

-More units predicted to be retired rather than retrofit

316(b)

- Likely to have the greatest capacity impacts of all four regulations.
- Resulting impacts cause the early retirement of mostly oil/gas-fired steam generation units.
- Smaller units are most likely to be retired as a result of the high retrofitting costs.
- All nuclear generation is assumed to retrofit, resulting in up to a 3.5 percent capacity derate.

MACT

- Moderate Case and Strict Case impact estimates show a high degree of capacity variation in different time periods, due to the implementation rules assumed to be enforced by the EPA.
- Resulting impacts highly dependent on waiver extensions past the 2015 "hard stop" compliance deadline.
- Individually, MACT affects coal -fired units.

CATR

- Only regulation to start affecting capacity in the Regions by 2013.
- Emission limitations and trading options will largely affect the amount of overall capacity reductions.
- Effects mainly felt by RFC and SERC-Gateway.

CCR

- Relatively minimal capacity impact in only a few Regions.
- Large-scale retrofit projects must be coordinated
- Cost plays larger role in the Combined EPA Regulations Scenario.

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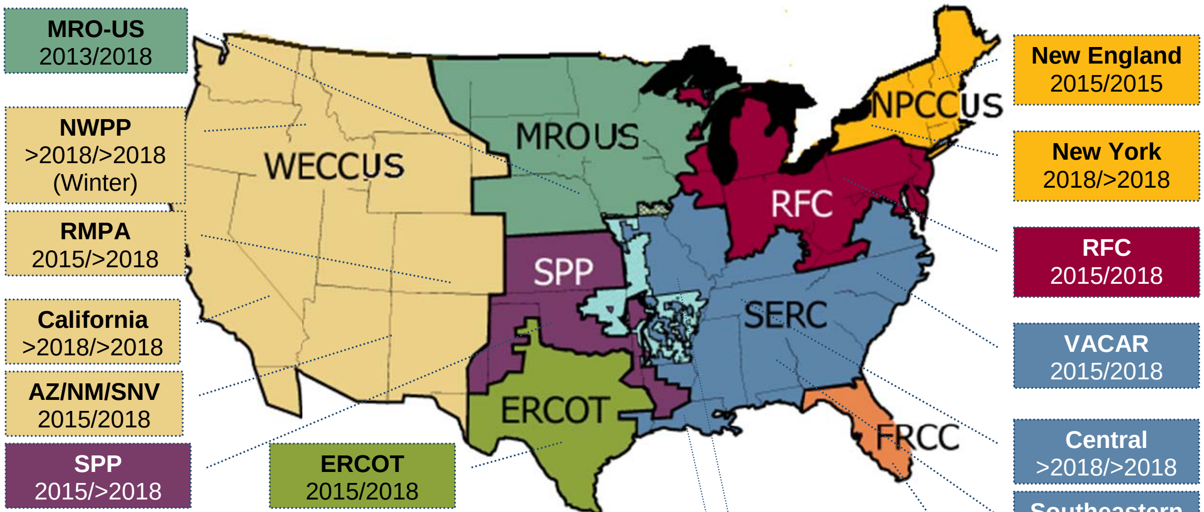
[3] Unit is retired if (CC+FC+VC) / (1-DR) > RC, where: CC = required compliance cost in $/MWH, FC = current fixed O&M in $/MWH, VC = variable O&M including fuel cost in $/MWH, RC = replacement cost in $/MWH and DR = derate factor that accounts for the incremental energy loss due to any new environmental controls. See *Appendix I, Assessment Methods*.

[4] http://www.nerc.com/files/RICCI_2010.pdf

[5] Individual EPA Regulations are listed in order of greatest potential impact to least top to bottom, left to right.

Executive Summary

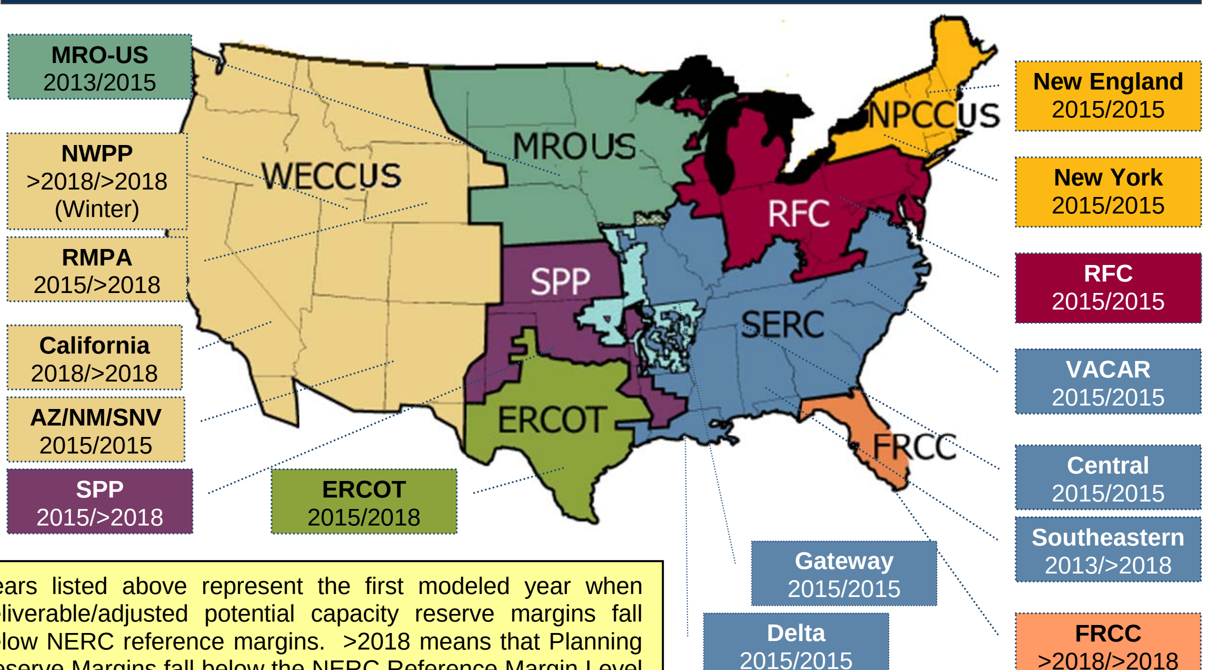
Figure B: Moderate Case Deliverable and Adjusted Potential Resources Reserve Margins Compared to NERC's Reference Margin Level



Years listed above represent the first modeled year when deliverable/adjusted potential capacity reserve margins fall below NERC reference margins. >2018 means that Planning Reserve Margins fall below the NERC Reference Margin Level at a time beyond 2018.

Deliverable Reserve Margin – Existing and Future-Planned Resources
Adjusted Potential Reserve Margin – Existing, Future-Planned, and Adjusted Potential Resources (Conceptual resources adjusted by a confidence factor)

Figure C: Strict Case Deliverable and Adjusted Potential Resources Reserve Margins Compared to NERC's Reference Margin Level



Years listed above represent the first modeled year when deliverable/adjusted potential capacity reserve margins fall below NERC reference margins. >2018 means that Planning Reserve Margins fall below the NERC Reference Margin Level at a time beyond 2018.

Proposed EPA Regulations May Have Significant Impacts on Forecast Planning Reserve Margins

Without additional power production or demand-side resources beyond those in current regional plans, the combined effects of the four EPA rules (Combined EPA Regulation Scenario) are shown to significantly affect Planning Reserve Margins and, in most Regions/subregions, more resources would be required to maintain NERC Reference Margin Levels. Up to a 78 GW reduction of coal, oil, and gas-fired generating capacity is identified for retirement during the ten-year period of this scenario. For the Moderate Case, this occurs in 2018; however, in the Strict Case a similar reduction occurs in 2015. The reduction in capacity significantly affects projected Planning Reserve Margins for a majority of the NERC Regions and subregions. Potentially significant reductions in capacity within a five-year period may require the addition of resources. For the United States as a whole, the Planning Reserve Margin is significantly reduced by nearly 9.3 percentage points in the Strict Case, significantly deteriorating future bulk power system reliability.

Rule Implementation Timeline Should Consider Reliability Impacts

Overall, impacts on Planning Reserve Margins and the need for more resources is a function of the compliance timeline associated with the potential EPA regulations. The Combined EPA Regulation Scenario affects a large amount of units, affecting some Regions more significantly than others. Based on the assessment's assumptions, the greatest risk to Planning Reserve Margins occurs by 2015 in the Combined EPA Regulation Scenario. The majority of the impacts will be seen within the next five years, requiring additional resources in a short timeframe. This situation is compounded by the large number of electric generation units that are likely to retrofit with environmental controls, as well as the convergence of overlapping replacement/retrofit generation capacity projects and heavy U.S. infrastructure projects in other sectors. Potential constraints of skilled construction labor, material shortages, financing, and escalation of compliance costs coupled with coordination of overlapping outages resulting in congestion expenses could present challenges in meeting the compressed time schedule.

Individually, the Section 316(b) Cooling Water Intake Structures Rule Has the Greatest Potential Impact on Planning Reserve Margins

Implementation of this rule will apply to 252 GW (1,201 units) of coal, oil steam, and gas steam generating units across the United States, as well as approximately 60 GW of nuclear capacity (approximately a third of all resources in the U.S.). Of this capacity, 33-36 GW (see Figure D) may be economically vulnerable to retirement if the proposed EPA rule requires power suppliers to convert to recirculating cooling water systems in order to continue operations. The remaining capacity may also be converted assuming it is unaffected by other proposed rules, resulting in a 5 GW derating across the United States. Therefore, the total capacity vulnerable to retirement increases to 37-41 GW. Planning Reserve Margins in almost half of NERC Regions/subregions are below the NERC Reference Margin Level by 2015. For example, in this scenario, Planning Reserve Margins are decreased by 18 percentage points in the SERC-Delta subregion, where the margin falls below zero. Other Regions/subregions significantly affected subregions include NPCC-New England and New York.

Executive Summary

The MACT, CATR, and CCR Rules Also Contribute to Reductions in Capacity

Ranked in descending order of impact severity, the regulatory impacts of MACT, CATR and finally CCR on retirements, individually also accelerate retirements and will mostly affect existing coal-fired capacity:

- The **MACT Rule** considered alone could drive Planning Reserve Margins of 8 regions/subregions below the NERC Reference Margin Levels standards and trigger the retirement of 2-15 GW (Moderate to Strict Cases) of existing coal capacity by 2015. To comply, owners of the remaining capacity need to retrofit from 277 to 753 units with added environmental controls. The "hard stop" 2015 compliance deadline proposed by the MACT Rule makes retrofit timing a significant issue and potentially problematic.

- The **CATR** could have significant impacts as soon as 2015 should EPA require emission limits with no offset trading, resulting in potentially 3-7 GW of potential retirements and derated capacity, requiring retrofitting of 28-576 plants with environmental controls by 2015 (Moderate to Strict Cases). Planning Reserve Margins are affected most in the SERC-Gateway subregion with reductions starting in 2013.

- The **CCR Rule** alone is projected to have the least impact, triggering the retirement of up to 12 coal units (388 MW). Cost sensitivity assessment for CCR reveals that retirements could reach capacity of 2 GW (53 units) should costs exceed the assessment's Strict Case expenditure estimate by a factor of ten. While the resulting impacts of the CCR scenario may not have significant impacts to capacity by themselves, the associated compliance costs of CCR contribute to the Combined EPA Regulation Scenario.

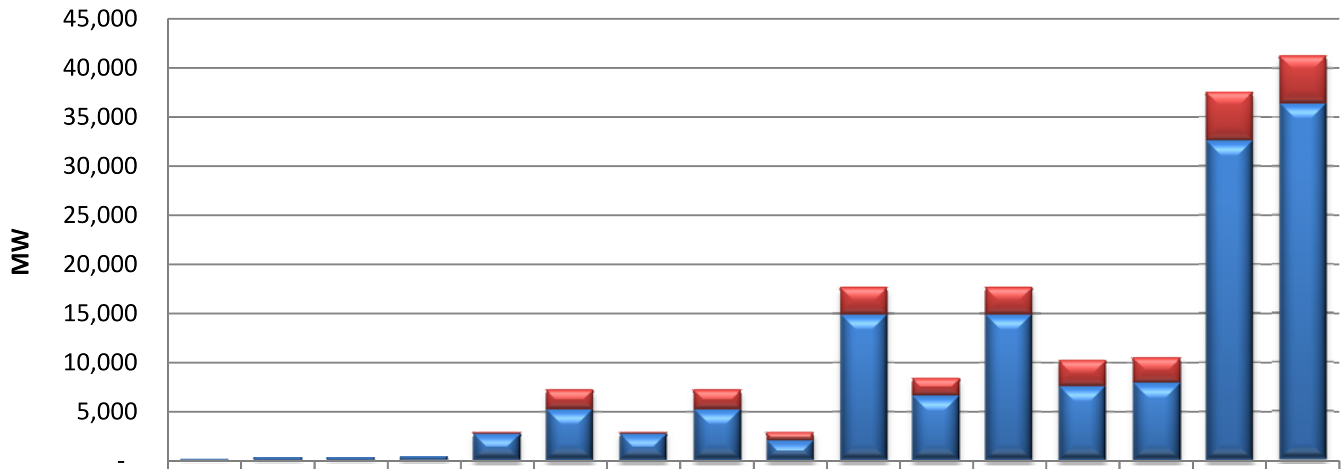
EPA Regulations Create a Need for Prompt Industry Response and Action

This report also identifies a number of tools the industry has for mitigating potential reliability impacts from the implementation of EPA regulations. For example, advancing Future or Conceptual resource in-service dates or the addition of new resources not yet proposed could help partially alleviate projected capacity losses in severely affected regions. Price signaling for the need of new resources will be important.

Industry coordination will be vital to ensure retrofits are completed in a way that does not diminish reliability. In addition, statutory and regulatory safeguards also allow the EPA, the President of the United States, and the Department of Energy to extend or waive compliance under certain circumstances. Implementing these industry and regulatory tools may be critical to maintain the reliability of the bulk power system.

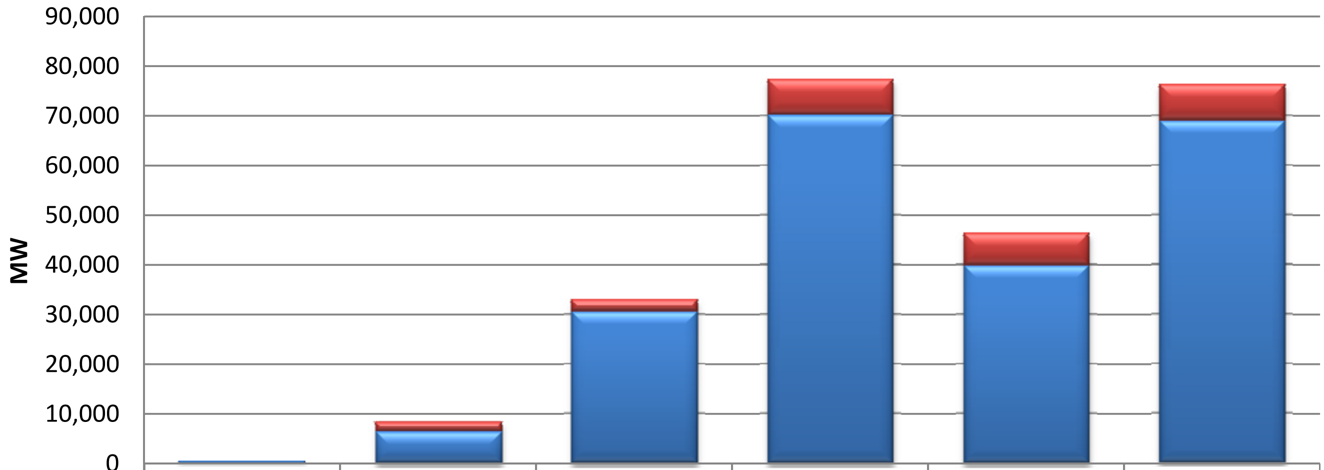
Second tier effects, including generation deliverability or stability impacts, must also be considered. For example, transmission system construction, enhancements, reconfiguration and development of new operating procedures may be necessary in some areas, all of which can create additional timing considerations.

Figure D: Potential Capacity Reduction Impacts Due to Each Potential EPA Regulation



	CCR				CATR				MACT				316(b)			
	2015		2018		2015		2018		2015		2018		2015		2018	
	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case	M Case	S Case
Derate (MW)	0	0	0	0	142	1,952	142	1,952	806	2,746	1,750	2,746	2,575	2,551	4,954	4,848
Retired (MW)	130	287	287	388	2,740	5,221	2,740	5,221	2,061	14,879	6,617	14,879	7,597	7,880	32,522	36,366

Figure E: Potential Capacity Reduction Due to the Combined EPA Regulation Scenario



	2013		2015		2018	
	Moderate Case	Strict Case	Moderate Case	Strict Case	Moderate Case	Strict Case
Derate (MW)	17	1,934	2,394	7,289	6,479	7,348
Retired (MW)	538	6,457	30,563	70,059	39,867	68,979

Recommendations

Regulators

In the future, a variety of demands on existing infrastructure will be made to support the evolution from the current fuel mix, to one that includes generation that can meet proposed EPA regulations. The pace and aggressiveness of these environmental regulations should be adjusted to reflect and consider the overall risk to the bulk power system. EPA, FERC, DOE and state utility regulators, both together and separately, should employ the array of tools at their disposal to moderate reliability impacts, including, among other things, granting required extensions to install emission controls.

Industry

Regulators, system operators, and industry participants should employ available tools to ensure Planning Reserve Margins are maintained while forthcoming EPA regulations are implemented. For example, regional wholesale competitive markets should ensure forward capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in regulated markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations.

NERC

NERC should further assess the implications of the EPA regulations as greater certainty or finalization emerges around industry obligations, technologies, timelines, and targets. Strategies should be communicated throughout the industry to maintain the reliability of the bulk power system. This assessment should include impacts to operating reliability and second tier impacts (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) of forthcoming EPA regulations.

Note: *The results in this report are based on assumptions of potential EPA regulations. The regulations discussed in this report are not yet final and all compliance deadlines, emission limitations, and retrofit costs may differ once the rules are finalized. This is a scenario of potential bulk power system impacts based on what is known today about the potential implementation of these rules. The resulting resource loss from these potential rules represent the loss of capacity should no more resources be added beyond the reference case.*

Executive Summary

Introduction

In the United States (U.S.), the electric power industry has made significant capital investment in air pollution control technologies to remove sulfur dioxide (SO_2), particulate matter and nitrogen oxide (NO_x) emissions at fossil-fired power plants. The bulk of these capital investments were made to existing coal plants in order to comply with evolving environmental regulations.

Several regulations are in the process of being proposed by the U.S. Environmental Protection Agency (EPA) requiring additional retrofits. Depending on the final determinations, the cost to comply with the final regulations may result in retirements of generation. This assessment is designed to consider four potential EPA regulations and their potential impacts on Planning Reserve Margins individually and in aggregate.[6] The four regulations assessed are:

1. Clean Water Act – Section 316(b), Cooling Water Intake Structures;
2. Title I of the Clean Air Act – National Emission Standards for Hazardous Air Pollutants (NESHAP), or Maximum Achievable Control Technology (MACT) Standards;
3. Clean Air Transport Rule (CATR); and
4. Coal Combustion Residuals (CCR)

Assumptions (described in detail later in this section) have been made in this assessment to measure the potential impacts on Planning Reserve Margins from these potential regulations before knowing how companies will actually respond to these requirements and market conditions. The goal is to provide industry and regulators additional information regarding the scope of generating units financially affected by the potential EPA Regulations and about the necessity for replacement capacity to maintain reliability during the implementation process—it is a hypothetical set of scenarios employing agreed upon assumptions.[7] Ultimately, plant owners will determine the costs of compliance and make decisions about investment versus unit retirement. For this assessment, a unit is assumed to retire if (CC+FC+VC) / (1-DR) > RC, where: CC = required compliance cost, FC = current fixed O&M, VC = variable O&M including fuel cost, RC = replacement cost all in $/MWH, and DR = derate factor that accounts for the incremental energy loss due to any new environmental controls. See *Appendix I: Assessment Methods* for more details.[8]

Below is a summary of the aforementioned regulations, listed in order of magnitude:

1. **Clean Water Act – Section 316(b), Cooling Water Intake Structures**
   A significant number of thermal (coal, nuclear, oil and gas steam) generation plants use cooling water to support the process of generating electricity and therefore, they are located on large water bodies or high flow-rate rivers. Many of these facilities use once-through cooling systems that draw large volumes of water from the ocean, lake, or river used to condense steam, returning the warmer water back into the body of water immediately after use. Section 316(b) of the Federal Water Pollution Control Act (FWPCA), more commonly known as the Clean Water Act, regulates intake structures for surface waters in the U.S. and calls for Best Technology Available (BTA) to

[6] Analysis performed by Energy Ventures Analysis, Inc. (http://www.evainc.com) for NERC in February-July 2010 serves as the basis for this report. Detailed status of the assessed regulations can be found in *Appendix II, Environmental Regulations*
[7] NERC vetted assumptions used in this assessment with the Reliability Assessment Subcommittee and multiple industry groups.
[8] The potential effects of pending CO_2 regulations were not included.

minimize adverse environmental impact (AEI). EPA has interpreted that to mean impingement mortality of fish and shellfish and entrainment of their eggs and larvae. EPA's rulemaking is expected to set significant new national technology-based performance standards to minimize AEI. EPA is revising its rules for cooling water intake structures at "existing" facilities – including electric power generating stations. EPA has moved to combine the Phase II (large existing generators) and Phase III (small existing generators, offshore oil & gas facilities and other manufacturing facilities) rules into one proceeding and plans to propose a revised rulemaking by February 2011 and a final rule is to be promulgated by July 2012.

In 2004, EPA originally adopted Phase II regulations to minimize impingement and entrainment of aquatic life in the water intake structures that applied to large existing power plants withdrawing 50 million or more gallons per day and using at least 25 percent of the water withdrawn for cooling purposes. Sources could comply using several alternatives.

However, a January 2007 ruling by the Second U.S. Circuit Court of Appeals remanded several provisions of the Phase II rule and EPA subsequently suspended its Phase II implementation[9] and is in process of developing a new rule to address the court concerns. Steam generating units employing once-through cooling systems could be required to replace their cooling water systems with closed-loop cooling systems.

This can affect Planning Reserve margins in two ways: 1) the cost of such retrofits may result in accelerated unit retirements and 2) closed-loop cooling retrofitting results in derating a unit's net output capacity, due to additional ancillary or station load requirements to serve generator equipment. This resource assessment and its implications for responses in the power generation market should inform and affect power plant owner's choices about plant retirements, plant additions, and unit retrofits.

2. **Title I of Clean Air Act – National Emission Standards for Hazardous Air Pollutants for the electric power industry, or Maximum Achievable Control Technology (MACT) Standards**

   NESHAP or MACT requires coal-fired plants to reduce their emissions of air toxics, including mercury. In December 2000, the U.S. EPA issued a "regulatory determination" under the 1990 Clean Air Act Amendments that regulation of mercury is "appropriate and necessary" for coal- and oil-fired power plants. Title I of the Amendments required EPA to adopt MACT standard for air toxic control. In March 2005, EPA issued its final Clean Air Mercury Rule (CAMR) for coal-based power plants. The CAMR used a market-based cap-and-trade approach to require emissions reductions in two phases: 1) a cap of 38 tons in 2010 and 2) fifteen tons after 2018, for a total reduction of 70 percent from current levels. Facilities were to demonstrate compliance with the standard by holding one "allowance" for each ounce of mercury emitted in any given year. In the final rule, EPA stated the regulation of nickel emissions from oil-fired plants is not "appropriate and necessary." In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion in a case, which was initiated by 15 states and other groups, challenging the CAMR and EPA's decision to "de-list" mercury as a hazardous air pollutant (HAP). The Court held that EPA's reversal of the December 2000

[9] http://www.epa.gov/waterscience/316b/phase2/implementation-200703.pdf

regulatory finding was unlawful.[10] The Court vacated both the reversal and the CAMR. In February 2009, the acting Solicitor General, on behalf of EPA, filed a motion with the Supreme Court to dismiss the CAMR case. The motion states unequivocally that EPA will develop MACT standards for the utility industry under section 112 of the Clean Air Act. EPA is now obligated under a consent decree to propose a MACT rule by March 16, 2011 and to finalize the rule by November 16, 2011. In the interim, 19 states have already adopted their own mercury control requirements.

Section 112 in Title I of the Clean Air Act requires EPA to develop MACT standards for all the other listed air toxics emitted by coal- and oil-fired power plants. Based on an Information Collection Request (ICR), EPA is likely to set MACT standards for mercury, acid gases, heavy metals, and organics for coal- and oil-fired power plants. This could require significant additional emissions control equipment beyond what is necessary for compliance with mercury-only regulations. Under the Clean Air Act, EPA is obligated to implement the stricter standards within three years after the regulation becomes final.

3. **Clean Air Transport Rule (CATR)**

On July 6, 2010, EPA proposed a CATR program to reduce long-range transport of pollutants significantly contributing to downwind state ground-level ozone and fine particle non-attainment problems. This program would replace EPA's earlier Clean Air Interstate Rule that was overturned by the U.S. Court of Appeals in 2008 and temporarily reinstated until a replacement program was developed. As drafted, CATR would sharply reduce emissions of sulfur dioxide and nitrogen oxide from power plants in 31 states and the District of Columbia. EPA proposed three program options for public comment:

1) the EPA preferred option which sets state emission budget caps and allows intrastate trading and limited interstate trading among power plants;
2) the EPA Alternative 1 option which sets state emission budget caps and allows intrastate trading among power plants within a state; and
3) the EPA Alternative 2 option which sets a pollution limit for each state and specifies the allowable unit-specific emission limit

Each of these options poses different reliability impacts. EPA will revise future state emission budgets as new stricter ozone and fine particulate ambient air quality standards are implemented. Depending on the outcome of the final regulation, power plant owners will likely need to retrofit additional emissions controls and, in some cases, retire units.[11]

4. **Regulations on Coal Combustion Residuals (CCR)**

Coal-fired power plants currently dispose of more than 130 million tons per year of coal-ash and solid byproducts. The failure of an ash disposal cell in December 2008 highlighted the concerns of coal-ash disposal and triggered calls for tighter regulation.[12] In May 2010, EPA proposed two options to regulate coal combustion residual disposal.[13]

[10] http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf

[11] A follow-on rule "Transport Rule 2" is also being developed for proposal by the EPA that would require more environmental controls not covered by CATR, regulating NOx in particular. This would apply to a majority of the states in the Eastern Interconnection plus Texas. This rule is not assessed in this report, but may contribute to more investments in required control technologies needed.

[12] Disposal cells are used for settling and storing the coal fly ash. This accident occurred at TVA's Kingston Fossil Plant East Tennessee. http://www.tva.gov/kingston/index.htm

[13] http://www.epa.gov/wastes/nonhaz/industrial/special/fossil/ccr-rule/ccr-rule-prop.pdf

1) Regulate the coal fly ash as a special waste under subtitle C (hazardous waste) of the Resource Conservation and Recovery Act (RCRA). Under this option, facilities would need to close their surface ash impoundments within five years and dispose of the ash (past and future) in a regulated landfill with groundwater monitoring.

2) Regulate ash disposal as a non-hazardous waste under subtitle D of RCRA. This alternative would require the facility to remove the solids and retrofit the impoundment pond with a liner to protect against groundwater contamination. Any landfill CCR disposal would require liners for new landfills and groundwater monitoring of existing landfills.

Beyond regulating coal-ash and residuals being landfilled or placed into a surface impoundment, the EPA regulation may also affect the use of the remaining coal-ash and reused or recycled residuals in products such as cement, concrete, roadbed material, drywall, etc. The EPA has indicated it will not prevent beneficial uses of the coal fly ash; however, there would be a higher cost for added ash disposal volume and a potential stigma created by regulating ash as a hazardous material, potentially resulting in lost revenue from the recycling market.

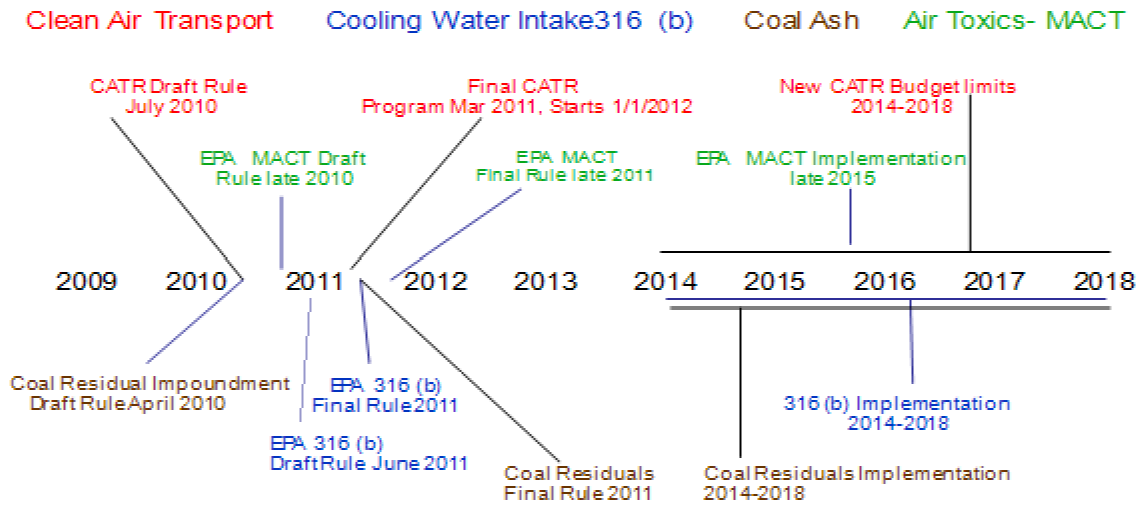
Furthermore, EPA is also considering a potential modification to the subtitle D option, called "D prime." Under the "D prime" option, existing surface impoundments would not have to close or install composite liners but could continue to operate for their useful life. Also in the "D prime" option, the other elements of the subtitle D option would remain the same. However, because no proposal has been made, this option is not included.

Timeline for Potential EPA Regulations

EPA has some flexibility in setting its compliance schedule for all potential rules except MACT (see Figure 1). Based upon current EPA schedules and historic implementation deadlines, EPA's air and solid waste regulations will likely be finalized by the end of 2011 with full compliance being anticipated by 2015–2016. The 316(b) water regulations are expected to be finalized in July 2012. It is anticipated that at least five years will be provided for compliance.

The overlapping compliance schedules for the air and solid waste regulations, along with required compliance for rule 316(b) following shortly thereafter, may trigger a large influx of environmental construction projects at the same time as new replacement generating capacity is needed. Such a large construction increase could cause potential bottlenecks and delays in engineering, permitting and construction. The risk of project delay increases if EPA decides on a compressed compliance schedule. The timing for scheduling unit outages to tie-in the environmental equipment becomes critical. Further, demand for critical equipment and supplies could potentially exceed production capacity and result in shortages and price escalations. However, surveys of labor or manufacturing were not conducted beyond the 25 percent cost increase in the Strict Case in this assessment.

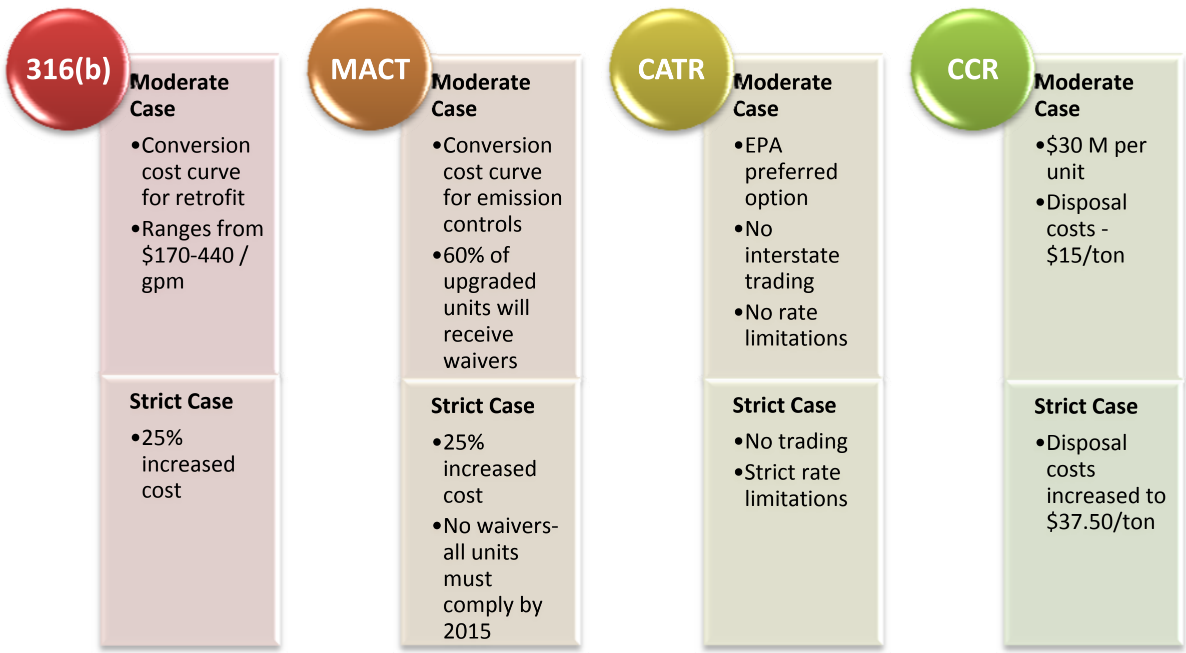
Figure 1: Timeline for Potential U.S. EPA Regulations Impacting the Electric Industry



Reliability Assessment Design

This reliability assessment used a plant-by-plant assessment. The cost factors for each unit were generic, based on its size and location and did not include engineering-level cost factors. Potential retirements and Planning Reserve Margin impacts are assessed for two cases (Moderate Case and Strict Case), for three different years (2013, 2015 and 2018), and for each regulation individually. The Combined EPA Regulation Scenario reflects the effects of the outcomes from the individual regulation cases working in aggregate. The Moderate Case assumes the costs as identified in *Appendix I: Assessment Methods and Appendix II: Environmental Regulations*. The Strict Case scenarios reflect the coupled effects of a higher increase in costs with more stringent requirements for the proposed rules. As the EPA proposed rules are not yet final, the Moderate Case and the Strict Case require expert judgment and sound assumptions on potential outcomes of the potential EPA rules.

Figure 2: Differences in Scenario Cases



In this reliability assessment, "economically vulnerable" generation capacity identifies units that would retire because of a specific potential environmental regulation. Unit retirement is assumed when the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power. In some cases, the costs imposed by the potential EPA regulations may cause "accelerated" or "early" retirement of unit generation capacity for an unknown time period. For the purpose of this assessment, replacement power costs were based on new natural gas generation capacity.[14] If the unit's retrofit costs are less than the cost of replacement power, then the unit is marked to be upgraded and retrofitted to meet the requirements of the potential environmental regulation, *i.e.*, it is not considered "economically vulnerable" for retirement. More discussion of the approach can be found in *Appendix I, Assessment Methods*.[15]

The assessment does not examine the possibility that the industry may be unable to meet its tight compliance deadlines. The Strict Case for 316(b) and MACT imposes a 25 percent cost increase to account for potential impacts if industry is unable to engineer, permit, build, or finance required retrofit environmental controls within the tight EPA compliance periods. Should multiple regulations phase-in simultaneously, replacement generation projects may encounter scheduling difficulties and scheduled retrofits may not be completed before deadlines. Where timing issues exist, waivers and extensions may be needed in order to complete a retrofit project instead of retiring the plant.

The assessment develops compliance costs based upon current average retrofit costs with existing technology market conditions. It does not assess the compliance cost risk from a run-up in labor and/or material costs caused by a construction boom from environmental control and replacement power projects. By applying average retrofit control costs by size in lieu of a detail engineering study, capital retrofit costs may be underestimated for sites with design, tight physical footprint and/or poor geologic considerations.[16]

This reliability assessment focused on measuring the potential resource implications through impacts on Planning Reserve Margins and identification of Regions/subregions where additional Regional resources may be required. The reference case for this study is based on resource projections contained in NERC's 2009 *Long-Term Reliability Assessment.*[17]

The impacts of potential EPA regulations may also have second tier effects on reliability, beyond resource adequacy. Resource deliverability, outage scheduling/construction constraints, local pockets of retirements, and transmission needs may also affect bulk power system reliability. While these issues were not studied in this assessment, the industry will need to resolve these concerns.

[14] The model does not consider potential natural gas price fluctuations.

[15] Using a different retirement method may produce different results. For instance, assessing generation on future asset performance may potentially increase the amount of capacity 'vulnerable' to retirement when economics are unprofitable, depending on the model input assumptions.

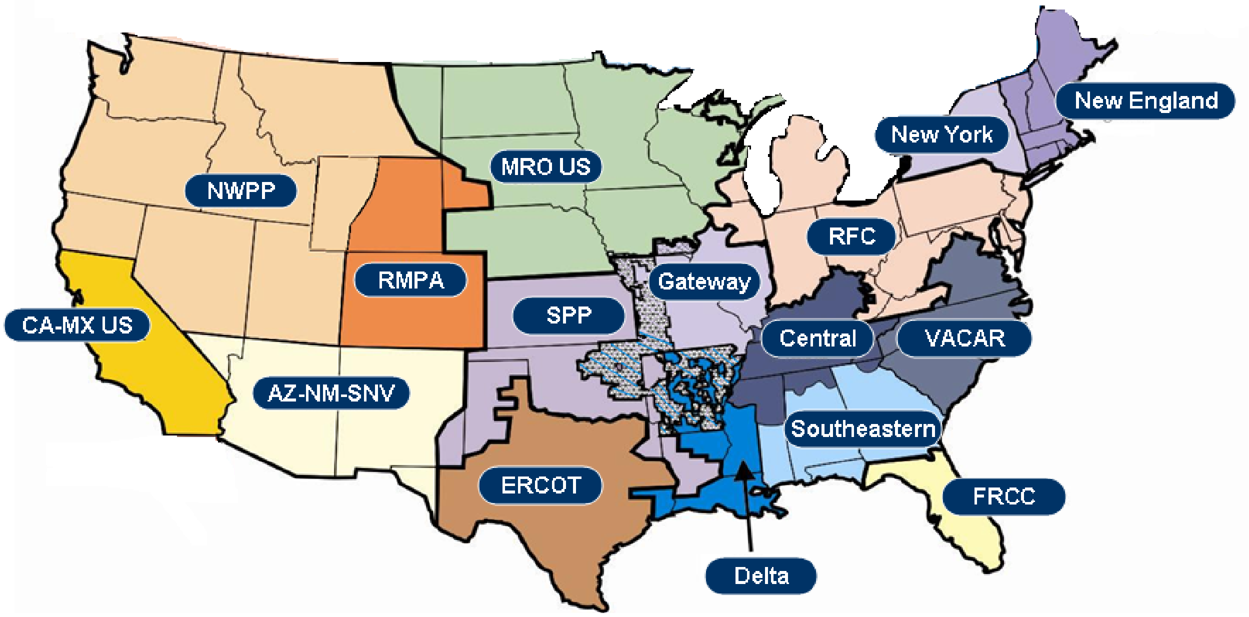
[16] This assessment did not include implementation. Because the compliance deadlines are short, generation owners may be challenged to engineer, permit, finance and build all required retrofit environmental controls within the proposed compliance periods. This may be especially challenging due to the phase-in of multiple regulations simultaneously. Further, some generation replacement projects also face similar risk of scheduling difficulties and may shutdown awaiting control completion, unless EPA grants waivers.

[17] http://www.nerc.com/files/2009_LTRA.pdf

The assessment objectives were:

1. identify potential future outcomes of EPA's active rulemaking for each of the Clean Water Act Section 316(b),[18,19] CCR, CATR, MACT and other air toxics individually and in aggregate (Combined EPA Regulation Scenario);
2. quantify and project impacts on Planning Reserve Margins for two sensitivity cases (Moderate Case and Strict Case) for each regulation (Clean Water Act Section 316(b), CCR, CATR, MACT and other air toxics), as well as their combined projected impacts for the years 2013, 2015, and 2018;
3. examine the impacts of potential unit retirement on future Regional reliability. Specifically, assess the impacts on Planning Reserve Margins to measure the relative impacts to resource adequacy across NERC Regions and Subregions (see Figure 3); and
4. provide the results to NERC's stakeholders, industry leaders, policymakers, regulators, and the public.

Figure 3: NERC US Subregions Assessed in this Report



Cost factors affect generating units as a "snapshot" in time, requiring unit operators to make the decision to finance retrofits for existing units or retire the units, replacing them with natural gas generation. Units "retire" if there are more economical replacement power alternatives available for compliance. Therefore, modeled years illustrate the scope of the U.S. bulk power industry that may be affected and the magnitude of attention required for nationwide compliance.

[18] http://www.nerc.com/files/NERC_SRA-Retrofit_of_Once-Through_Generation_090908.pdf

[19] DOE provided NERC a listing of vulnerable units (totaling approximately 240 GW). This information was supplemented by identifying those units that were expected to retire during the study timeframe, along with permitting dates. NERC reviewed the impact of either retrofitting units with existing once-through-cooling systems to closed-loop cooling systems (4 percent reduction in nameplate capacity) or unit retirements (capacity factors less than 35 percent) on NERC-U.S. and Regional capacity margins for 2012-2015.

Summary of Assumptions Used in This Report

The approach used in this assessment assumes that there are only two basic choices to consider when complying with the potential EPA regulations. The two choices are:

1. retrofit the generation unit and continue operations; or
2. retire the generation unit and replace it with a natural gas unit,

It was beyond the scope of this assessment to complete in-depth, individual plant assessment using site-specific cost factors to comply with each of the proposed EPA regulations. NERC contracted Energy Ventures Analysis Inc. (EVA)[20] to model potential reliability impacts. This model does not consider Planning Reserve Margin commitments, reliability-must-run conditions or transmission constraints. Instead, the model applied generic cost factors related to unit size and location to each unit as it was assessed. An economic approach is used that identifies which units may retire if the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power. As mentioned before, replacement power was considered to be gas-fired capacity. A more detailed discussion of the approach can be found in *Appendix I: Assessment Methods of This Report*.[21]

This assessment does not examine the additional impacts of adopting future greenhouse gas (GHG) control legislation, or other Clean Air Act requirements, including NAAQS, Regional haze/visibility, and GHG regulation,[22] national renewable portfolio standards, or other future EPA environmental rules that may lead to carbon reduction requirements. In practice, however, power suppliers are likely to consider the additional risk from uncertain future actions/rules in the U.S., such as future CO_2 legislation, when making plant investment decisions. Depending on how power suppliers quantify these risks, unit retirements may be higher than those projected in this assessment. Additionally, the report did not address any other climate change legislation.

Other assumptions affecting this reliability assessment include the following:

- Excludes plant retirements already committed or announced (13 GW) and excludes generation units not included in the NERC *2009 Long Term Reliability Assessment*[23] published in October 2009 (15 GW). Together these are equal to nearly 28 GW of capacity. These units were not included in this assessment because these units are not relied on to meet resource adequacy requirements nor do they have capacity

[20] EVA is contracted by domestic and international power producers, transportation companies, energy marketing companies and traders, industry organizations, etc.
http://evainc.com/

[21] Ibid. 11

[22] The analysis also did not address National Ambient Air Quality Standards (NAAQS) [June 2010 1-hour sulfur dioxide standard, February 2010 1-hour nitrogen dioxide standard, October 2010 revised 8-hour ozone standards (primary and possibly secondary), November 2011 revised particulate matter standards (primary and possibly secondary), the mid-2012 Transport Rule II following the October 2010 revised ozone standards, and the 2013 Transport Rule III following the November 2011 revised particulate matter standards], which could all force compliance actions by approximately 2015. The analysis also did not address regional haze. The Best Available Retrofit Technology (BART) controls in regional haze State Implementation Plans may be implemented could be required around 2015-16. The analysis did not address GHG regulation under the Clean Air Act, which will proceed in 2011 for new sources and modified sources. In step 1, starting on January 2, 2011, for sources subject to permitting for pollutants other than GHGs, new and modified sources emitting 75,000 tons per year (tpy) will be subject to Best Available Control Technology (BACT) requirements. In step 2, from July 2011 through June 2013, all sources above these thresholds – 100,000 tpy for new and 75,000 tpy for modified sources for CO2 - emissions – will be subject to Best Available Control Technology (BACT) requirements.

[23] http://www.nerc.com/files/2009_LTRA.pdf

commitments based on the *2009 Long Term Reliability Assessment.* Therefore, any capacity reduction from these units has already been considered in the *2009 Long Term Reliability Assessment* (reference case). The base generation capacity for each NERC Region/subregion is located in *Appendix III, Capacity Assessed by NERC Subregion*.

- Excludes a detailed assessment of the ability of generation owners to permit, engineer, finance, and build the required environmental controls within the short compliance timeframe. However, implementation will pose a large challenge to the equipment and construction sectors since multiple EPA programs are phased-in over the same timeframe. Compliance costs could escalate beyond the 25 percent increase of the high case (Strict Case), should the EPA require compliance within three years of the final rulemaking dates for some of the proposed rules (*i.e.*, 2014 or 2015). This situation is compounded by the large number of electric generation units that are likely to retrofit environmental controls, as well as from the competition created by replacement generation capacity projects and other heavy U.S. infrastructure projects in other sectors. A potential shortage of skilled construction labor, material shortages, and escalation of compliance costs could present challenges to meet the compressed time schedule.

- Compliance costs (capital, O&M and performance changes) are based upon current average retrofit costs with existing technology. The assessment does not evaluate the compliance cost increases resulting from a run-up in labor and material costs caused by demand increase for environmental control and replacement power projects. By applying average retrofit control costs by size in lieu of a detailed engineering study, capital retrofit costs may also underestimate the cost for sites with design, tight layout and/or poor geologic considerations. The assessment also assumes that each unit must make a decision on whether or not to retrofit with environmental controls. For example, if a plant has two units, the cost of two SCRs are used, not just one, as this is the most reliable option.

- Increased CCR disposal costs can vary widely based upon land availability, geology, and state disposal permit requirements. In this assessment, an EPA assumption of onsite disposal is adopted, and the EPA calculated disposal costs are similar to those employed. However, if onsite disposal were prohibited, the plant would incur additional costs to transport the ash and residuals to a properly permitted landfill. These costs could be significant, but cannot be estimated without a site-specific assessment. For these reasons, sensitivity comparisons were completed for CCR disposal costs.

- Power suppliers will need to bring their units offline to interconnect their new or retrofitted environmental controls. During these periods, suppliers will lose potential revenues and require use of replacement power. While the capital and O&M costs are incorporated into the compliance decision criteria, the replacement purchased power costs during these integration shutdowns have not been included and are unlikely to change or accelerate unit retirement decisions. However, these impacts would have the greatest effect on the nuclear plants that would incur the largest replacement power costs due to the duration of the retrofit outage.

- For retrofit of once-through-water cooling units, all nuclear plants are assumed to become exempted,[24] be subjected to alternative requirements as in the case of California's two operating nuclear plants,[25] or will be able to make the required investments due to the characteristics[26] of nuclear generation versus traditional fossil-fired generation.[27] Therefore, this assessment does not include any derate effects for nuclear capacity from Section 316(b). However, the maximum loss of capacity due to derate is estimated to be about 1.8 GW due to retrofit. Should 316(b) cause nuclear unit retirement, additional generation capacity loss may result.

- Generating units identified in this assessment may choose to wait until immediately prior to the compliance deadline before retiring the generation unit. This ability to delay retirement may act as a binary option causing many units to retire on December 31 prior to a January 1 deadline, and in some cases, may wait until January 1, 2018. The assumptions used for decision-making timing in this study are described in the *Some Unit Retirements Spread Through Time* section.

- All combined-cycle plants are assumed to make required investments to avoid being forced into early retirement. This may not be the case. For MACT, oil-fired units are assumed to meet emission limits through availability of suitable quality specifications of refined oil products.

- The assessment excludes any fossil-fuel market price or supply risks that are created by a large shift in the power generation mix from environmental compliance measures (*e.g.*, a shift from coal to natural gas fuel). Delivered natural gas and coal prices are fixed and do not change based on the level of retirements or the level of new replacement capacity that may be required.

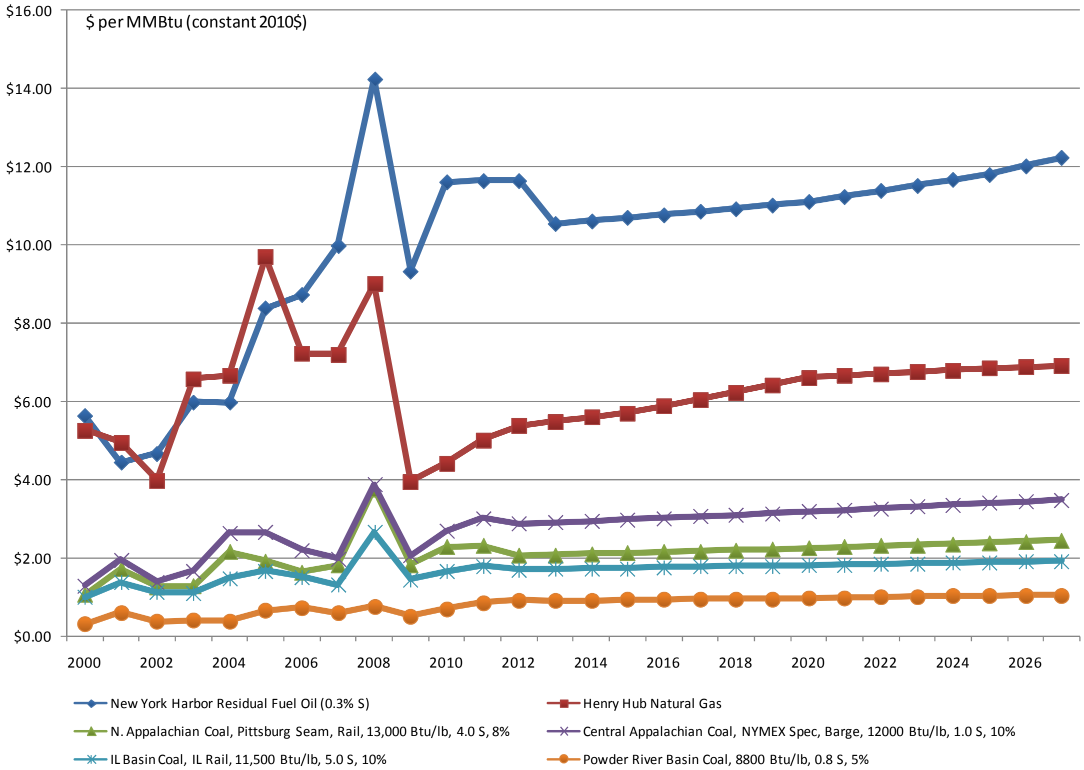
- If a coal plant is retired under this method, there is nothing to prevent a secondary, after-the-fact decision. For instance, a coal unit may convert into a biomass-based unit, or convert to natural gas burners and continue operating as a steam plant. In addition, plant owners may decide to invest in construction at existing construction sites after retirement. Such decisions are beyond the scope of this assessment.

- The assessment did not examine or model the use of other sorbent injection technologies (*e.g.*, trona) as an alternative. For trona, capital costs would be lower, but higher operating costs would result. Limestone scrubbers are the norm in the United States, although, this technology has been used at older plants where owners did not want to make the larger capital investment. Further, while some future plants may opt for trona vs. a limestone scrubber, a majority of plants (greater than 97 percent) will use limestone.

- Delivered natural gas, coal and oil prices were based on the forecasts of EVA as of May 2010. Ten-year forward averages are applied for 2013, 2015 and 2018. Varying these price assumptions may produce different results. The base wholesale fuel price forecasts are depicted in Figure 4 on an undelivered basis.

[24] http://www.snl.com/InteractiveX/article.aspx?CDID=A-10616386-10806&KPLT=2
[25] http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf
[26] *e.g.*, Lower GHG emissions, longer in-service operations, higher availability, baseload resource
[27] DOE, 2008 http://www.oe.energy.gov/DocumentsandMedia/Cooling_Tower_Report.pdf

Figure 4: Wholesale Fuel Price Assumptions Used for This Assessment



S=Sulfur Content

Some Unit Retirements Spread Through Time

Because the implementation of multiple EPA regulations is tightly stacked through time, a large number of retirements may occur in the same year, requiring new resources to offset the capacity reductions. To simulate a more realistic and expected outcome, in certain instances, some of the retirement and waivers were simulated earlier in time, rather than reflecting all retirements in one year, such as in 2015 or 2018, depending on the regulation. These results are included in the scenario of the four potential regulations. In addition:

- **Section 316(b) and Coal Combustion Residuals:** As the EPA implementation deadlines are expected to be January 1, 2018, no units theoretically would need to be retired until 2018. However, this assessment assumes that 20 percent of designated units are retired in each year from 2013 through 2017 for the Moderate Case and the Strict Case. To select which individual units are simulated to retire, each designated plant's economics are ranked from the most expensive to least expensive production costs. The units with the most expensive plant costs were retired first for Section 316(b) and CCR. Conversely, the units with the lowest cost plant economics were upgraded first.

- **MACT:** For the Moderate Case only, 60 percent of units that are designated to upgrade environmental controls by 2015 receive waivers as of January 1, 2015. The most expensive 20 percent of units are retired by 2014 (no effects as of January 1, 2013), and then the next most expensive 20 percent of units are retired by 2015. Also conversely, the units with the lowest cost plant economics are upgraded first when the highest cost plants are retired.

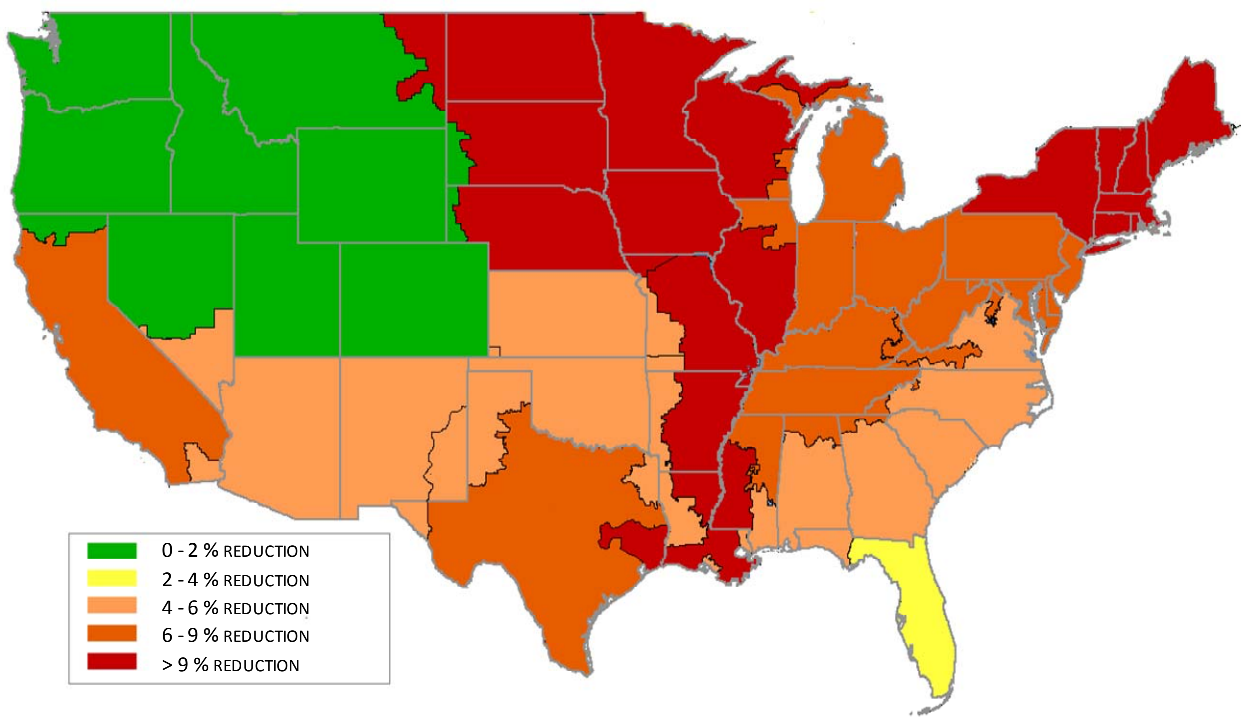
- **CATR:** The Strict Case simulated the highest 40 percent of units were retired by 2013 and the 40 lowest cost units were retrofitted by 2013.

Scenario Results

U.S. power suppliers will assess the impact of all future environmental requirements when making their environmental compliance decisions. Even in the absence of future GHG legislation, the combination of the four potential EPA rules may have significant economic impacts on generating units, potentially affecting the reliability of bulk power system as measured by significant declines in Planning Reserve Margins. Based on the design of this assessment, the overall total compliance cost impact would place between 40 and 69 GW of existing capacity (441-761 units) as "economically vulnerable" for accelerated retirement due to more cost efficient compliance alternatives by 2018. On-site stations loads for equipment operation derate the net generating capacity of the retrofitted units by 6.7-7.4 GW. The overall affect would be a total of 46-76 GW of capacity reductions significantly affecting Planning Reserve Margins if no additional resources are built beyond what is included in the *2009 NERC Long-Term Reliability Assessment* plans (see Figure 5). In many Regions/subregions, Planning Reserve Margins fall below the NERC Reference Margin Level, indicating the need for more resources.

The potential retirement and deratings affect resource portfolios in all eight NERC Regions, but especially in the ERCOT, MRO, NPCC, SERC, and NPCC Regions. The most significant individual impacts are due to the Section 316(b) regulation, then MACT, CATR and finally CCR. However, the Combined EPA Regulation Scenario has the greatest impact to reliability.

Figure 5: 2018 Reduction in Adjusted Potential Capacity Resources due to the Combined EPA Regulation Scenario



Scenario Results

Scenario Results

Section 316(b) Cooling Water Intake Structures

In the Moderate Case scenario, the Section 316(b) rule alone could potentially increase the unit production costs above replacement power costs at 347 stations, retiring 33 GW of current generating capacity. This retired generating capacity was spread across the rule implementation period (2014-2018). The majority of the "economically vulnerable" units are older oil/gas steam units (253 units with 30 GW of capacity). An additional 94 coal steam units (capacity of 2.5 GW) are also "economically vulnerable". The remaining 688 would also incur a five GW capacity derating to support increases in station loads. Table 1 shows how these retirements and capacity derating penalties affect the NERC subregions for the year 2015 while 2018 impacts are shown in Table 2. For this assessment, no units were affected in 2013. As shown, SERC-Delta, RFC, WECC-CA, and ERCOT account for 65 percent of the unit retirements.

Table 1: 316(b) Impacts - 2015

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	187	556	743	187	752	939
FRCC	69	68	137	69	68	137
MRO	340	450	789	338	479	817
NPCC-NE	0	1,061	1,061	0	1,061	1,061
NPCC-NY	22	958	980	22	958	980
RFC	988	763	1,751	954	763	1,717
SERC-Central	275	0	275	275	0	275
SERC-Delta	82	1,774	1,856	82	1,774	1,856
SERC-Gateway	288	266	555	288	266	555
SERC-Southeastern	60	224	284	52	224	276
SERC-VACAR	101	92	193	120	92	212
SPP	113	501	614	113	531	644
WECC-CA	0	786	786	0	786	786
WECC-AZ-NM-SNV	0	24	24	0	25	25
WECC-NWPP	36	39	75	36	39	75
WECC-RMPA	13	36	49	13	64	77
TOTAL	2,575	7,597	10,172	2,551	7,881	10,432

Should the cooling tower conversion costs be 25 percent higher than prior engineering studies indicated ($300/gpm versus $240/gpm), an additional 17 units (four GW) could retire resulting in a total of 37 GW.

Section 316(b) marginally affects coal units in comparison to its effects on oil/gas steam units (*i.e.*, 92–93 percent of capacity). In the Strict Case, most of the incremental retirements are older oil/gas steam units located in WECC-CA, NPCC, SERC-Delta, ERCOT, and RFC, ranked from highest to lowest. For the coal units, most "economically vulnerable" capacity is in RFC. The "economically vulnerable" capacity in the Strict Case is 12 percent greater than in the Moderate Case.

Table 2: 316(b) Impacts - 2018						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	322	5,055	5,377	316	5,295	5,611
FRCC	177	862	1,039	164	1,367	1,531
MRO	400	1,259	1,659	400	1,264	1,664
NPCC-NE	194	2,504	2,698	180	2,904	3,084
NPCC-NY	347	3,011	3,357	327	3,618	3,946
RFC	1,532	5,503	7,035	1,526	5,661	7,187
SERC-Central	388	71	459	388	71	459
SERC-Delta	282	5,524	5,806	282	5,524	5,806
SERC-Gateway	296	526	822	295	543	838
SERC-Southeastern	209	469	678	209	469	678
SERC-VACAR	378	664	1,042	377	689	1,066
SPP	143	933	1,076	141	994	1,135
WECC-CA	227	5,055	5,283	182	6,881	7,063
WECC-AZ-NM-SNV	5	773	778	5	773	778
WECC-NWPP	40	129	169	40	129	169
WECC-RMPA	16	184	200	16	184	200
TOTAL	4,954	32,522	37,476	4,848	36,366	41,214

These estimates are slightly less, but comparable, to the October 2008 DOE study, *Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generating Units* that resulted in approximately 40 GW of potential retirements. Some differences may be attributable to this study excluding more already announced generating unit retirements (more than 28 GW) and incorporating a more comprehensive retirement replacement cost method (versus applying a capacity factor criterion).

National Emissions Standards for Hazardous Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT)

National Emissions Standards for Hazardous Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT) will apply to all existing and future coal and oil fired steam capacity. The Moderate Case scenario rulemaking varies for MACT emission rate limitations by coal type. This assessment assumes that the EPA deadline is January 1, 2015. However, in the Moderate Case, only 40 percent of units that will eventually retire do so by January 1, 2015. As EPA has no authority under the Clean Air Act to grant waivers for a MACT standard, one of these two[28] conditions must occur:

- the EPA Administrator (or state with program approval) grants an extension of one additional year, finding more time is "necessary for the installation of controls"– §112(i)(3)(B). This may occur on a case-by-case basis; or

- a Presidential exemption for a period of not more than two years is granted, assuming the President finds (1) the technology to implement such standard is not available and (2) it is in the national security interests to do so. Additional one year extensions are also available –§112(i)(4).

The Moderate Case outcome is that there are no forced retirements as of January 1, 2013. Twenty percent of units retire by January 1, 2014, reaching 40 percent of units retired by January 1, 2015 followed by an additional 20 percent in each subsequent year, such that all designated units are retired by January 1, 2018. In 2015, the impact of the Moderate Case is roughly 2.1 GW of existing coal-fired capacity (59 units) "economically vulnerable" for retirement; another 0.8 GW may be derated. The figure triples by 2018 to 6.6 GW of coal capacity that may be retired and 1.8 GW derated for a total impact of 8.4 GW.

The Strict Case assumes that no waivers are granted and all electric generation units must be in compliance by January 1, 2015. Obtaining these waivers appears difficult; the EPA granted a sector-wide extension of one year only once, in a marine MACT rule. The Strict Case also assumes that all retirements occur in the two years leading up to the deadline, *i.e.*, during 2013 and 2014, with none as of January 1, 2013. The Strict Case also increases compliance costs by 25 percent. These two assumptions significantly change the assessment results, such that by 2015 there is 14.9 GW of existing coal-fired capacity (228 units) "economically vulnerable" for early retirement and 2.8 GW derated for a total of 17.6 GW. The 2015 result carries over into 2018.

MACT depicts the greatest variation between the two cases of all the EPA regulations. There is a 12 GW difference in capacity loss between the Moderate Case and the Strict Case by 2015. There is a nine GW difference by 2018. Distribution of this capacity by Region/subregion for 2015 and 2018 are shown in Table 3 and Table 4.

[28] Under section 202(c) of the Federal Power Act, the Secretary of Energy has authority when an emergency exists "by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to order such temporary interconnection of facilities or generation, delivery, interchange, or transmission of electric energy as in his/her judgment "will best meet the emergency and serve the public interest." However, section 202(c) does not specifically mention EPA or the Clean Air Act.

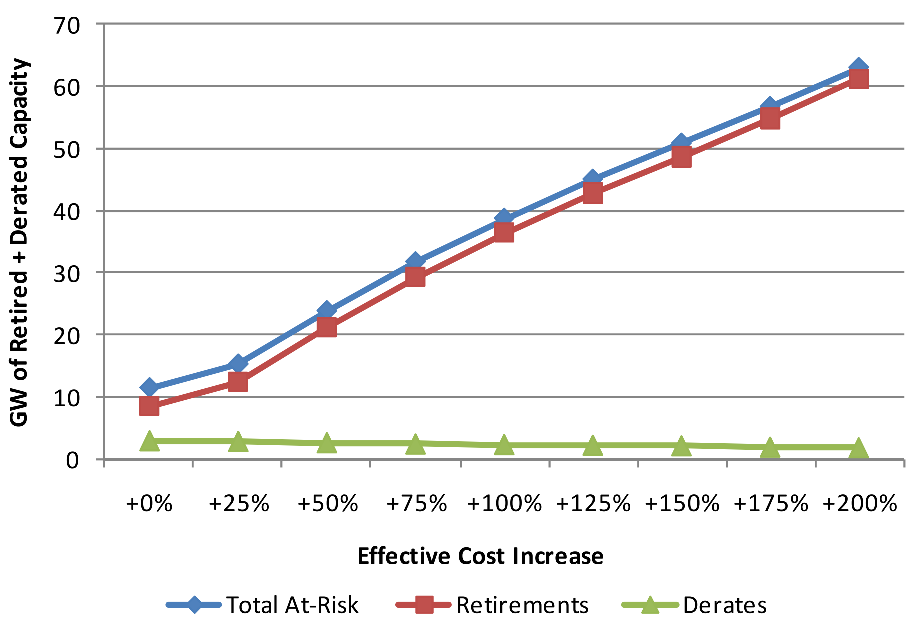
Table 3: MACT Impacts - 2015						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	73	0	73	73	0	73
FRCC	0	0	0	78	121	199
MRO	125	202	327	144	764	908
NPCC-NE	0	0	0	32	616	647
NPCC-NY	0	0	0	16	694	710
RFC	103	1,061	1,164	1,060	5,493	6,553
SERC-Central	61	71	132	305	1,000	1,305
SERC-Delta	69	18	87	69	95	164
SERC-Gateway	84	35	119	110	365	475
SERC-Southeastern	33	140	173	337	1,208	1,545
SERC-VACAR	0	465	465	255	2,649	2,905
SPP	127	0	127	130	52	181
WECC-CA	0	0	0	3	0	3
WECC-AZ-NM-SNV	49	0	49	49	1,580	1,629
WECC-NWPP	72	39	111	73	129	202
WECC-RMPA	10	0	10	10	100	110
TOTAL	806	2,032	2,838	2,746	14,865	17,611

Table 4: MACT Impacts - 2018						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	73	0	73	73	0	73
FRCC	16	0	16	78	121	199
MRO	144	708	853	144	764	908
NPCC-NE	25	0	25	32	616	647
NPCC-NY	16	58	74	16	694	710
RFC	514	2,540	3,055	1,060	5,493	6,553
SERC-Central	167	184	351	305	1,000	1,305
SERC-Delta	70	46	116	69	95	164
SERC-Gateway	100	96	196	110	365	475
SERC-Southeastern	227	140	367	337	1,208	1,545
SERC-VACAR	132	970	1,102	255	2,649	2,905
SPP	130	52	181	130	52	181
WECC-CA	3	0	3	3	0	3
WECC-AZ-NM-SNV	49	1,580	1,629	49	1,580	1,629
WECC-NWPP	73	129	202	73	129	202
WECC-RMPA	10	100	110	10	100	110
TOTAL	1,750	6,602	8,352	2,746	14,865	17,611

The impacts could be more severe if costs escalate due to tighter implementation timelines of three years and the large number of plants (840 units) that may need to upgrade their environmental controls at the same time. This could require additional new generation and expanded use of existing lower emission generation like natural gas. In circumstances in which power plant retirements trigger localized reliability concerns, EPA can follow established precedent, including use of consent decrees, to permit continued operation for reliability purposes only, pending necessary upgrades or generation additions.

A sensitivity comparison was completed for the 2015 Strict Case for MACT accounting for the compressed implementation timeline (see Figure 6). The risk that generation units will retire simply due to insufficiently available third party engineering services is not modeled in the sensitivity test. Because the 2015 Strict Case already includes a 25 percent cost premium, the sensitivity comparisons were completed at cost increase intervals of 25 percent from 0 percent up to 200 percent. As a result, retirements increased at an approximate linear rate from a low of 11.4 GW (retirements of 8.5 GW and derated capacity of 2.9 GW) at no cost increase up to 63 GW (retirements of 61.2 GW and derated capacity of 1.8 GW) at a 200 percent cost increase.

Figure 6: Sensitivity of Retirements Plus Derated Capacity as a Function of Higher Assumed Costs due to the MACT Regulation



Clean Air Transport Rule (CATR)

Starting in 2012, the CATR will apply to fossil fuel units with greater than 25 MW capacity that are located in 31 states. Although EPA provided three different options in July 2010, the EPA preferred option was selected for the Moderate Case. An analysis of this option found that the rule would have the greatest impact in the state utilities that relied heavily upon purchased allowances for compliance with their Acid Rain program and CAIR program obligations. By significantly limiting the use of out-of-state utility purchases and/or banked allowances after 2013, some utilities would be forced to retrofit FGD and SCR emission controls on their larger units or retire to comply. The oil and gas steam units would remain largely untouched because of their limited emissions. As described earlier in this report, these reductions would be concentrated to a few states.

The extent of retirements triggered by CATR is heavily linked to:

1. the flexibility provided to affected sources to avoid reductions in smaller emitting stations by retrofitting controls in larger emitting units (through allowance trading); and
2. the final budget state cap (the July 2010 draft emission caps are interim limits that will be reduced further as stricter future ambient fine particulate and ozone standards are adopted). The EPA preferred option (Moderate Case) would result in the retirement of five coal-fired units (538 MW) by 2013 and 18 coal-fired units (2,740 MW) by 2015 (see Tables 5 and 6).[29]

Table 5: CATR Impacts - 2013

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	64	0	64
FRCC	0	0	0	4	0	4
MRO	0	0	0	162	155	318
NPCC-NE	0	162	162	1	0	1
NPCC-NY	0	0	0	0	0	0
RFC	1	376	377	191	781	972
SERC-Central	11	0	11	87	71	158
SERC-Delta	0	0	0	99	29	128
SERC-Gateway	0	0	0	94	35	129
SERC-Southeastern	5	0	5	145	130	275
SERC-VACAR	0	0	0	47	548	594
SPP	0	0	0	110	26	136
WECC-CA	0	0	0	0	0	0
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	17	538	555	1,004	1,775	2,779

[29] Impacts from CATR would begin in 2014. For this report, only 2013, 2015, and 2018 were assessed.

Scenario Results

Alternatively, EPA could elect to pursue emission rate limitations on the coal-fired units. This approach would provide no ability to trade at all and units would be forced to retrofit the needed controls or retire. With the impending changes in NAAQS unknown, the Strict Case assumes that EPA will adopt much stricter rate limits on all coal-fired capacity that only can be met through post combustion controls. Given the large demand created for emission controls, the capital cost will likely increase by 25 percent or more from current levels. Overall, 86 coal units (5,221 MW) would have their operating costs pushed above new replacement capacity and force their retirement. Although tied to the changing of the NAAQS, these retirements would likely occur in or before 2015. Further impacts, past 2015, are not expected to materialize.

Table 6: CATR Impacts - 2015

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	91	0	91
FRCC	0	0	0	16	0	16
MRO	0	33	33	216	1,007	1,223
NPCC-NE	0	162	162	14	370	384
NPCC-NY	0	0	0	22	50	73
RFC	67	1,667	1,734	552	2,192	2,744
SERC-Central	15	0	15	154	136	290
SERC-Delta	0	0	0	127	29	155
SERC-Gateway	0	878	878	171	35	206
SERC-Southeastern	60	0	60	258	230	488
SERC-VACAR	0	0	0	130	1,056	1,186
SPP	0	0	0	202	115	317
WECC-CA	0	0	0	0	0	0
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	142	2,740	2,882	1,952	5,221	7,173

The analysis affects coal units only and the most significant impact of the Strict Case occurs in RFC, SERC and MRO, which have the most remaining coal plants that require upgrading in the 31 states and the District of Columbia affected by CATR

Coal Combustion Residuals (CCR) Disposal Regulations

A distribution of the coal units "economically vulnerable" from the potential coal combustion byproducts rule is shown in Table 7 for both the Moderate Case and the Strict Case scenarios in 2018. As shown, the additional capital and annual operating cost increases under both scenarios would trigger the retirement of only four coal units with capacity of 287 MW in the Moderate Case and 12 units with capacity of 388 MW in the Strict Case. This "economically vulnerable" coal-fired capacity is located in three to four SERC subregions and MRO. Under the estimated compliance timeline, these coal unit retirements would likely not occur until the 2015—2018 period. A larger number of coal units are affected in the Strict Case, since the Moderate Case affects only those plants using ponds for ash disposal, whereas the Strict Case assumes that all coal plants will need to store coal combustion byproducts in a lined landfill.

Table 7: CCR Impacts - 2018

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	0	0	0
FRCC	0	0	0	0	0	0
MRO	0	0	0	0	83	83
NPCC-NE	0	0	0	0	0	0
NPCC-NY	0	0	0	0	0	0
RFC	0	0	0	0	0	0
SERC-Central	0	71	71	0	71	71
SERC-Delta	0	0	0	0	18	18
SERC-Gateway	0	86	86	0	86	86
SERC-Southeastern	0	130	130	0	130	130
SERC-VACAR	0	0	0	0	0	0
SPP	0	0	0	0	0	0
WECC-CA	0	0	0	0	0	0
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	0	287	287	0	388	388

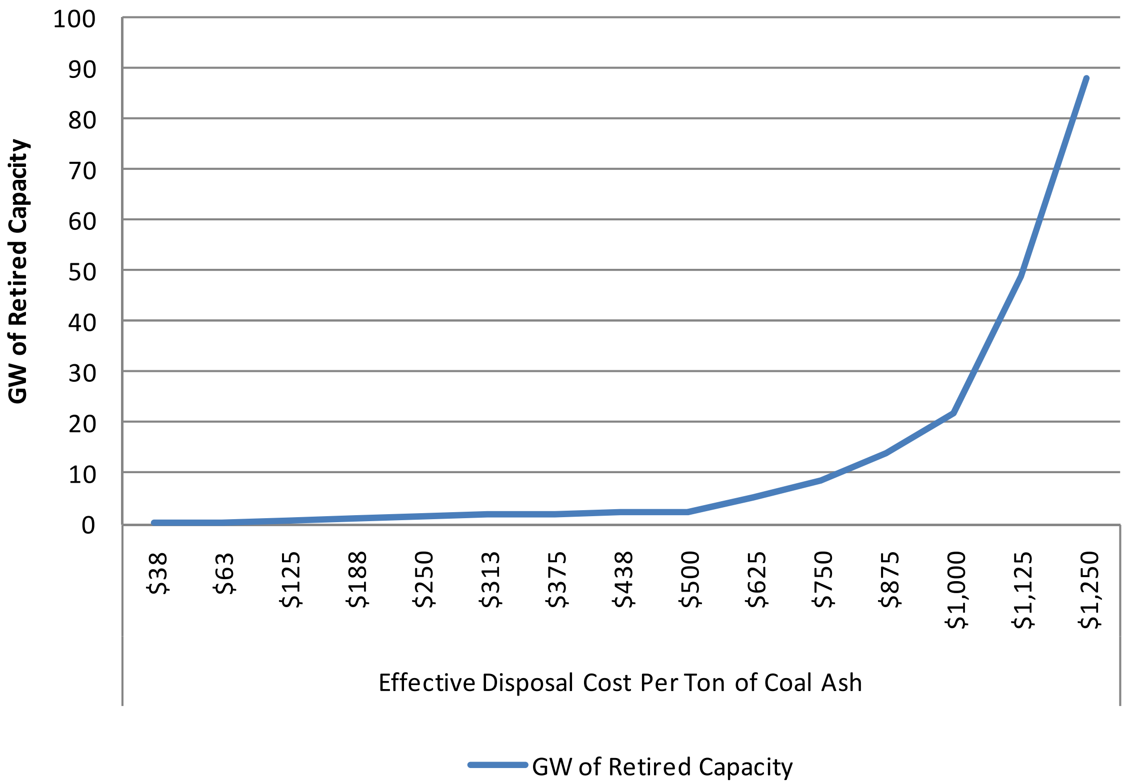
These estimates are substantially less than the EOP Group Study titled *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal Fired Utilities* that resulted in 35 GW of "economically vulnerable" coal-fired capacity. Some differences are likely to be attributable to this assessment excluding already announced generating unit retirements (more than 28 GW) and incorporating a more comprehensive retirement replacement cost method (versus applying a unit size criterion).

Because of the large difference in results, sensitivity comparisons were conducted to determine how the number of "economically vulnerable" units would vary under higher disposal cost assumptions. Disposal costs can vary significantly based upon suitable land availability and state landfill requirements. Like EPA, this assessment assumed that suitable landfill sites could be found, permitted and operated near to existing coal plants. If no suitable sites can be permitted, power suppliers may be forced to transport their residuals to appropriately permitted offsite landfills and pay tipping fees that could increase disposal costs.

Scenario Results

In lieu of conducting site-specific assessment, a sensitivity comparison was completed across a wide range of ash disposal costs from $37.50 up to $1,250 per ton (see Figure 7). The economic retirements slope gradually upward from 0.3 to 2.1 GW as costs increase from $37.50 to $500 per ton, then retirements begin to jump significantly with amounts reaching 22 GW at $1,000 per ton, and exponentially increase to 49 GW at $1,125 and nearly 88 GW at $1,250 per ton. However, the costs are believed to be well contained within the flat slope portion of the line on the far left side. However, the additional costs that may become associated with distance removal of the hazardous substance to existing certified landfills could drive costs upward.

Figure 7: Sensitivity of Retirements as a Function of Higher Assumed Coal-Ash Disposal Costs due to Coal Combustion Residuals regulations



Combined EPA Environmental Rulemaking

The reliability impact of each rule outlined above reflects the cost and retirement decisions for each individually. However, power suppliers will likely make their retirement decisions based upon compliance costs for the combination of all future environmental requirements. Although some environmental control overlap exists between the CATR and MACT (*i.e.*, for FGD and SCR retrofits), most compliance costs are expected to be additive between the different EPA rules.

The cumulative effect of the four potential EPA rules is provided in Tables 8, 9, and 10 for each of the three years assessed. In 2015, anywhere from 31–70 GW of existing fossil fuel capacity (351–678 generation units; beyond the 28 GW of retirements already announced and not included in NERC's Long Term Reliability Assessment) are "economically vulnerable" for retirement from these four potential EPA rules. Additionally the 273–700 units of continuing operation will be derated by a total of 2.4-7.3 GW from the increased parasitic loads from the control operation. The projected retirements are significantly lower in 2013 and significantly higher for the Moderate Case in 2018.

Table 8: Combined EPA Regulations Impacts - 2013

	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	0	0	0	91	0	91
FRCC	0	0	0	16	0	16
MRO	0	0	0	216	1,007	1,223
NPCC-NE	0	162	162	12	532	545
NPCC-NY	0	0	0	19	258	278
RFC	1	376	377	541	2,876	3,418
SERC-Central	11	0	11	153	211	364
SERC-Delta	0	0	0	127	29	155
SERC-Gateway	0	0	0	171	35	206
SERC-Southeastern	5	0	5	258	230	488
SERC-VACAR	0	0	0	128	1,163	1,291
SPP	0	0	0	58	89	147
WECC-CA	0	0	0	144	26	170
WECC-AZ-NM-SNV	0	0	0	0	0	0
WECC-NWPP	0	0	0	0	0	0
WECC-RMPA	0	0	0	0	0	0
TOTAL	17	538	555	1,934	6,457	8,391

For the combined potential EPA rulemaking, the retirement and derating penalties are concentrated in five NERC Regions/subregions for the 2015 Moderate Case -- SERC, NPCC, RFC, ERCOT, and WECC, ranked in order of highest to lowest. For the 2015 Strict Case, the rank order is SERC, RFC, WECC, NPCC, and finally ERCOT.

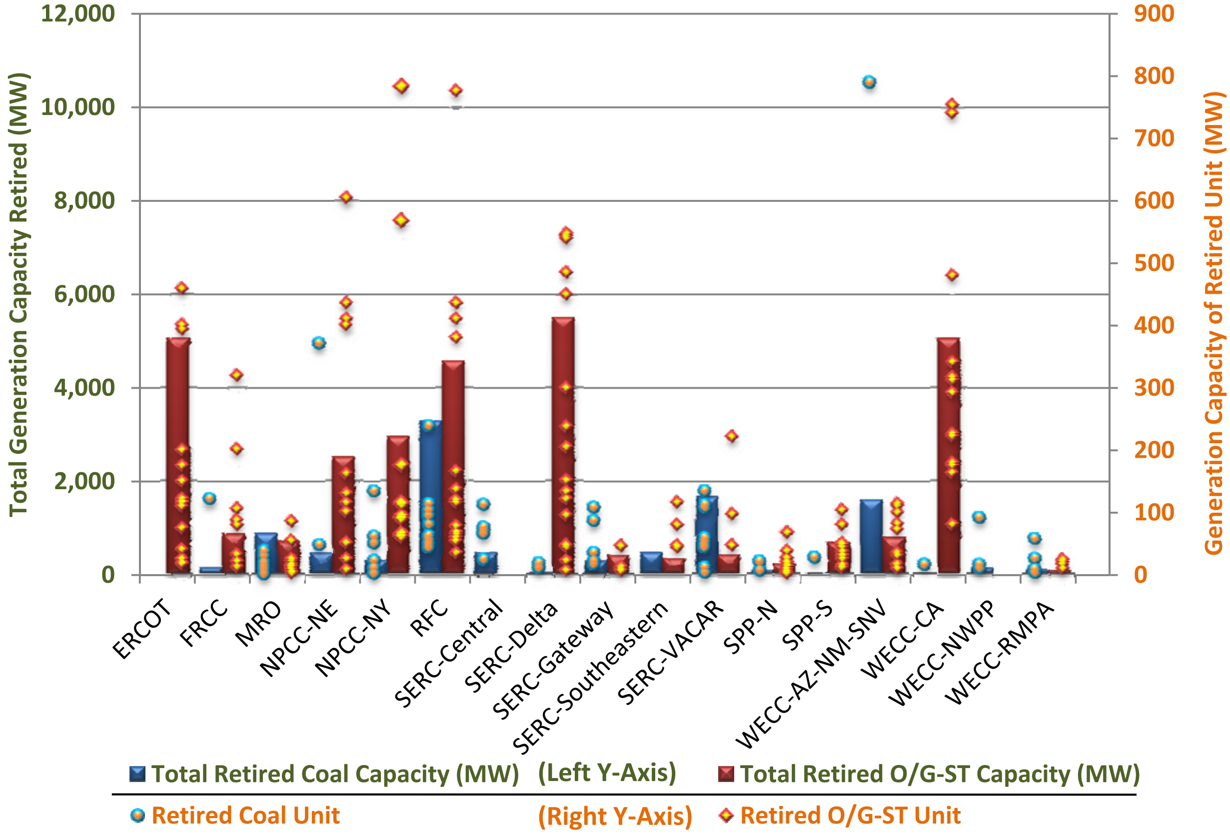
Table 9: Combined EPA Regulations Impacts - 2015						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	246	5,055	5,301	480	5,295	5,775
FRCC	71	862	933	239	1,488	1,727
MRO	319	1,259	1,578	612	4,424	5,036
NPCC-NE	0	2,504	2,504	169	3,938	4,107
NPCC-NY	35	3,011	3,046	309	4,759	5,068
RFC	607	4,890	5,497	2,224	16,423	18,648
SERC-Central	237	71	308	509	4,546	5,055
SERC-Delta	113	5,524	5,636	465	5,803	6,268
SERC-Gateway	113	526	639	413	3,902	4,315
SERC-Southeastern	140	469	609	537	3,132	3,669
SERC-VACAR	132	915	1,047	515	5,042	5,557
SPP	198	831	1,029	428	2,149	2,577
WECC-CA	0	3,560	3,560	195	6,452	6,647
WECC-AZ-NM-SNV	49	773	822	54	2,353	2,407
WECC-NWPP	108	129	237	113	129	242
WECC-RMPA	25	184	208	25	225	251
TOTAL	2,394	30,563	32,957	7,289	70,059	77,349

Table 10: Combined EPA Regulations Impacts - 2018						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
ERCOT	366	5,055	5,421	480	5,295	5,775
FRCC	188	983	1,171	239	1,488	1,727
MRO	534	1,553	2,087	612	4,424	5,036
NPCC-NE	196	2,970	3,166	169	3,938	4,107
NPCC-NY	353	3,239	3,592	309	4,759	5,068
RFC	1,965	7,848	9,813	2,266	15,451	17,717
SERC-Central	541	445	986	509	4,546	5,055
SERC-Delta	352	5,541	5,892	465	5,803	6,268
SERC-Gateway	390	694	1,084	442	3,299	3,741
SERC-Southeastern	423	781	1,204	537	3,132	3,669
SERC-VACAR	476	2,066	2,542	515	5,042	5,557
SPP	271	972	1,243	428	2,149	2,577
WECC-CA	230	5,055	5,285	182	6,947	7,130
WECC-AZ-NM-SNV	54	2,353	2,407	54	2,353	2,407
WECC-NWPP	113	129	242	113	129	242
WECC-RMPA	27	184	210	25	225	251
TOTAL	6,479	39,867	46,346	7,348	68,979	76,327

This assessment models both coal and oil/gas-steam unit capacity retirement. Figures 8 and 9 depict total capacity loss for both unit types, as well as the size of individual retired units by Region for the 2018 Moderate and Strict Case assessments.

In Figures 8 and 9, each retired unit is plotted on the scatter chart based on unit size (Right Y-Axis). In some cases, data points for units with the same unit size (MW) may overlap and be hidden. The blue and red bars (Left Y-Axis) show the total retired capacity by subregion. Overall, a majority of the retired units are less than 200 MW.

Figure 8: 2018 Moderate Case
Units Retired for Combined Scenario



The Strict Case (see Figure 9) has a significant impact on coal units in the MRO, RFC, SERC-Central, SERC-Gateway, SERC-Southern, and SERC-VACAR Regions/subregions.

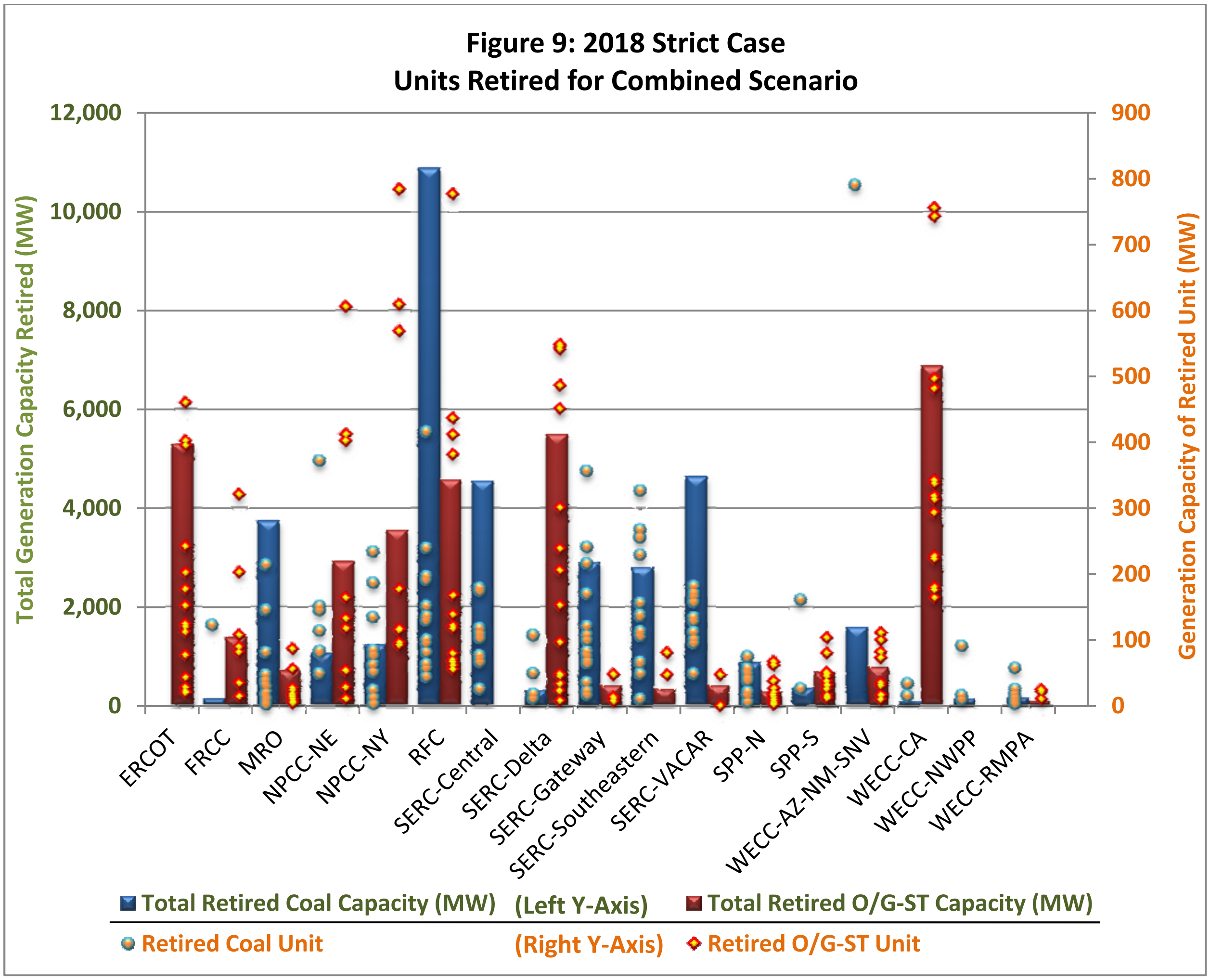
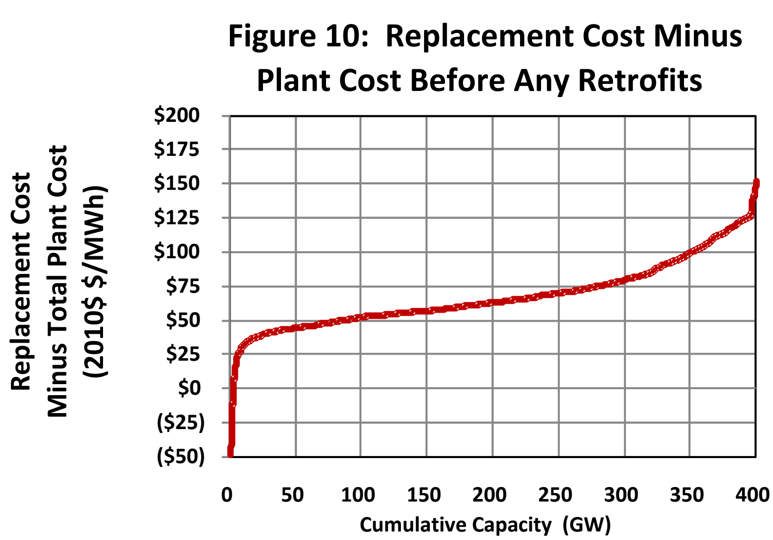


Figure 10 illustrates the model's representation of the differential between two items: the cost of a new gas plant and today's operating/ongoing costs for any new investment that has incremental costs, regardless of its source or mandate.



Reliability Assessment

Impacts on Bulk Power System Adequacy

Early retirement of multiple units in the short-run can stress the bulk power system if plans are not in place to add resources. This can affect both short- and long-term planning strategies and reduce Planning Reserve Margins.[30] Sufficient Planning Reserve Margins must be maintained to provide reliable electric service. With fewer resources, flexibility is reduced and the risk of a capacity shortage may increase, unless additional resources are available. Where Planning Reserve Margins fall below zero, there is a basic inability to serve load with available resources.

For this assessment, NERC studied the effects on Planning Reserve Margins from both unit retirement (assuming retired capacity is not replaced) and retrofits, which cause capacity reductions due to increased station loads to support emission controls or new intake structures. Planning Reserve Margins are presented using Deliverable Capacity Resources and Adjusted Potential Capacity Resources.[31] The assessment of effects to Planning Reserve Margins does not consider the ability of the electric power industry to replace retired capacity. Each modeled year portrays a "snapshot" of potential effects caused by the potential EPA regulations, rather than an ongoing timeline of retrofits and retirements. Models do not account for units coming out of retirement due to future conditions. The demand and resource projections from the *2009 Long-Term Reliability Assessment* are used as the reference case and can be found in *Appendix III, Data Tables*.

Models for each year in all cases show identical Planning Reserve Margin reductions for Deliverable and Adjusted Potential Capacity Resources, indicating that the potential EPA regulations have little to no effect on Existing-Other, Future Other, and Conceptual Resources. Therefore, comparative analysis of Deliverable Capacity Resources and Adjusted Potential Capacity figures indicates the magnitude of future resource additions required to maintain future reserve requirements.

Resources from these ten-year projections are reduced to form the scenario cases (Moderate Case and Strict Case—previously described in the report) and calculate the resulting Planning Reserve Margins. This reliability assessment includes a comparison of the impacts on Planning Reserve Margin for the years 2013, 2015, and 2018 based on the 2009 reference case. The resulting Planning Reserve Margin was compared to the NERC Reference Margin Level to determine if

[30] Planning Reserve Margin is designed to measure the amount of generation capacity available to meet expected demand in the planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of resource adequacy. Planning Reserve Margin is the difference between available capacity and peak demand, normalized by peak demand (as a percentage) needed to maintain reliable operation while meeting unforeseen increases in demand (*e.g.* extreme weather) and/or unexpected outages of existing capacity. From a planning perspective, Planning Reserve Margin trends identify whether capacity additions are keeping up with demand growth.

[31] Deliverable Capacity Resources (DCR)—defined as Existing-Certain and Net Firm Transactions plus Future-Planned capacity resources plus net transactions—and Adjusted Potential Capacity Resources (APCR)—defined as the sum of Deliverable Capacity Resources, Existing-Other Resources, Future-Other Resources (reduced by a confidence factor), Conceptual Resources (reduced by a confidence factor), and net transactions—account for future generation capacity planned for in the reference case.[31] DCR represents existing generation that has been identified as "Certain" plus future firm resources. APCR prevents this assessment from being overly conservative in two ways: 1) Conceptual resources measure industry's future response towards maintaining Planning Reserve Margins and 2) APCR represents the portion of the interconnection queue that is historically built. A range of resource projections is identified and evaluated from these two values in this assessment.

Reliability Assessment

more resources are needed in the scenario case (see Table 11).[32] For the resource adequacy assessment, NERC chose a range of resource categories to evaluate Planning Reserve Margins for this scenario. The range includes Deliverable Capacity Resources on the low-end and Adjusted Potential Capacity Resources on the high-end. Refer to the *Terms Used in This Report* section for detailed definitions regarding supply/resource categories.

Table 11: NERC Reference Margin Levels	
ERCOT	12.5%
FRCC	15.0%
MRO	15.0%
NPCC	
New England	15.0%
New York	16.5%
RFC	15.0%
SERC	
Central	15.0%
Delta	15.0%
Gateway	12.7%
Southeastern	15.0%
VACAR	15.0%
SPP	13.6%
WECC	
AZ-NM-SNV	17.8%
CA-MX US	22.3%
NWPP	16.3%
RMPA	17.1%

Overall, impacts on Planning Reserve Margins and the need for more resources is a function of the compliance timeline associated with the potential EPA regulations. Up to a 78 GW reduction of coal, oil, and gas-fired generation capacity is identified for retirement during the ten-year period of this scenario. For the Moderate Case, this occurs in 2018; however, in the Strict Case similar reduction occurs in 2015. The reduction in capacity significantly affects projected Planning Reserve Margins for a majority of the NERC Regions and subregions. Potentially significant reductions in capacity within a five-year period may require heightened concentration towards the addition of resources. For the United States as a whole, the Planning Reserve Margin is significantly reduced up to 9.3 percentage points in the Strict Case.

Additionally, more transmission resources may be needed as the industry responds to resolve identified capacity deficiencies. As replacement generation is constructed, new transmission may be needed to interconnect new generation. Additionally, existing generation that may not be deliverable due to transmission limitations may need enhancements to the transmission system in order to allow firm and reliable transmission service.

While NERC did not model deliverability or stability impacts to the transmission system (second tier effects) in this assessment, constructing new transmission or refurbishing existing transmission may be required. Transmission system enhancements and reconfiguration may be necessary in some areas, which may create additional timing issues as transmission facilities will take relatively longer to construct than generation.

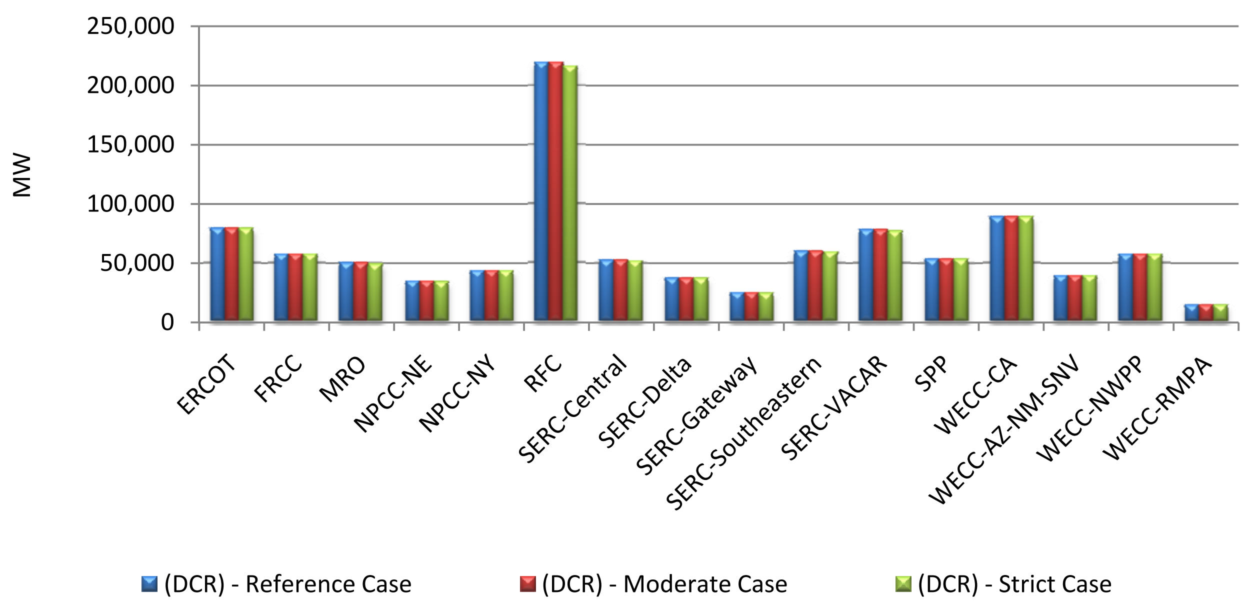
[32] NERC's Reference Reserve Margin Level is equivalent to the Target Reserve Margin Level provided by the Region/subregion's own specific margin based on load, generation, and transmission characteristics as well as regulatory requirements. If not provided, NERC assigned 15 percent Reserve Margin for thermal systems and 10 percent for predominately hydro systems.

Resource Adequacy Assessment Results: 2013

There are virtually no impacts to Planning Reserve Margins in the short term (2013). CATR is the only regulation that affects units in 2013. MRO, New England, RFC, SERC-Gateway, and SERC-Southeastern are the only Regions/subregions affected by CATR in the Moderate Case—ERCOT, FRCC, and all SERC subregions are affected in the Strict Case.

However, when CATR is modeled in the Combined EPA Regulation Scenario, the Strict Case results in a coal-fired capacity reduction of 8,391 MW by 2013 (see Figure 12). Overall, this amount does not appear to be significant and represents less than one percent of total capacity resources across the United States, but represents just fewer than 100 electric generation plants. The increased capacity reduction is a result of the increased costs being considered by generator owners, not only to comply with CATR, but with the 316(b), MACT, and CCR regulations. Because of these reductions, Planning Reserve Margins are reduced slightly in the affected Regions/subregions. The MRO Planning Reserve Margin decreases the most (about 2.7 percentage points when considering both the Deliverable and Adjusted Potential Planning Reserve Margins) to approximately 19 percent (see Figure 13 and 14). Other affected Regions/subregions include NPCC-New England and RFC, which result in a net Planning Reserve Margin reduction of less than two percentage points. There is no change to the Moderate Case when comparing the results of CATR modeled separately and the Combined EPA Regulation Scenario.

Figure 11: 2013 Summer Peak Deliverable Capacity Resources (DCR) Impacts of Combined EPA Regulation Scenario



In MRO and the SERC-Southeastern subregion, Deliverable Planning Reserve Margin is below the NERC Reference Margin Level in both scenario cases. However, this is also true when considering the Reference Case. This indicates more resources may be needed regardless of impacts from potential EPA regulations. These two subregions must rely on Adjusted Potential Capacity Resources to meet the NERC Reference Margin Level in 2013.

Figure 12: 2013 Summer Peak Adjusted Potential Capacity Resources (APCR) Impacts of Combined EPA Regulation Scenario

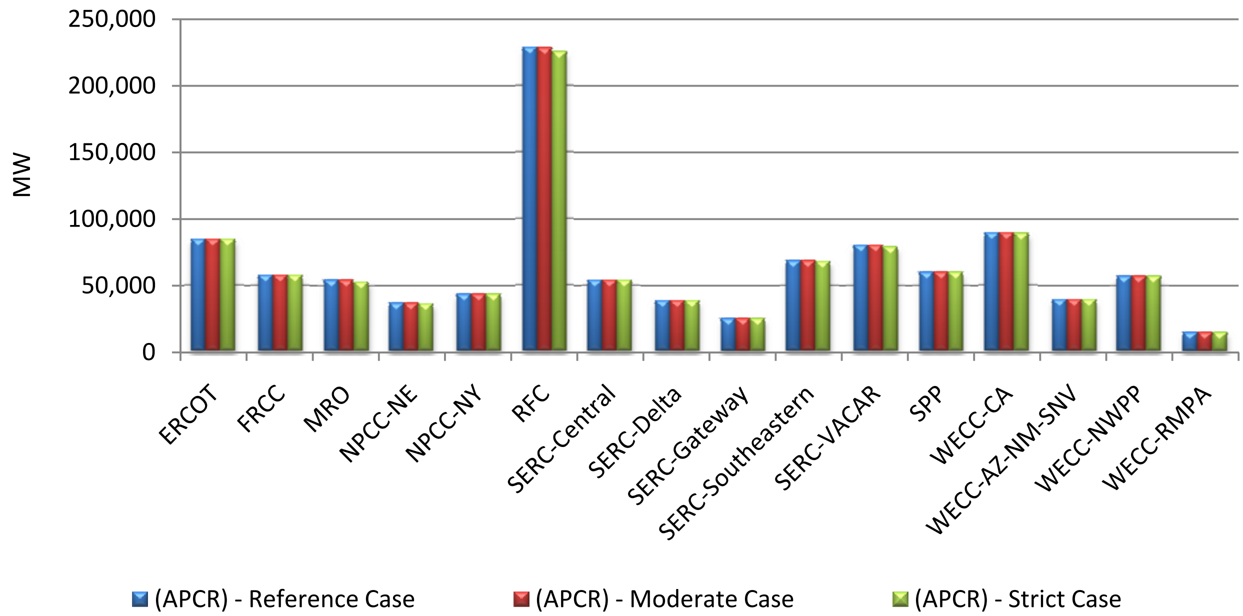


Figure 13: 2013 Summer Peak Deliverable Capacity Resources (DCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

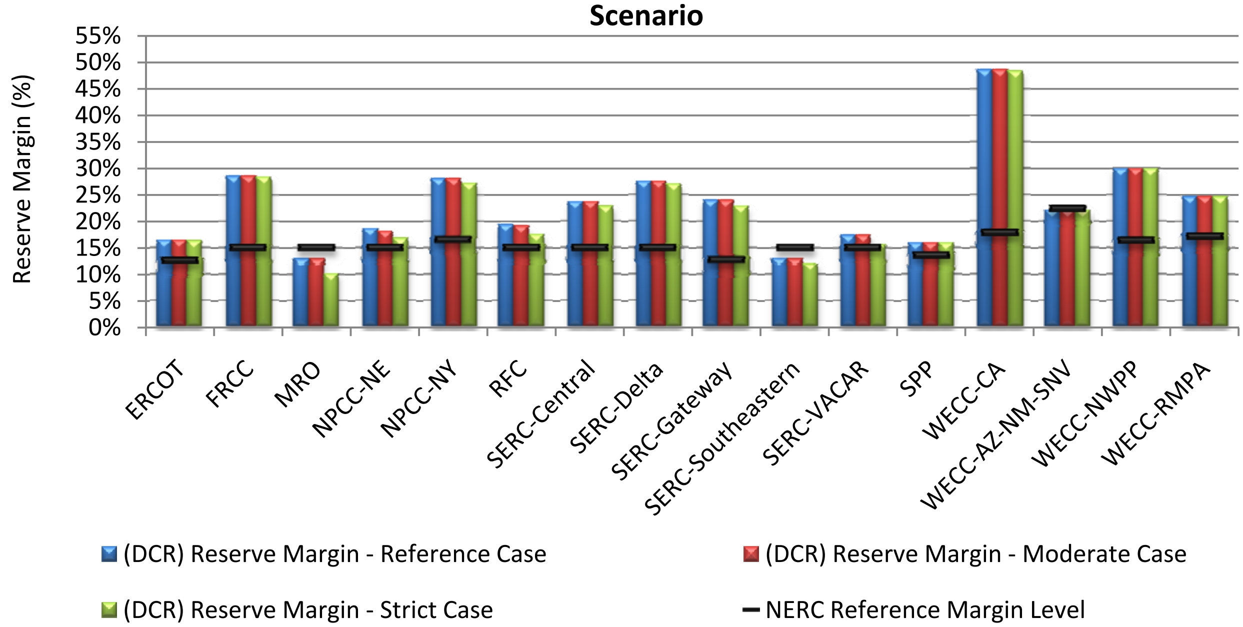


Figure 14: 2013 Summer Peak Adjusted Potential Capacity Resources (APCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

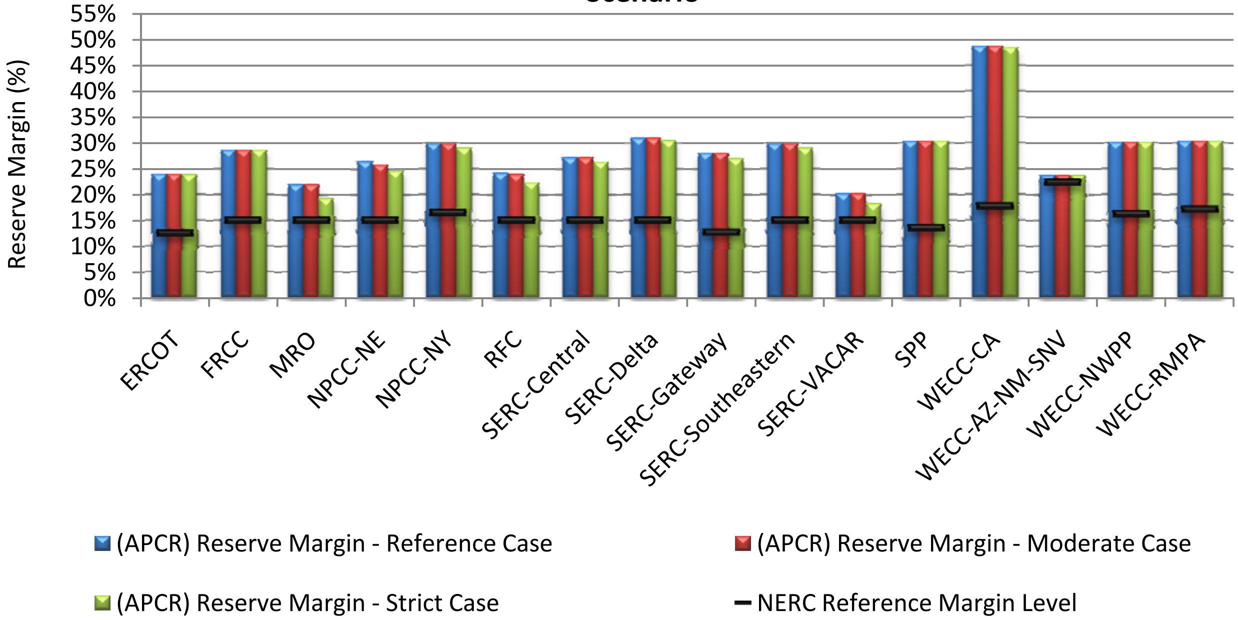


Table 12: Combined Impacts - 2013

	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% — 23.9%	0.0 — 0.0	16.3% — 23.8%	-0.1 — -0.1
FRCC	28.6% — 28.6%	0.0 — 0.0	28.5% — 28.5%	0.0 — 0.0
MRO	12.9% — 22.1%	0.0 — 0.0	10.1% — 19.3%	-2.7 — -2.7
NPCC-NE	18.0% — 25.9%	-0.6 — -0.6	16.7% — 24.6%	-1.9 — -1.9
NPCC-NY	28.1% — 29.8%	0.0 — 0.0	27.3% — 29.0%	-0.8 — -0.8
RFC	19.2% — 24.0%	-0.2 — -0.2	17.6% — 22.4%	-1.9 — -1.9
SERC-Central	23.6% — 27.2%	0.0 — 0.0	22.8% — 26.4%	-0.9 — -0.9
SERC-Delta	27.5% — 30.9%	0.0 — 0.0	27.0% — 30.4%	-0.5 — -0.5
SERC-Gateway	24.0% — 28.0%	0.0 — 0.0	22.9% — 27.0%	-1.0 — -1.0
SERC-Southeastern	13.0% — 29.8%	0.0 — 0.0	12.1% — 28.9%	-0.9 — -0.9
SERC-VACAR	17.5% — 20.3%	0.0 — 0.0	15.5% — 18.3%	-1.9 — -1.9
SPP	15.9% — 30.3%	0.0 — 0.0	15.9% — 30.3%	0.0 — 0.0
WECC-CA	48.6% — 48.6%	0.0 — 0.0	48.4% — 48.4%	-0.3 — -0.3
WECC-AZ-NM-SNV	22.1% — 23.7%	0.0 — 0.0	22.1% — 23.7%	0.0 — 0.0
WECC-NWPP	29.9% — 30.1%	0.0 — 0.0	29.9% — 30.1%	0.0 — 0.0
WECC-RMPA	24.7% — 30.3%	0.0 — 0.0	24.7% — 30.3%	0.0 — 0.0
TOTAL	22.3% — 27.7%	-0.1 — -0.1	21.4% — 26.7%	-1.0 — -1.0

Reliability Assessment

Resource Adequacy Assessment Results: 2015

For the modeled year 2015, the assessment results have a greater impact on Planning Reserve Margin. Most notably, the Combined Proposed EPA Regulations Scenario shows considerable reductions, reducing Planning Reserve Margins across the United States during the next five years.

As previously discussed, the Moderate Case and the Strict Case differ in key assumptions. In 2015, capacity reductions range from 33 GW (Moderate Case) to 77 GW (Strict Case). For the Moderate Case, ERCOT, RFC, and the SERC-Delta Regions/subregions are the most affected, each with approximately a 5,500 MW reduction in capacity (Figure 16). For the Strict Case, RFC capacity is reduced by 16.4 GW.

Figure 15: 2015 Summer Peak Deliverable Capacity Resources (DCR) Impacts of Combined EPA Regulation Scenario

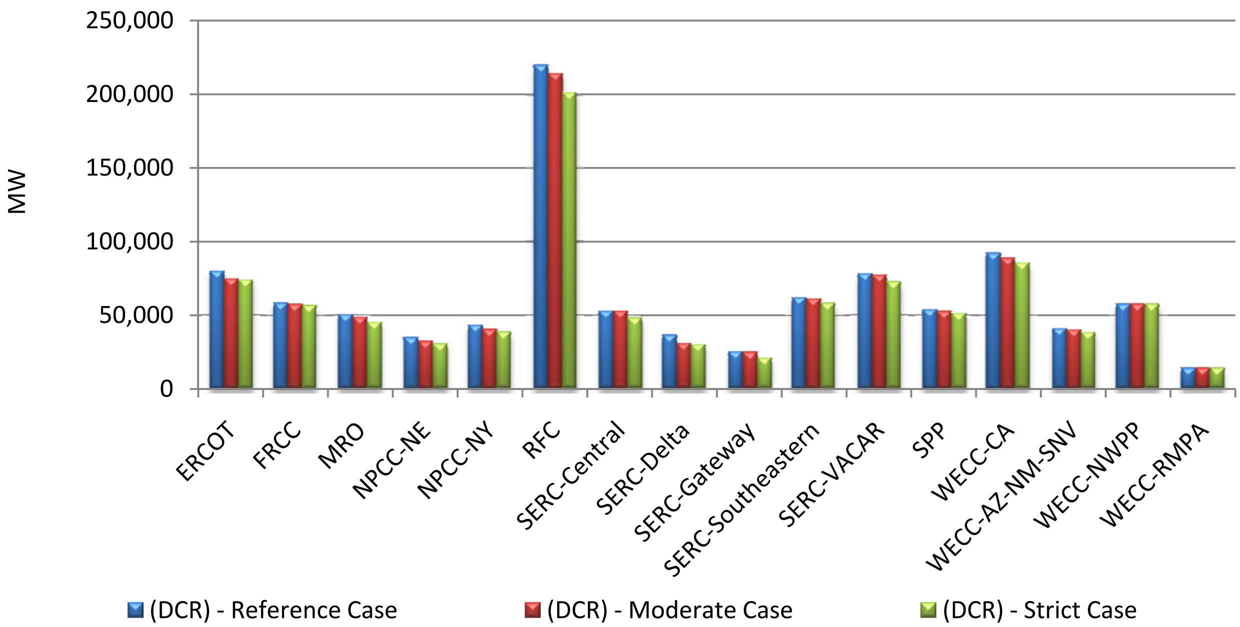
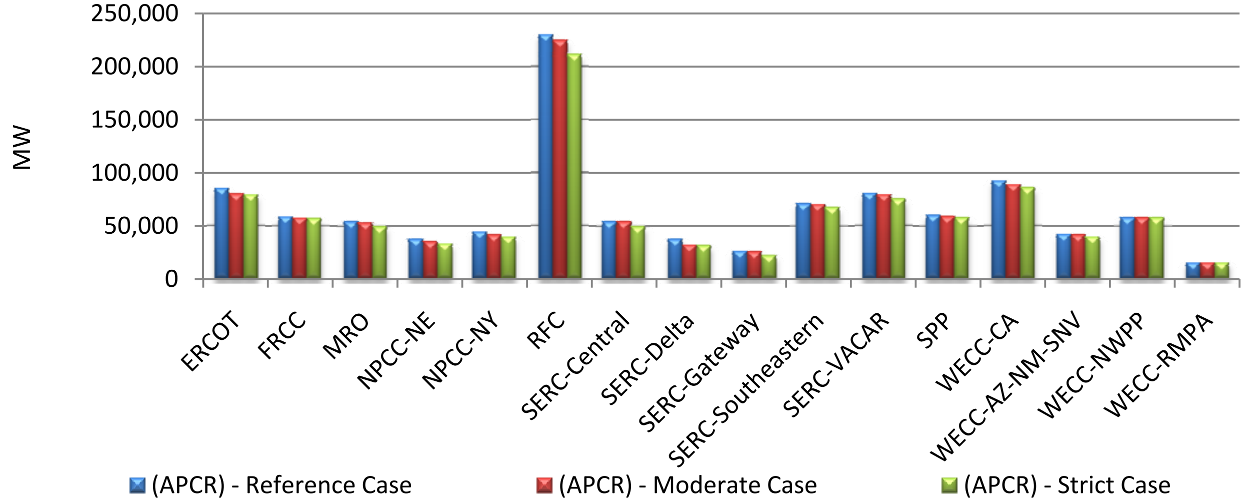
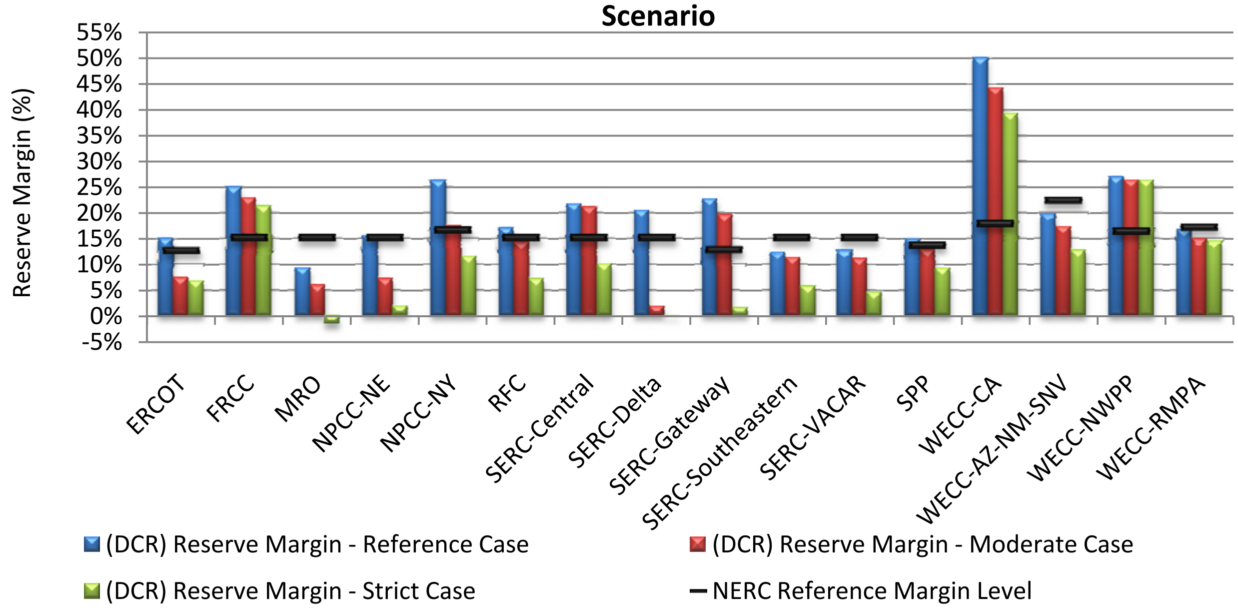


Figure 16: 2015 Summer Peak Adjusted Potential Capacity Resources (APCR) Impacts of Combined EPA Regulation Scenario



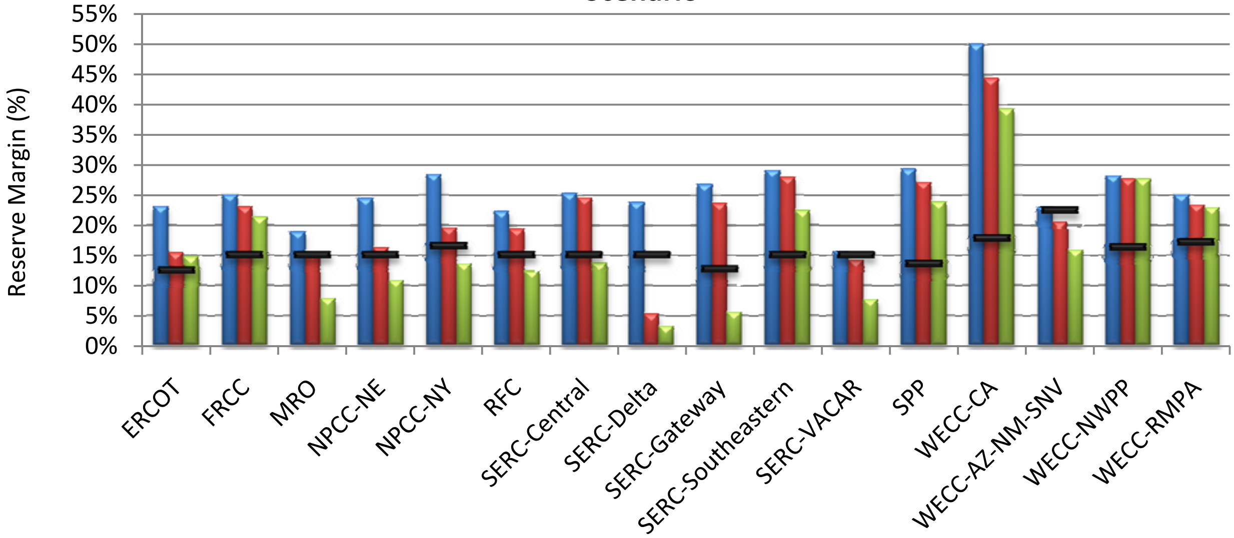
For the Moderate Case, a 3.2 percent reduction in overall capacity results in Planning Reserve Margin reductions for a majority of the NERC Regions/subregions. Accordingly, the SERC-Central, SERC-Southeastern, SERC-VACAR, WECC-NWPP, and WECC-RMPA subregions show less than a two percentage point reduction in Planning Reserve Margin. When considering the Deliverable Planning Reserve Margin a majority of the Regions/subregions fall below the NERC Reference Margin Level in 2015 for both cases. In MRO, Deliverable Planning Reserve Margins fall below zero in the Strict Case (Figure 17). Additionally, because of a 15 percent reduction in SERC-Delta capacity resources, the Planning Reserve Margin is reduced to 1.9 percent (Deliverable—see Figure 17) and 5.2 percent (Adjusted Potential—see Figure 18). In this scenario, more resources will be needed in the SERC-Delta subregion under the Moderate Case assumptions.

Figure 17: 2015 Summer Peak Deliverable Capacity Resources (DCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario



Reliability Assessment

Figure 18: 2015 Summer Peak Adjusted Potential Capacity Resources (APCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario



For the Strict Case, a 7.2 percent reduction in overall capacity results in significant Planning Reserve Margin reductions for all NERC Regions and subregions, except the WECC subregions of NWPP and RMPA. Planning Reserve Margins are significantly due to over a nine percent of capacity resources in MRO, NPCC-New England, NPCC-New York, SERC-Central, SERC-Delta, and SERC-Gateway. When considering Deliverable Planning Reserve Margins, nearly all Regions/subregions fall below the NERC Reference Margin Level (see Figure 17).Additionally, these Regions/subregions are below NERC's Reference Margin Levels under the Strict Case assumptions, indicating reductions in those Regions'/subregions' ability to maintain sufficient reserve levels. Most notably, SERC-Delta has a 3.1 percent Planning Reserve Margins in 2015. Additionally, capacity reductions in NPCC-New England, SERC-Gateway, and SERC-VACAR result in Planning Reserve Margins below 10 percent. In these Regions/subregions, more resources will be needed for this scenario.

The impacts to Planning Reserve Margins are highly dependent on which resources are projected to be in-serving in the Reference Case. As such, Adjusted Potential Capacity Resources Planning Reserve Margins are not as impacted as Deliverable Capacity Resources Planning Reserve Margin. Therefore, in order to help mitigate resource adequacy issues, Adjusted Potential Resources (which include Conceptual Resources), which carry a level of uncertainty, may be needed to meet the NERC Reference Margin Level. However, as indicated above, even these additional resources may not be sufficient.

Table 13: Combined Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	7.5% — 15.4%	-7.7 — -7.7	6.8% — 14.7%	-8.4 — -8.4
FRCC	23.0% — 23.0%	-2.0 — -2.0	21.3% — 21.3%	-3.7 — -3.7
MRO	5.9% — 15.5%	-3.5 — -3.5	-1.7% — 7.9%	-11.0 — -11.0
NPCC-NE	7.2% — 16.2%	-8.3 — -8.3	1.8% — 10.8%	-13.6 — -13.6
NPCC-NY	17.4% — 19.5%	-8.9 — -8.9	11.5% — 13.6%	-14.8 — -14.8
RFC	14.2% — 19.4%	-2.9 — -2.9	7.2% — 12.4%	-9.9 — -9.9
SERC-Central	21.0% — 24.5%	-0.7 — -0.7	10.1% — 13.6%	-11.6 — -11.6
SERC-Delta	1.9% — 5.2%	-18.6 — -18.6	-0.2% — 3.1%	-20.6 — -20.6
SERC-Gateway	19.6% — 23.6%	-3.1 — -3.1	1.5% — 5.5%	-21.3 — -21.3
SERC-Southeastern	11.3% — 27.9%	-1.1 — -1.1	5.7% — 22.4%	-6.6 — -6.6
SERC-VACAR	11.1% — 14.2%	-1.5 — -1.5	4.6% — 7.6%	-8.0 — -8.0
SPP	12.7% — 27.1%	-2.2 — -2.2	9.3% — 23.8%	-5.5 — -5.5
WECC-CA	44.3% — 44.3%	-5.8 — -5.8	39.3% — 39.3%	-10.8 — -10.8
WECC-AZ-NM-SNV	17.3% — 20.6%	-2.4 — -2.4	12.6% — 15.9%	-7.1 — -7.1
WECC-NWPP	26.5% — 27.6%	-0.5 — -0.5	26.5% — 27.6%	-0.5 — -0.5
WECC-RMPA	14.9% — 23.2%	-1.7 — -1.7	14.6% — 22.9%	-2.1 — -2.1
TOTAL	16.1% — 21.7%	-4.0 — -4.0	10.8% — 16.4%	-9.3 — -9.3

Reliability Assessment

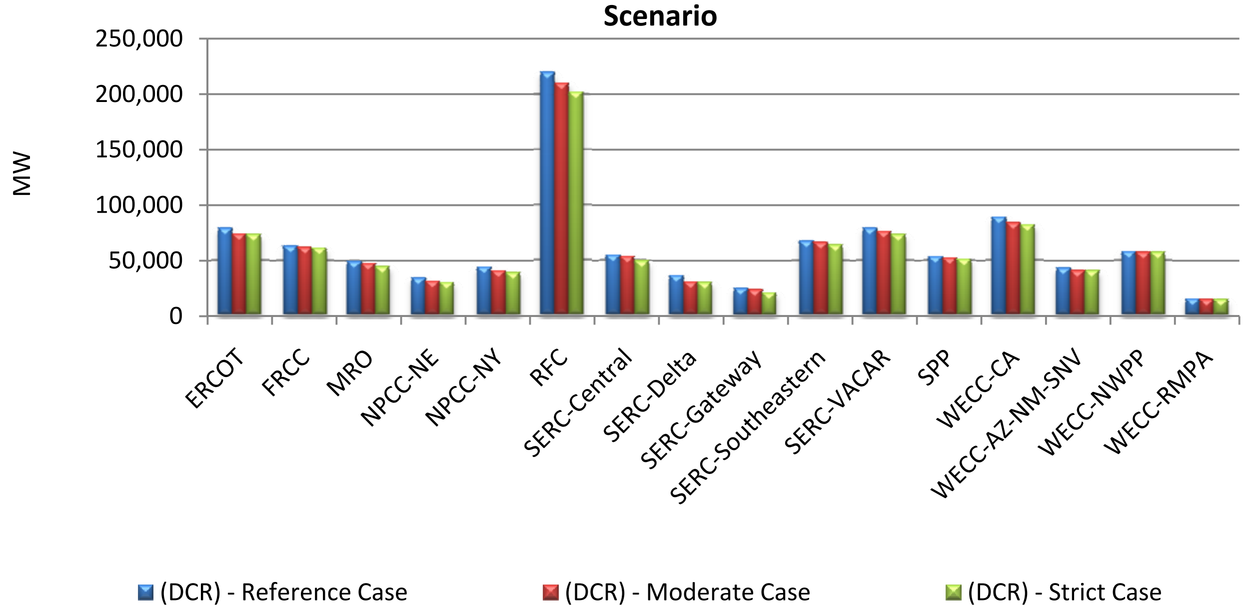
Resource Adequacy Assessment Results: 2018

Further reductions in capacity resources and Planning Reserve Margins are the results in 2018. Most notably, the Combined EPA Regulations Scenario shows considerable reductions, effectively reducing Planning Reserve Margins across the United States within the next eight years.

The Combined Regulation Scenario shows the most notable capacity resources reductions. As previously discussed, the Moderate Case and the Strict Case differ in key assumptions that have been made to the model. In 2018, capacity reductions range from 46 GW (Moderate Case) to 76 GW (Strict Case).[33] For the Moderate Case, RFC is the more affected Region with just under a 10 GW reduction in capacity resources, followed by ERCOT, SERC-Delta, and the WECC-CA Regions/subregions, each with approximately a 5.5 GW capacity reduction (Figure 15).

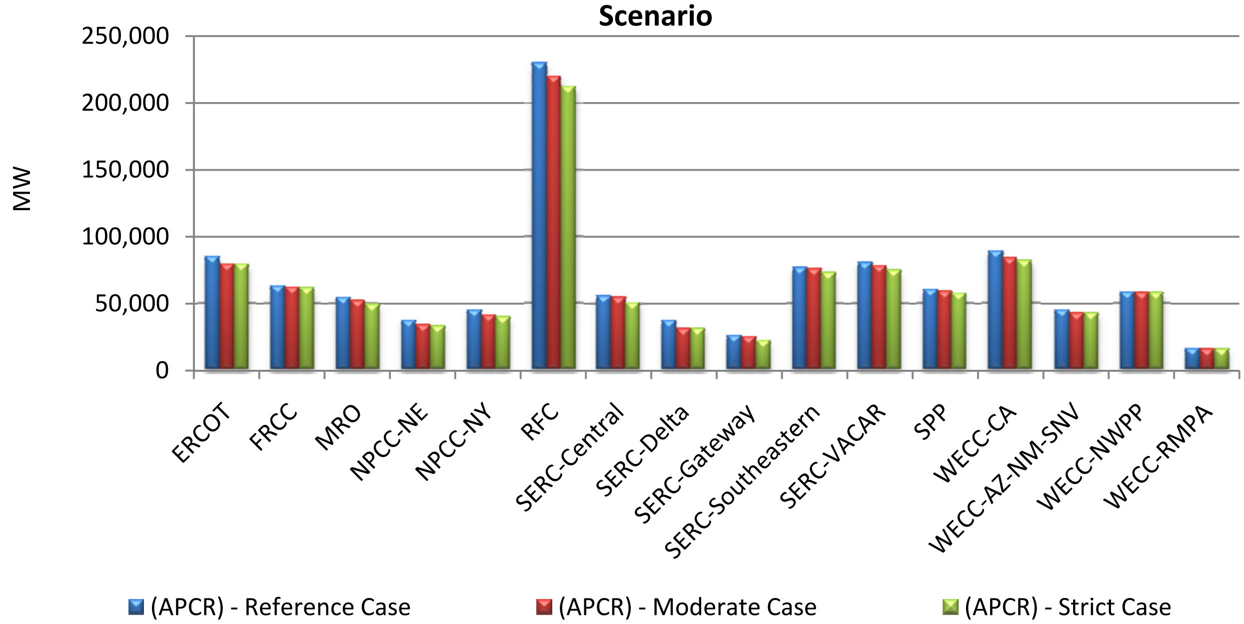
For the Strict Case, RFC capacity is reduced by 17.7 GW. With the exception of FRCC, WECC-NWPP, and WECC-RMPA, all Regions/subregions show at least a five percent reduction in capacity resources. MRO, NPCC-New England, NPCC-New York, SERC-Central, SERC-Delta, and SERC-Gateway all show at least a nine percent reduction in capacity resources; SERC-Delta shows a 17 percent reduction, suggesting more resources will be needed in these areas.

Figure 19: 2018 Summer Peak Deliverable Capacity Resources (DCR) Impacts of Combined EPA Regulation Scenario



33 The total reductions for the 2018 Combined Regulation-Strict Case (76 GW) is less than the total reductions for the 2015 Combined Regulation-Strict Case (77 GW) due to slightly higher gas prices assumed for the year 2018. Therefore, plants may opt to retrofit rather than purchase replacement generation. Each modeled year portrays a "snapshot" of potential effects caused by the EPA regulations, rather than an ongoing timeline of retrofits and retirements.

Figure 20: 2018 Summer Peak Adjusted Potential Capacity Resources (APCR) Impacts of Combined EPA Regulation Scenario



The capacity reductions identified in this scenario significantly reduce Planning Reserve Margins. The Moderate Case depicts a 4.4 percent reduction in overall capacity resulting in sizeable Planning Reserve Margin reductions for a majority of the NERC Regions/subregions. The WECC-NWPP and WECC-RMPA subregions show less than a two percentage point reduction. When considering the Deliverable Planning Reserve Margin a majority of the Regions/subregions fall below the NERC Reference Margin Level in 2018 for both cases (Figure 21). Significant capacity reductions in ERCOT, MRO, NPCC-New England, and SERC-Delta result in Planning Reserve Margin below 10 percent (see Figure 22) when considering the Adjusted Potential Planning Reserve Margin.

When considering Deliverable Capacity Resources, ERCOT, MRO, NPCC-New England, and SERC-Delta fall below zero. With Adjusted Potential Capacity Resources, the SERC-Delta Planning Reserve Margin is reduced 18.7 percentage points to -0.5 percent because of a 16 percent reduction in SERC-Delta resources.

The Strict Case shows that a 7.2 percent reduction in overall capacity results in significant Planning Reserve Margin reductions for almost all NERC Regions and subregions, except the WECC subregions of NWPP and RMPA. Planning Reserve Margins are significantly reduced as a result of capacity resource reductions greater than 10 percent in MRO, NPCC-New England, NPCC-New York, SERC-Delta, and SERC-Gateway (see Figure 22). A majority of the NERC Regions/subregions are below NERC's Reference Margin Level under the Strict Case assumptions. Most notably, MRO and SERC-Delta Planning Reserve Margin in 2018 are 3.7 and -1.7 percent, respectively. Additionally, capacity reductions in ERCOT, NPCC-New England, RFC, SERC-Gateway, SERC-Southeastern, SERC-VACAR, and SPP result in Planning Reserve Margins below10 percent.

Figure 21: 2018 Summer Peak Deliverable Capaity Resources (DCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

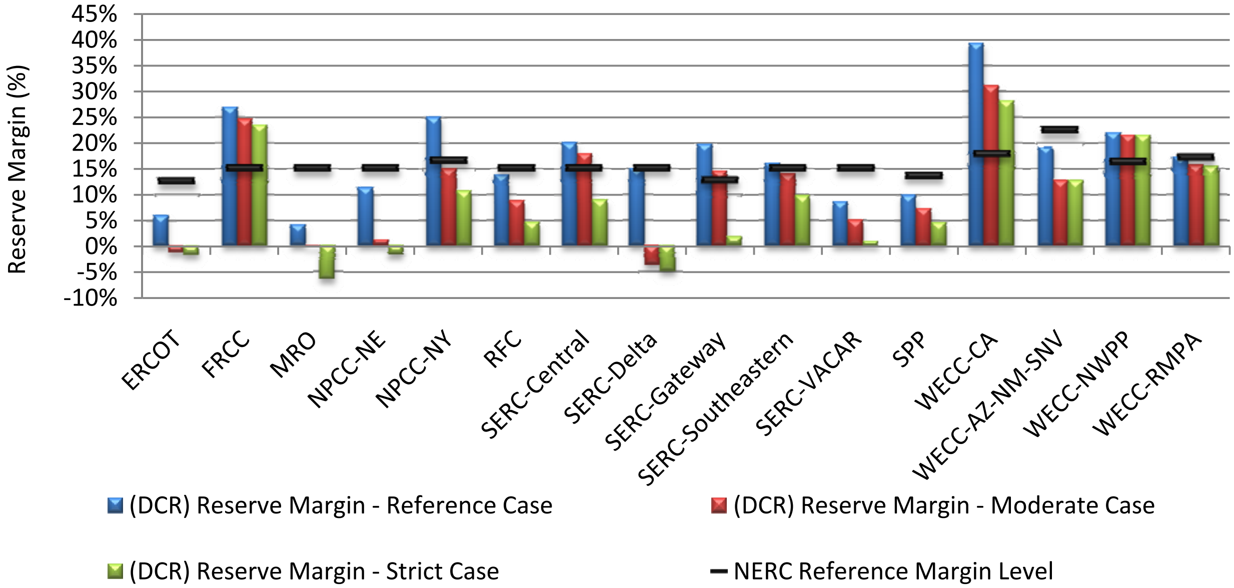


Figure 22: 2018 Summer Peak Adjusted Potential Capacity Resources (APCR) Planning Reserve Margin Impacts of Combined EPA Regulation Scenario

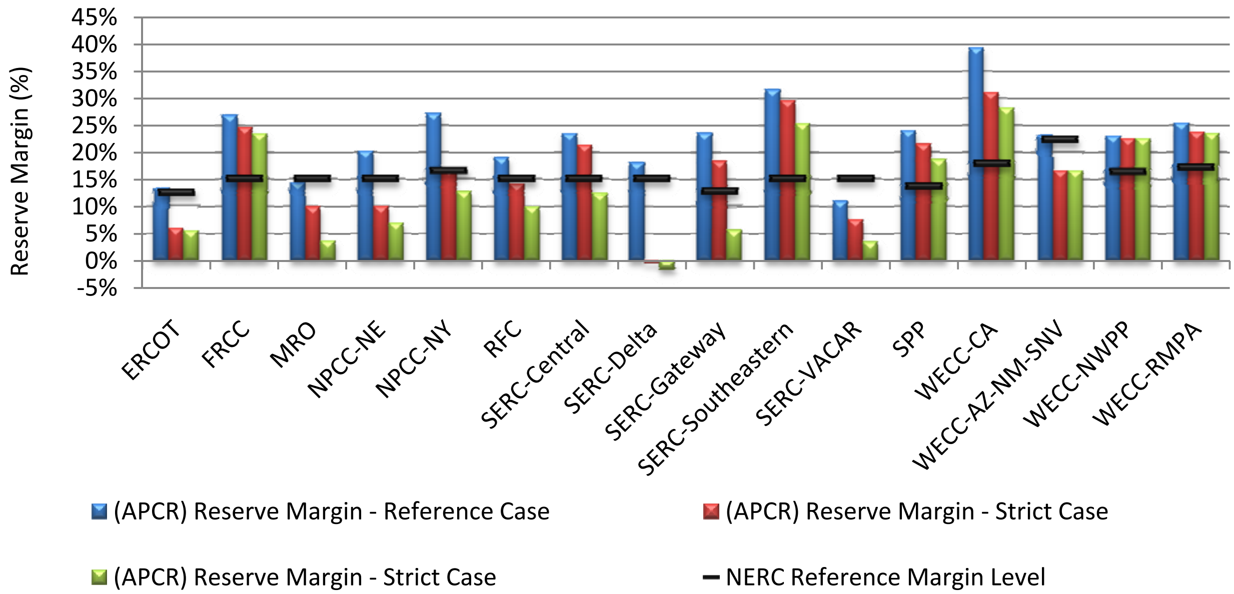


Table 14: Combined Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	-1.2% – 6.0%	-7.2 – -7.2	-1.7% – 5.6%	-7.7 – -7.7
FRCC	24.6% – 24.6%	-2.3 – -2.3	23.5% – 23.5%	-3.5 – -3.5
MRO	-0.3% – 9.9%	-4.4 – -4.4	-6.5% – 3.7%	-10.6 – -10.6
NPCC-NE	1.2% – 10.0%	-10.2 – -10.2	-1.8% – 6.9%	-13.3 – -13.3
NPCC-NY	14.9% – 16.9%	-10.2 – -10.2	10.7% – 12.7%	-14.4 – -14.4
RFC	8.7% – 14.1%	-5.1 – -5.1	4.7% – 10.0%	-9.2 – -9.2
SERC-Central	18.0% – 21.3%	-2.2 – -2.2	9.0% – 12.3%	-11.2 – -11.2
SERC-Delta	-3.7% – -0.5%	-18.7 – -18.7	-4.9% – -1.7%	-19.9 – -19.9
SERC-Gateway	14.5% – 18.4%	-5.2 – -5.2	1.7% – 5.6%	-18.0 – -18.0
SERC-Southeastern	13.9% – 29.6%	-2.1 – -2.1	9.7% – 25.4%	-6.3 – -6.3
SERC-VACAR	5.0% – 7.6%	-3.5 – -3.5	0.9% – 3.4%	-7.6 – -7.6
SPP	7.4% – 21.4%	-2.6 – -2.6	4.6% – 18.7%	-5.3 – -5.3
WECC-CA	31.1% – 31.1%	-8.3 – -8.3	28.2% – 28.2%	-11.2 – -11.2
WECC-AZ-NM-SNV	12.6% – 16.6%	-6.6 – -6.6	12.6% – 16.6%	-6.6 – -6.6
WECC-NWPP	21.5% – 22.6%	-0.5 – -0.5	21.5% – 22.6%	-0.5 – -0.5
WECC-RMPA	15.7% – 23.8%	-1.6 – -1.6	15.4% – 23.5%	-1.9 – -1.9
TOTAL	11.0% – 16.5%	-5.3 – -5.3	7.6% – 13.1%	-8.8 – -8.8

Industry Actions: Tools and Solutions for Mitigating Resource Adequacy Issue

In addition to the potential for waivers or extensions, a variety of tools and solutions can help mitigate significant reliability impacts resulting from resource adequacy concerns created by this scenario assessment. They include, but are not limited to:

Advancing In-service Dates of Future or Conceptual Resources

- Generation resources may be able to advance their in-service dates where sufficient lead time is given.
- Accelerated construction may be possible.
- Existing market tools, such as forward capacity markets and reserve sharing mechanisms, can assist in signaling resource needs. Price signalling will be important in developing new resources.

Addition of New Resources Not yet Proposed

- Smaller, combustion turbines or mobile generation units can be added to maintain local reliability where additional capacity is needed.
- Additional distributed generation may also mitigate local reliability issues.

Increased Demand-Side Management and Conservation

- Increased Energy Efficiency may offset future demand growth.
- Increasing available Demand Response resources can provide planning and operating flexibility by reducing peak demand.

Early Action to Mitigate Severe Losses

- Planning and constructing retrofits immediately will aid in preventing the potential for construction delays and overflows, mitigating the risk of additional unit loss.
- Managing retrofit timing on a unit basis will keep capacity supply by region stable..

Increase in Transfers

- Regions\subregions that have access to a larger pool of generation may be able to increase the amount of import capacity from areas with available capacity, transfer capability is sufficient. and deliverability is confirmed.
- Additional transmission or upgrades may enable additional transactions to provide additional resources across operating boundaries.

Developing or Exploring Newer Technologies

- Other technologies exist, such as trona injection, that will allow companies to comply with EPA air regulations without installing more scrubbers.

Use of More Gas-Fired Generation

- Existing gas units may have additional power production potential, which can be expanded during off peak periods. This capacity can assist in managing plant outages during the installation of emission control systems.

Repowering of Coal-Fired Generation

- Some coal-fired generation have the potential to repower their units with combined-cycle gas turbines and reducing emmisions.

The enhancements listed are all options for consideration to offset potential reliability concerns identified in this scenario assessment. The industry should closely monitor the EPA regulation process as well as continued generator participation/early-retirement announcements.

Conclusions & Recommendations

Conclusions

The results of this assessment show a significant impact to reliability should the four potential EPA rules be implemented as assumed in this assessment. Impacts to both bulk power system planning and operations may cause serious concerns unless prompt industry action is taken. Planning Reserve Margins appear to be significantly impacted, deteriorating resource adequacy in a majority of the NERC Regions/subregions. Additionally, considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort.

Of the four selected EPA rules, the Section 316(b) Cooling Water Intake Structures rule individually has the greatest potential impact on Planning Reserve Margins. Implementation of this rule will apply to 252 GW (1,201 units) of coal, oil steam, and gas steam generating units across the United States resulting in total "vulnerable" capacity of 37-41 GW by 2018. Additionally, approximately 60GW of nuclear capacity may be affected. Because of this scenario, Planning Reserve Margins are decreased as much as 18 percentage points in the SERC-Delta subregion where the margin falls below zero (available generation will be unable to serve load), unless additional resources are added. Other Regions/subregions affected include NPCC-New England and New York.

The remaining three selected EPA rules assessed will mostly affect existing coal-fired capacity, ranked in descending order:

MACT

- The EPA MACT Rule alone could trigger the retirement of 2-15 GW (Moderate Case and Strict Case) of existing coal capacity by 2015. The "hard stop" 2015 compliance deadline proposed by the EPA MACT Rule makes retrofit timing a significant issue and potentially problematic.

CATR

- The CATR also could have significant impacts as soon as 2015, should EPA require emission limits with no offset trading, resulting in potentially 3-7 GW of retired and derated capacity and require retrofitting of 28-576 plants with environmental controls by 2015.

CCR

- The CCR Rule alone is projected to have the least impact, triggering the retirement of up to 12 coal units (388 MW). While the resulting impacts of the CCR scenario may not have significant impacts to capacity by itself, the associated compliance costs of CCR contribute to the Combined EPA Regulation Scenario.

Based on the assessment's assumptions, the greatest risk to Planning Reserve Margins occurs in 2015 for the Combined EPA Regulation Scenario. The overall total impact could make 46-76 GW of existing capacity "economically vulnerable" for retirement or derating by 2015. Additionally, the scenario cases assessed in this report indicate capacity reductions evident as early as 2013, resulting from the retirements of coal-fired plants and derate effects associated with plant retrofits. Impacts to Planning Reserve Margins can occur during the next four to eight years that could reduce bulk power system reliability, unless additional resources are constructed or acquired. It is essential that projected Conceptual supply resources be developed as one source of capacity replacement.

Recommendations

In the future, a variety of demands on existing infrastructure will be made to support the evolution from the current fuel mix, to one that includes generation that can meet proposed EPA regulations. The pace and aggressiveness of these environmental regulations should be adjusted to reflect and consider the overall risk to the bulk power system. EPA, FERC, DOE and state utility regulators, both together and separately, should employ the array of tools at their disposal to moderate reliability impacts, including, among other things, granting required extensions to install emission controls.

Industry participants should employ available tools to ensure Planning Reserve Margins are maintained while forthcoming EPA regulations are implemented. For example, regional wholesale competitive markets should ensure forward capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in regulated markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations.

NERC should further assess the implications of the EPA regulations as greater certainty or finalization emerges around industry obligations, technologies, timelines, and targets. Strategies should be communicated throughout the industry to maintain the reliability of the bulk power system. This assessment should include impacts to operating reliability and second tier impacts (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) of forthcoming EPA regulations.

Appendix I: Assessment Methods

Method for This Assessment

Some studies completed by various organizations have made assumptions that environmental regulations will cause all units that meet a certain criteria to retire, for example, all units less than 230MW that have a capacity factor below 35 percent. This simplified approach does not consider other important factors:

1. Regulated versus deregulated plant (can affect the ability to finance capital improvements as well as the cost of capital)
2. Unit ownership that can affect the cost of capital
3. Regional reserve margin, *i.e.*, the need to build new capacity to replace retired capacity
4. Operating cost of the unit versus the operating cost of replacement capacity
5. Management's attitude toward fossil fuel generation
6. State specific implementation
7. Other local and unit specific issues

In developing this report, NERC used a contracted model from Energy Ventures Associates (EVA), which does not consider Reference Planning Reserve Margins commitments, reliability-must-run factors or transmission constraints. Instead, the model applied generic costs factors, related to unit size and unit location, to each unit. An economic approach is used to identify units to retire when the generic required cost of compliance with the proposed environmental regulation exceeds the cost of replacement power. For the purpose of this assessment, replacement power was considered to be gas-fired capacity. This assessment was completed in constant 2010 U.S. dollars.

EVA used its delivered natural gas and coal price forecasts. All gas prices were assessed at the point of delivery to the electric generation plant. In addition, coal supply costs were adjusted for any savings resulting from the ability to burn a different quality of coal, *e.g.*, higher BTU coal.

One deviation from this general method occurs specifically for the expected outcome of the CATR regulation, such that the model considers the surplus credits that have accumulated and allows them to be used as an offset in lieu of installing additional environmental controls.

A brief description of the method follows:

Retirement criteria: retire if (CC+FC+VC) / (1-DR) > RC, where:

CC = required compliance cost in $/MWH
FC = current fixed O&M in $/MWH
VC = variable O&M including fuel cost in $/MWH
RC = replacement cost in $/MWH
DR = derate factor that accounts for the incremental energy loss due to any new environmental controls

Appendix I: Assessment Methods

CC = function(incremental capital, incremental fixed O&M cost, incremental variable O&M, cost of capital, capacity factor, remaining life without new regulation)

(IC * CRF +IFOM) / (8.76*CF) + IVOM, where:

IC = Incremental capital cost ($/kW) that is plant specific for each regulation, *i.e.*, can range from zero if the plant is already in compliance to the cost of any additional capital to comply with the proposed regulation. This cost is a function of the size of the plant and its location.

CRF = Capital recovery factor = $i * (1 + i)^n / ((1 + i)^n - 1)$

i = Pre-tax cost of capital:
Deregulated IOU = 17.5%
Regulated IOU = 12.7%
Coop = 7%
Municipality = 6%

n = Remaining life in years, linear interpolation between [CF=0, n=3], and [CF=100%, n=30], *i.e.*, if CF=30% then
n = (1-30%)*3 + 30%*30 = 11.1 years

IFOM = Incremental increase in the fixed O&M cost ($/kW-yr)

CF = Capacity factor of the plant in 2008

IVOM = Incremental increase in the variable O&M cost ($/MWh)

FC = Current fixed O&M cost in $/kW-yr / (8.76*CF)[34]

	0 MW	100MW	>300 MW
Coal =	$30.00/kW-yr	$21.00/kW-yr	$18.00/kW-yr
O/G Steam =	$22.50/kW-yr	$15.75/kW-yr	$13.50/kW-yr

VC = Variable O&M cost in $/MWH

	0 MW	100MW	>300 MW
Coal =	$5.00/MWh	$4.00/MWh	$3.75/MWh
O/G Steam =	$3.33/MWh	$2.67/MWh	$2.50/MWh

Plus fuel cost
= Delivered fuel cost ($/MMBtu) * heat rate (1000 Btu/kWh)

[34] Fixed Brownfield construction costs may be lower than the Greenfield costs assumed in this assessment.

RC = Replacement cost is a function of the capacity factor, cost of new combined cycle plants, cost of new peaking capacity, and natural gas price

If CF between 10% and 90%,
RC = [(1 - (CF - 10%)/80%) * RC10 + (CF- 10%)/80% * RC90]
If CF <=10%, RC = RC10
If CF >=90%, RC = RC90

RC10 = Full capital and operating cost of a new GT unit in the NERC Region in $/MWh@ 10% CF with the capital and delivered natural gas cost varying by region

RC90 = Full capital and operating cost of a new CC unit in the NERC Region in $/MWh@ 90% CF with the capital and delivered natural gas cost varying by region

A capacity factor of 90 percent was selected for the combined cycle unit as a proxy for the practical, maximum, annual operating rate of a typical fossil fuel unit. A capacity factor of 10 percent was selected for peaking gas plants as the upper limit of what is typically observed under actual operating conditions.

New gas plant cost assumptions illustrated by Table I-1 are:

Table I-1: Model Assumptions - New Gas Plant

	Average Ten Year Outlook for NG Price				New Combined Cycle Plant			New Gas Turbine			Other Parameters	
	Combined Cycle Natural Gas Price in $/MMBtu		Gas Turbine Natural Gas Price in $/MMBtu									
	2013-2022	2018-2027	2013-202	2018-202	Capital $/kW	Fixed O&M $/kW-yr	Var O&M $/kWH	Capital $/kW	Fixed O&M $/kW-yr	Var O&M $/kWH	Pre-Tax WACC	CRF $30.00
ERCOT	$6.35	$6.94	$6.26	$6.84	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
FRCC	$7.75	$8.36	$6.78	$7.36	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
MRO	$6.40	$6.98	$6.30	$6.88	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
NPSS-NE	$7.10	$7.69	$6.99	$7.57	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
NPCC-NY	$6.79	$7.34	$6.68	$7.22	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
RFC	$6.68	$7.25	$6.39	$6.94	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
SERC-Central	$6.46	$7.02	$6.29	$6.85	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-Delta	$6.27	$6.85	$6.18	$6.75	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-Gateway	$6.34	$6.96	$6.11	$6.73	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-Southeastern	$6.65	$7.21	$6.48	$7.04	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SERC-VACAR	$6.86	$7.42	$6.59	$7.14	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
SPP	$6.76	$7.32	$6.54	$7.09	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130
WECC-AZ-NM-SNV	$6.23	$6.80	$6.08	$6.64	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
WECC-CA	$6.46	$7.06	$6.31	$6.89	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
WECC-NWPP	$6.35	$6.94	$6.20	$6.77	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	19.1%	0.192
WECC-RMPA	$5.99	$6.54	$5.84	$6.38	$1,200.00	$19.50	$6.00	$600.00	$7.50	$4.00	12.7%	0.130

*** Constant 2010 NG Price**

WACC = Weighted Average Cost of Capital

CRF = Capital Recovery Factor

Heat Rates: 7,000 for combined cycle and 10,000 for gas turbine

Appendix II: Potential Environmental Regulations

Section 316(b) Cooling Water Intake Structures

The typical power plant uses a fuel (coal, gas or nuclear) to heat water into steam, which then turns a turbine connected to a generator, which produces electricity. The steam then condenses back into water to continue the process again. This condensation requires cooling either by water, air, or both. In open-loop cooling, (see Figure II-1), large volumes of water withdrawn from a water source (reservoir, lake or river) pass through the heat exchanger to condense steam in a single pass before the majority returns to the source. Closed-loop cooling is an alternative to open-loop cooling (see Figure II-2). Closed-loop cooling systems circulate a similar total volume of water as open-loop systems for a given plant size, but only withdraw a limited amount of water to replace evaporative loss and blow-down. There is also “dry” or air-cooling which requires little to no water and is cooled directly or indirectly via conductive heat transfer using a high flow rate of ambient air blown by fans across the condenser.

Figure II-1: Open-Loop Cooling

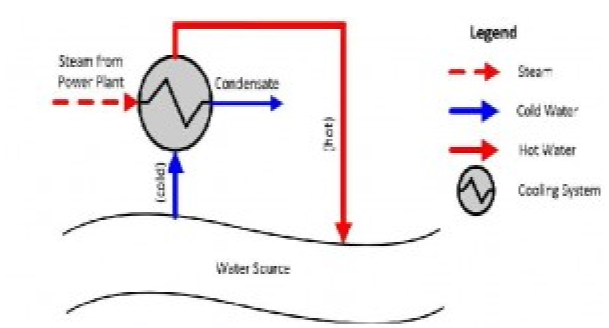
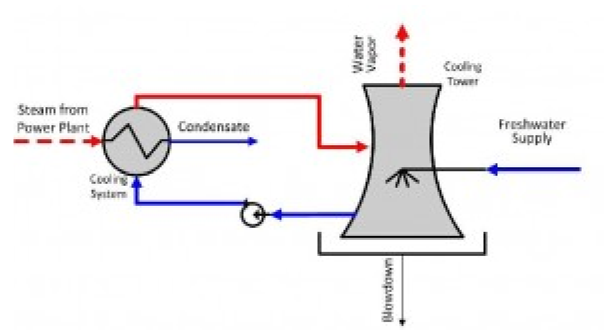


Figure II-2: Closed-Loop Cooling



Section 316(b) of the Clean Water Act regulates cooling water intake structures and requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. In defining BTA, EPA has, for more than 30 years, considered the cost and benefits of control alternatives. EPA originally developed the Section 316(b) rule for existing generation facilities using greater than 50 million gallons per day (mgd) in 2004-2007. However, parts of the rule were overturned in the U.S. Court of Appeals in 2007 and remanded to EPA for reconsideration. EPA is planning to issue a new draft rule for public comment by September 2010. Rule implementation is likely to start during 2014 and be fully implemented over a five-year compliance period.

This proposed water rule will likely apply to all existing and new nuclear and fossil steam generating units, which contributed over 93 percent of 2008 U.S. generation. Power sources such as combustion turbines, hydroelectric facilities, wind turbines, and solar PV panels use no cooling water and therefore will not be subject to the proposed rule. Major EPA proposed making policy issues directly affecting Planning Reserve Margins are:

- implementation period;
- applicability to existing structures and; and
- EPA BTA retrofit technology selection.

In its original 2004 existing facilities rule (overturned by the U.S. Court of Appeals in 2007), EPA set significant new national technology-based performance standards. The standards are intended to minimize adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost. The performance standards prescribed ranges of reductions based on several factors and provided multiple compliance alternatives including the use of economic tests to properly implement site-specific regulatory BTA determinations.

However, EPA's expected draft replacement rule (Phase II) is expected to be substantially different due in part to the fact that the performance standards are expected to favor performance commensurate with cooling towers. In addition, despite a 2009 Supreme Court ruling that EPA has the discretion to use cost-benefit analyses when setting performance standards, EPA has signaled concerns associated with the use of cost-benefit analyses.

For example, if EPA defines BTA for cooling water systems such as recirculating cooling water systems with a reach-back provision to cover existing cooling water systems, up to 312 GW of existing steam electric power stations that use once-through cooling water systems may require additions to retrofit recirculating cooling water systems or acceleration of their retirement. For those units opting to retrofit, the stations would increase onsite electricity consumption (1-4 percent) from station loads because of increased power needs for cooling water pumping.

In its October 2008 report titled *Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generating Units*, the U.S. Department of Energy (DOE) estimated that a tougher mandatory recirculating cooling water requirement, now being considered by EPA, would accelerate the retirement of 39.6 GW of existing fossil capacity and derate retrofitted control units by an additional 9.3 GW.[35] The DOE study made a simplifying assumption that existing steam units with once through cooling water systems operating at capacity factors less than 35 percent would be retired and retrofitted plant output capacity was reduced by four percent to represent increased station loads.

The 1,200 affected units with once through cooling water systems and their cooling water intake power suppliers identified rates through the U.S. Energy Information Administration (EIA) Form 923 and older Form 767 (Steam Electric Plant Operation and Design Report) data filings.[36] The affected units include 754 coal units, 405 oil/gas steam units and 42 units of nuclear capacity.

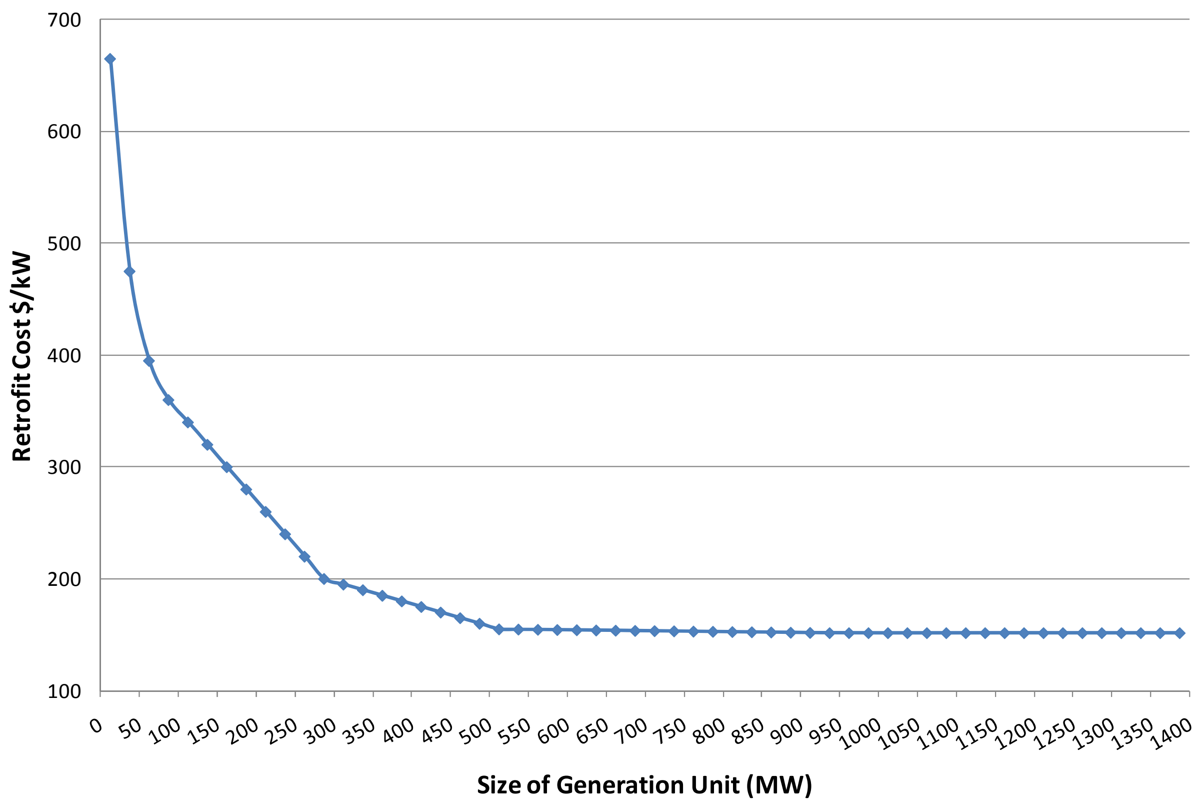
[35] http://www.oe.energy.gov/DocumentsandMedia/Cooling_Tower_Report.pdf
[36] http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html

For these units, capital cost estimates to convert from once through cooling water to recirculating cooling water systems are derived from three engineering studies and cost surveys:

- EPRI: *Issues Analysis of Retrofitting Once Through Cooled Plants with Closed Cycle Cooling* (10/07);[37]
- Maulbetsch Consulting: EPRI Survey of 50 plant estimates (7/2002); and
- Stone & Webster: Study for Utility Water Assessment Group (7/2002).

These studies found that capital conversion costs are directly tied to the once-through cooling water pumping rate and heavily influenced by site layout and local conditions. Conversion costs ranged from \$170-440 (2010 dollars) / gallons per minute (gpm) with an average capital conversion cost of \$240/gpm. The average conversion costs were applied for most locations, except for known urban locations having constrained site conditions for which a 25 percent higher capital cost estimate of \$300/gpm (2010 dollars) was applied. The base case costs applied in this reliability assessment are shown in Figure II-3.

Figure II-3: Base Case Retrofit Cost Curve for Section 316(b)($/kW)



In addition to the capital conversion costs, the station would lose both capacity and energy due to increased power consumption from the cooling water pump. The capacity and energy losses estimated in the 2008 DOE study and applied in this assessment are shown in Table II-1.

[37] EPRI is expected to issue a new revised report that will include detailed cost information not only for installing cooling towers, but also for retrofitting plants on sensitive water bodies, and operations and maintenance costs.

Table II-1: Capacity Derating/Energy Penalties Due to Cooling Tower Conversion

NERC Regions/ Subregions	Average Energy Loss %	Capacity Derating Penalty (%)
ERCOT	0.80%	2.50%
FRCC	0.90%	2.50%
MRO	1.40%	3.10%
NPCC	1.30%	3.40%
NYPP	1.20%	3.20%
RFC	1.60%	3.40%
Entergy	0.90%	2.60%
Gateway	1.20%	3.10%
Southeastern	0.80%	2.40%
TVA	0.90%	2.60%
VACAR	1.00%	2.80%
SPP	1.00%	2.80%
AZ-NM-SNV	1.40%	2.70%
CA	0.90%	2.50%
NWPP	1.40%	3.00%
RMPA	0.00%	2.50%
Total	1.20%	2.90%

Source: DOE *Electric Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generating Units*(10/2008)

However, these referenced compliance costs and reliability impacts may be underestimated for the following reasons:

- First, the published studies used to develop the average capital cost estimates are based upon surveys done in 2002 and 2007. Such conversions are rare; no historic costing data have been published. Since these surveys, environmental project construction costs have escalated rapidly.
- Second, the site-specific conditions and plant layout can have significant impacts on conversion costs that are not reflected by applying industrial average estimates. Although an adjustment was made for known constrained urban sites, several more sites likely exist that may have similar (but unknown) site constraint problems.
- Finally, given the short potential rule implementation period and the large affected power plant population, demand for labor and construction materials for conversions could be in high demand and result in real cost escalation. Such capital cost run-ups have occurred in pollution control projects.

The Strict Case provides a 25 percent real price escalation in the average conversion cost to \$300/gpm at most locations and \$400/gpm at known constrained urban site locations to capture these potential risks. Alternatively, EPA could consider several policy options that could reduce the rule's impact. These options include (1) narrowing the rule scope to the largest cooling water consumers (*e.g.*, EPA's original rule applied only to water intakes greater than 50 million gallons per day), and (2) applying lower cost technology options for existing cooling systems (*e.g.* retrofitting fine mesh screens per the 2004 rule). Any narrowing of the regulation scope or cost would reduce the rule's reliability impacts. These alternative EPA regulatory options were not modeled for this assessment.

Appendix II: Potential Environmental Regulations

National Emissions Standards for Hazardous Pollutants (NESHAP) or Maximum Achievable Control Technology (MACT)

Under Title I of the 1990 Clean Air Act, EPA is obligated to develop an emission control program for listed air toxics for sources that emit at or above prescribed threshold values, including mercury. The Clean Air Act defines MACT for existing sources as "the average emission limitation achieved by the best performing 12 percent of the existing sources." EPA is obligated under a consent decree to propose a MACT rule by March 16, 2011 and to finalize the rule by November 16, 2011. The Clean Air Act mandates a three-year compliance timeframe: 2014 or 2015.

The potential EPA MACT rule will apply to all 1,732 existing and future coal and oil fired capacity (415.2 GW of existing plus another 26 GW of new planned coal units). The only flexibility for compliance is for EPA to grant a one-year extension, granted on a case-by-case basis, and a Presidential exemption of no more than 2 years based on availability of technology and national security interests.

This assessment uses environmental control costing curves to develop unit-specific compliance cost estimates, with the increased unit production costs of new pollution controls compared to unit production costs of replacement power. EPA is expected to adopt different MACT emission rate limitations, which implies that new investments required will vary by coal type.

The Moderate Case assumes that MACT is not fully implemented until 2018, as waivers are provided, largely for reliability reasons, to units that have committed and scheduled environmental upgrade projects but which may not be completed by the 2015 deadline. Further, investments are made when equipment is not present or planned, depending on the coal type, as shown in Table II-2. If wet or dry FGD are not present, then wet FGD is added for all coal types. SCR control retrofits are added for bituminous coal only. In addition, fabric filter systems with halide-treated activated carbon injection (HACI) systems are added for all coal types, if not already present. Oil stations (109.7 GW) are assumed to meet their air toxic limits through tighter oil specifications at the refinery.

By contrast, Strict Case assumes no waivers are granted and all upgrades must be complete by January 1, 2015, or units would retire. Investment costs are also projected to increase by 25 percent in Strict Case as shown by Table II-3.

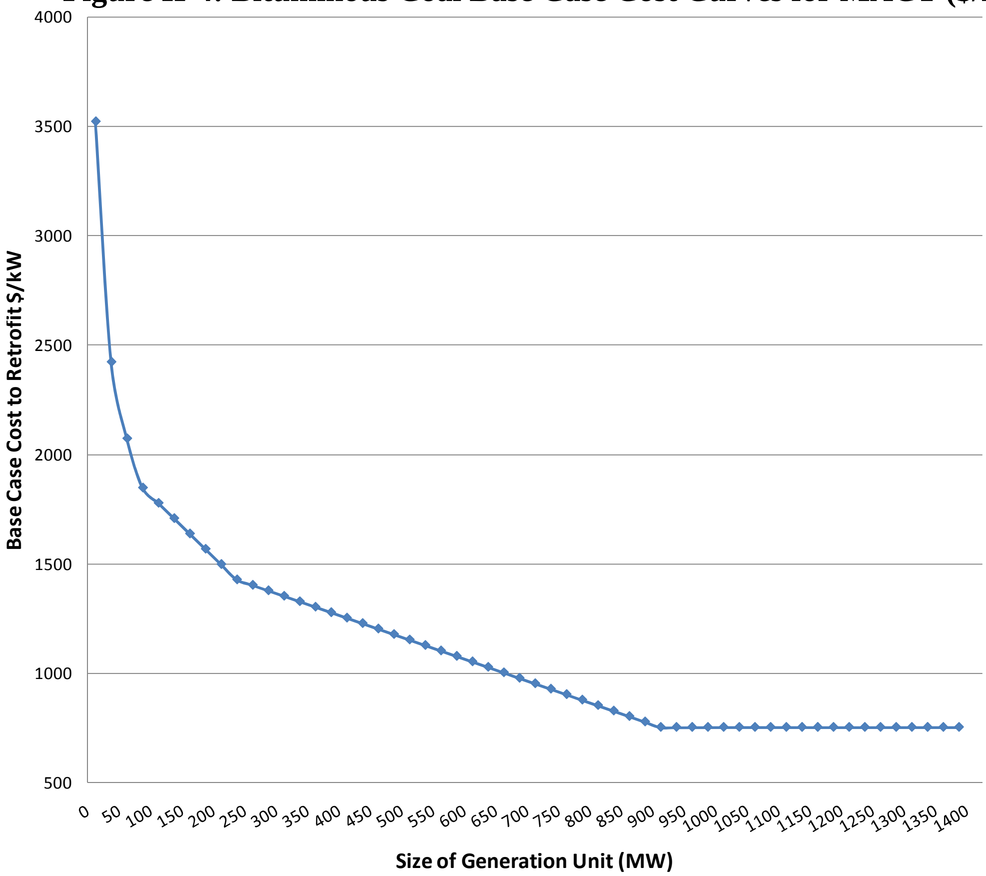
Table II-2: Moderate Case Assumptions for MACT Air Toxics (includes CAMR and Acid Gases)

	Moderate Case		
	Bituminous	Sub-bituminous	Lignite
Wet FGD	If no wet or dry FGD, add wet FGD	If no wet or dry FGD, add wet FGD	If no wet or dry FGD, add wet FGD
Dry FGD			
SCR	Add		
Activated Carbon Injection		Add	Add
Baghouse (Fabric Filter)		Add	Add

Table II-3: Strict Case Assumptions for MACT Air Toxics (includes CAMR and Acid Gases)			
	Bituminous	Sub-bituminous	Lignite
Wet FGD	25%	25%	25%
Dry FGD	25%	25%	25%
SCR	25%		
Activated Carbon Injection	+25% Add	25%	25%
Baghouse (Fabric Filter)	+25% Add	25%	25%

Representative base case costs for bituminous coal are shown in Figure II-4.

Figure II-4: Bituminous Coal Base Case Cost Curves for MACT ($/kW)

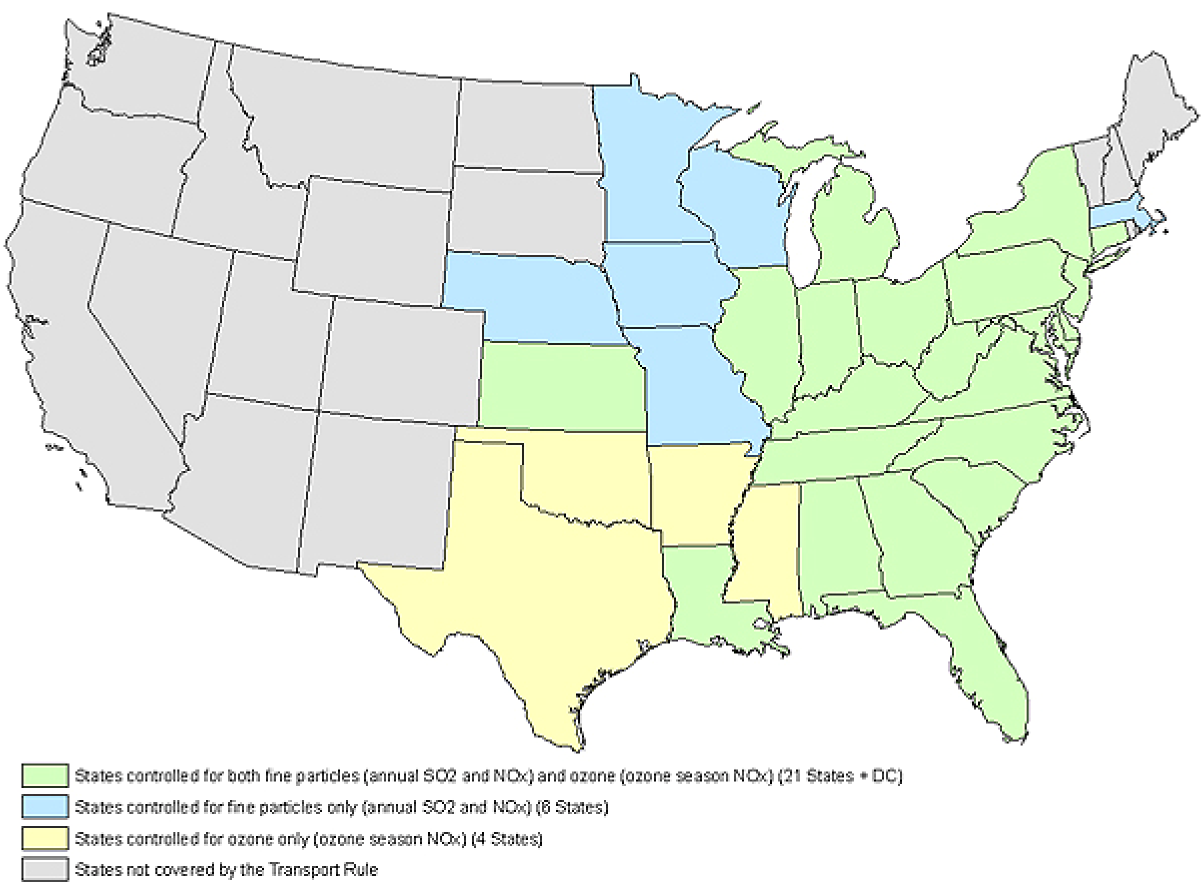


Clean Air Transport Rule (CATR)

EPA developed its Clean Air Interstate Rule (CAIR) program to address the long-range emission transport contribution to fine particulate non-attainment and to take the first compliance step by reducing contributions from major fossil combustion stationary sources. Its *original* proposed program created a new annual NO_x cap-and-trade program and modified the existing Title IV SO_2 cap-and-trade program for 28 states for which upwind out-of-state contributions to non-attainment areas were considered significant. In 2008, the U.S. Court of Appeals overturned the EPA program due to concerns that NAAQS would not be met if sources complied through an unlimited amount of emission allowance purchases.

In July 2010, EPA proposed a draft CATR to control long-range transport of power plant SO_2/NO_x emissions that significantly contributed to non-attainment of fine particulate and ozone ambient air quality standards in downwind states—CATR will replace CAIR.[38] EPA anticipates issuing the final rule by March 2011. The draft program would apply only to fossil fuel electric generating units greater than 25 MW located in a designated state as shown in Figure II-5 .

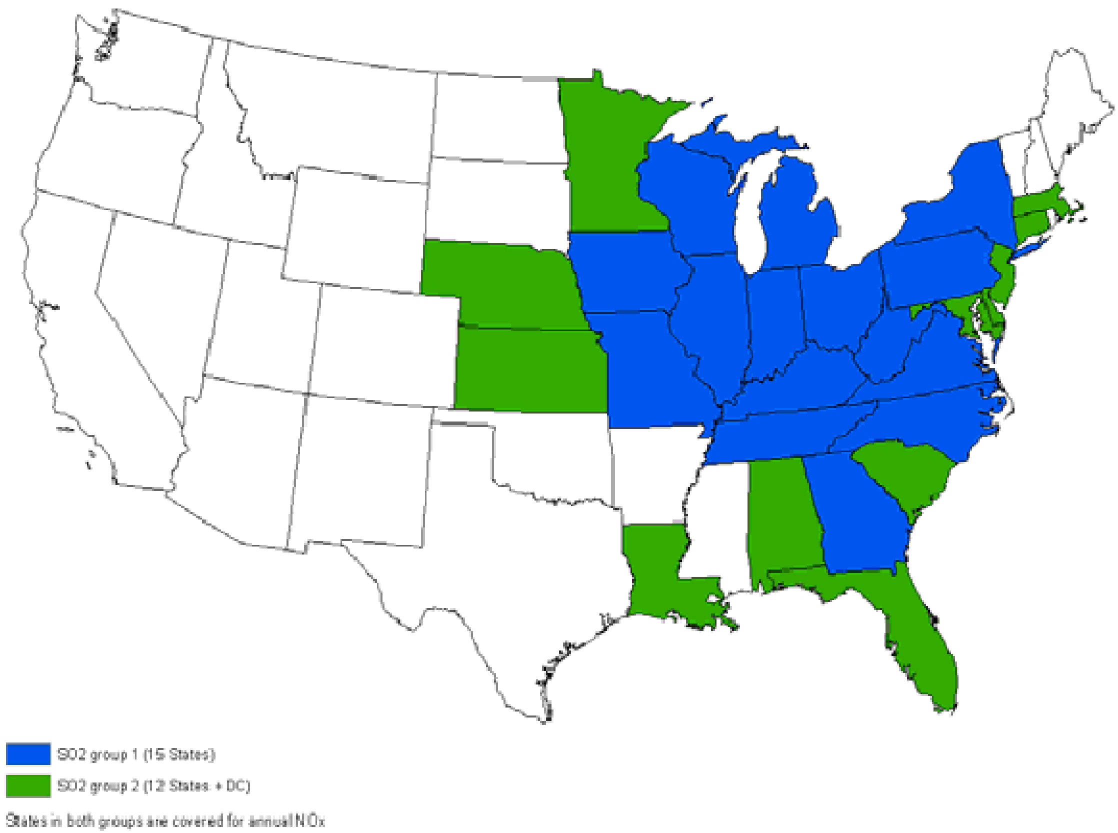
Figure II-5: Clean Air Transport Rule Designated States



[38] EPA CATR Homepage: http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1 and proposed rule http://www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1

The potential EPA rule will regulate SO_2 and NO_x emissions under three new cap-and-trade programs (SO_2, annual NO_x and seasonal NO_x) starting January 1, 2012. EPA will set a state emissions budget cap for each pollutant, issue new allowances, and propose to significantly limit interstate allowance trading and banking after 2013. Previously banked surplus SO_2 and NO_x allowance credits and allocations created under the Acid Rain and CAIR programs cannot be used for compliance under the new program. For SO_2, affected states are organized into Group 1 or Group 2, as shown in Figure II-6.

Figure II-6: Clean Air Transport Rule Designated States



CATR applies to fossil power plant sources located within the 31 states and District of Colombia. The impact on the electric grid will vary depending on which of three EPA proposals becomes the final rule[39]:

- The EPA preferred option;
- Alternative 1 - the no interstate trading option; or
- Alternative 2 - the strict emission rate option.

EPA proposal is soliciting comments on its preferred option with limited interstate trading and intrastate trading, as well as the two alternative options. Further complicating compliance planning by electric generators, the agency recognizes that the proposed state emission budgets

[39] Described in the *Introduction* section of this report

caps are likely to change again in the near term when new fine particulate and ozone air quality standards are adopted, potentially later in 2010. These NAAQS will trigger new air quality modeling to determine the allowable pollutant loadings and allocations between contributing sources. Upon completion of this modeling, EPA will propose new state emission budget caps. The rule also gives the power industry a greater planning challenge than CAIR, since compliance must be on an aggregate state-by-state basis. In lieu of the current national emissions cap with unrestricted trading and banking, the new proposal also makes greater coordination essential between utilities within each state in order to optimize emission reductions. However, concerns over competition may limit coordination and result in less optimal compliance plans.

The new program is likely to require some electric generation units to retrofit additional FGD and selective catalytic reduction (SCR) controls by 2014, or retire. Strict emission limits that can only be met with post combustion FGD and SCR controls will directly affect 163 GW of coal-fired capacity that currently does not have FGD, or the 180 GW without post combustion NO_x controls. EPA's preferred option is summarized in Table II-4 below.

Table II-4: High Level Summary of Proposed CATR Regulation – EPA Preferred Option

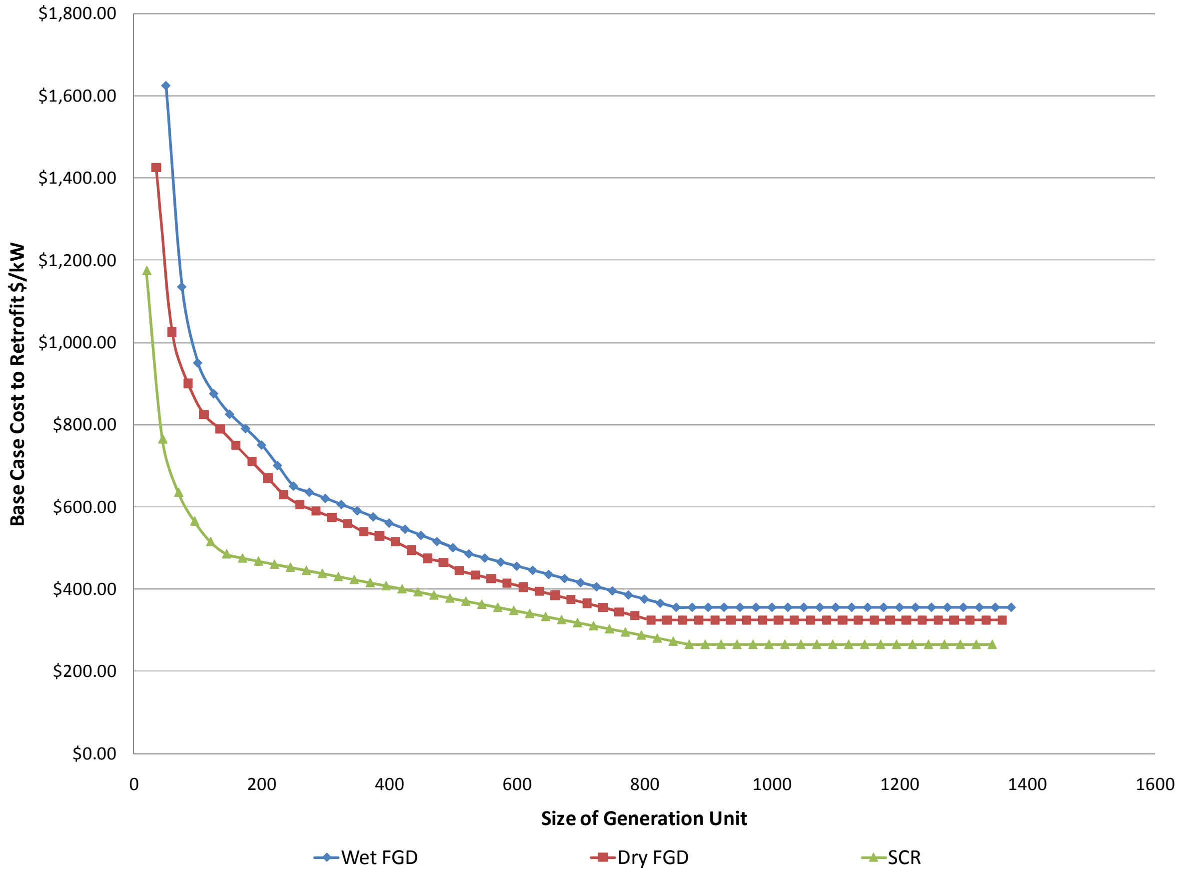
SO_2 Cap & Trade Program				
	Group 1		Group 2	
	2012 Deadline	2014 Deadline	2012 Deadline	2014 Deadline
Number of States Affected	15	15	12 & DC	12 & DC
Emissions Cap (TPY)*	3,117,288	1,723,412	776,582	776,582
Emissions Credit Trading	EPA issues new allowances and surplus acid rain allowances become worthless. Trading allowed within Group 1.	Very strict annual state emission limitations on interstate trading and use of carryover allowances.	EPA issues new allowances and surplus acid rain allowances become worthless. Trading allowed within Group 2.	Very strict annual state emission limitations on interstate trading and use of carryover allowances.

**EPA resets each state's budget at onset. State budget caps are likely to be revised once fine particulate NAAQS is implemented and modeling* is completed.

Annual NO_x Cap & Trade Program		
	27 States and District of Colombia	
	2012 Deadline	2014 Deadline
Number of States Affected	28	28
Emissions Cap (TPY)	1,317,312	1,317,312
Emissions Credit Trading	EPA issues new allowances and surplus CAIR ones become worthless. Trading allowed between all states.	Very strict annual state emission limitations on interstate trading and use of carryover allowances.

The costs for retrofitting post combustion controls are shown in Figure II-7. These capital costs are from utility project engineering estimates and recent projects. They are significantly higher than EPA study estimates that rely upon much older cost data and exclude owner and financing costs.

Figure II-7: Moderate Case Average Post Combustion Control Retrofit Costs for CATR ($/kW)



This assessment examines the impacts of the EPA's preferred option – limited cap-and-trade program -- as the Moderate Case. This option increases pressure to reduce emissions beyond current plans, particularly for sources in the six states of Indiana, Kentucky, Massachusetts, Missouri, Ohio and Pennsylvania. These six states must reduce their aggregated in-state SO_2 emissions by more than 250,000 tons per year by 2014. It may prove difficult to engineer, finance, permit and construct sufficient environmental controls in less than the three years required under the draft program. This assessment examines the economic decision at current control prices. The Strict Case assumes that EPA elects to adopt their future emission rate alternative that has no provisions for any trading between units and will force more coal units to have post combustion SO_2 and NO_x controls in the selected states. The assessment evaluates the available state credits to meet the state's limits and selects generating units for retirement in 2012 and 2014 that will be required to meet the emissions cap.

Appendix II: Potential Environmental Regulations

Coal Combustion Residuals (CCR)

Concerns raised by the December 2008 Kingston ash spill and its widespread environmental impact triggered EPA consideration of changing regulating coal-ash and waste byproduct (*e.g.*, scrubber sludge) disposal from its current special waste designation to Subtitle C Hazardous Waste under the Resource Conservation and Recovery Act. EPA developed a draft rule in September 2009 that was reviewed by the Office of Management and Budget and was issued in May 2010. A final rule is expected in 2011, with implementation expected to start in 2013–2015 and full compliance by 2018.

These EPA rules will regulate 136 million tons per year (tpy) of coal-ash and solid byproducts currently produced by the coal-fired stations. Policy issues that will impact decision making the most include:

- hazardous waste designation of coal-ash,
- impoundment design standards,
- groundwater protection standards, and
- rule implementation period.

EPA has proposed conversion of all coal-ash handling systems from utility-boilers to dry based systems, with two options proposed for disposal of all ash and coal byproducts in a landfill meeting either Subtitle C or D, which entails different types of waste disposal standards, and to close/cap existing ash ponds. Such a ruling requires the 359 coal units (128.5 GW) to convert their wet ash handling systems to dry based systems, incur greater ash disposal costs for the 136 million tons of ash disposal each year, and close and cap the existing 500 ash/sludge ponds in operation.

In addition, a hazardous waste designation under Subtitle C could eliminate the market for 20 million tons of ash that is currently resold into the market, although the EPA is considering a "special waste" designation, which would allow "beneficial" reuse of the substance to continue. Hazardous waste designation without exceptions would vastly expand the existing hazardous waste disposal market from its current size of 2 million tpy.

Prior public studies examining the ash disposal issue on power plant operation are limited. A 2009 EOP Group Study titled *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal fired Utilities* was reviewed.[40],[41] This 2009 study concluded that EPA's draft rule could directly affect operations at 397 coal generating units (175 GW). The EOP Group study estimated bottom ash conversion costs of $30 million per unit, and this assumption is used in the Moderate Case of this assessment. In addition, at some stations, the ash ponds also dispose of fly ash (15 million tons per year or tpy) that would require an additional $3 billion investment to convert to dry handling systems. Outside of conversion costs, stations would have to build alternative wastewater treatment facilities at 155 facilities ranging, per facility, from $80 million without a flue gas desulfurization system (FGD) to $120 million with FGD per facility to provide storm water and/or FGD scrubber sludge treatment currently handled by the ash ponds. Ash pond closure

[40] http://www.whitehouse.gov//sites/default/files/omb/assets/oira_2050/2050_102809-2.pdf

[41] A revised EOP report is currently under review, reference report upon completion. Preliminary values indicate a 20 percent increase in cost.

costs were estimated to be $30 million per pond. The EOP Group study concluded, "*Units with below 230 MW of generating capacity have the greatest potential risk of ceasing operations if required to undertake mandatory closure of CCB surface impoundments*." These "economically vulnerable" coal units totaled 35 GW of existing capacity and represented 18 percent of 2005 U.S. coal generation.

However, the 2009 EOP Study contained some deficiencies that could underestimate compliance costs as follows:

- First, the study excluded any land acquisition costs for landfill or expanded wastewater treatment facilities.
- Second, the study excluded the increased disposal cost if ash was designated as hazardous waste.
- Third, it excluded costs for existing ash pond closures. These remediation costs will vary significantly based upon the extent of any groundwater contamination, site geology and aquifer use. However, any remediation might be considered as a sunk cost since it would be incurred independently of the future operating decision. If these costs were indeed considered sunk, they should not be incorporated into unit retirement decisions.

A total of 359 coal-fired units (128.5 GW) of coal-fired capacity reported using wet pond based systems for their ash and/or byproduct handling systems in their EIA Form 767 and 923 filings. For these units, the 2009 EOP study cost estimates for bottom ash conversion and wastewater treatment upgrades are applied on a unit basis. The additional EOP ash waste disposal costs of $15 per ton (2010 dollars) were added for handling in a regulated non-hazardous onsite landfill to the unit operating costs in the Moderate Case of this study. The pond closure and remediation costs are assumed to become sunk costs that would be incurred independently of the future power plant operations. Therefore, only incremental costs associated with ongoing operations are accounted for in the decision to invest or retire the unit. When these incremental power production costs exceeded new replacement capacity costs, the units became potential retirement candidates.

However, as outlined above, the EOP Group study may have underestimated compliance costs and thereby underestimated potential grid reliability impacts. Based on discussions with various subject-matter experts, the capital compliance cost uncertainty is likely to be plus/minus 25 percent. To account for potentially higher costs under stricter Subtitle C guidelines, landfill costs are assumed to be much higher at $37.50 per ton (2010 dollars) in the Strict Case, which is also similar to the EPA study's estimated disposal costs. In lieu of conducting site-specific assessments, sensitivity comparisons are completed across a wide range of ash disposal costs from $37.50 to $1,250 per ton.

Appendix III: Capacity Assessed by NERC Subregion

Figure III-1: Base Fossil-Fired Generation Capacity Assessed by NERC Region/Subregion

	No. Units	Capcity (MW)
Coal Units		
ERCOT	31	17,685
FRCC	22	9,444
MRO	157	25,231
NPCC-NE	13	2,634
NPCC-NY	21	2,812
RFC	309	97,302
SERC-Central	99	24,487
SERC-Delta	21	9,317
SERC-Gateway	51	13,998
SERC-Southeastern	65	24,223
SERC-VACAR	109	24,147
SPP	62	19,111
WECC-CA	10	2,182
WECC-AZ-NM-SNV	29	11,911
WECC-NWPP	39	12,097
WECC-RMPA	45	6,419
TOTAL	1080	302,998
O/G - ST Units		
ERCOT	55	14,418
FRCC	23	6,841
MRO	25	691
NPCC-NE	23	6,040
NPCC-NY	34	11,181
RFC	43	8,942
SERC-Central	0	0
SERC-Delta	88	16,519
SERC-Gateway	13	561
SERC-Southeastern	8	506
SERC-VACAR	6	2,012
SPP	92	10,955
WECC-CA	56	15,439
WECC-AZ-NM-SNV	28	2,142
WECC-NWPP	8	705
WECC-RMPA	7	175
TOTAL	509	97,124

Appendix IV: Data Tables

For the resource adequacy assessment, NERC chose a range of resource categories to evaluate Planning Reserve Margins for this scenario. The range includes Deliverable Capacity Resources on the low-end and Adjusted Potential Capacity Resources on the high-end. Refer to the *Terms Used in this Report* section for detailed definitions regarding supply/resource categories.

Table IV-1: 2009 Long-Term Reliability Assessment Reference Case - 2009 Figures

	Net Internal Demand - Reference Case (MW)	Deliverable Capacity Resources - Reference Case (MW)	Adjusted Potential Capacity Resources - Reference Case (MW)	Deliverable Capacity Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	62,376	72,204	72,204	15.8%	15.8%
FRCC	42,531	51,870	51,870	22.0%	22.0%
MRO	41,306	50,308	51,098	21.8%	23.7%
NPCC-NE	27,875	33,703	33,921	20.9%	21.7%
NPCC-NY	33,233	42,968	43,658	29.3%	31.4%
RFC	169,900	215,800	217,904	27.0%	28.3%
SERC-Central	40,874	50,828	51,196	24.4%	25.3%
SERC-Delta	27,178	38,466	38,602	41.5%	42.0%
SERC-Gateway	18,947	20,306	21,117	7.2%	11.5%
SERC-Southeastern	47,789	58,745	67,788	22.9%	41.8%
SERC-VACAR	62,083	75,663	77,426	21.9%	24.7%
SPP	43,696	50,127	56,648	14.7%	29.6%
WECC-CA	58,421	71,334	71,334	22.1%	22.1%
WECC-AZ-NM-SNV	29,843	35,076	35,076	17.5%	17.5%
WECC-NWPP	41,391	56,705	56,710	37.0%	37.0%
WECC-RMPA	10,939	13,517	13,517	23.6%	23.6%
TOTAL	758,382	937,619	960,070	23.1%	26.1%

Table IV-2: 2009 Long-Term Reliability Assessment Reference Case - 2013 Projections					
	Net Internal Demand - Reference Case (MW)	Deliverable Resources - Reference Case (MW)	Adjusted Potential Resources - Reference Case (MW)	Deliverable Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	68,284	79,521	84,617	16.50%	23.90%
FRCC	44,697	57,464	57,464	28.60%	28.60%
MRO	44,482	50,218	54,299	12.90%	22.10%
NPCC-NE	29,365	34,827	37,122	18.60%	26.40%
NPCC-NY	33,861	43,381	43,957	28.10%	29.80%
RFC	183,900	219,600	228,502	19.40%	24.30%
SERC-Central	42,437	52,473	53,990	23.60%	27.20%
SERC-Delta	29,406	37,499	38,505	27.50%	30.90%
SERC-Gateway	20,032	24,834	25,645	24.00%	28.00%
SERC-Southeastern	53,099	59,987	68,949	13.00%	29.80%
SERC-VACAR	66,926	78,611	80,494	17.50%	20.30%
SPP	46,153	53,477	60,149	15.90%	30.30%
WECC-CA	60,073	89,293	89,293	48.60%	48.60%
WECC-AZ-NM-SNV	32,060	39,157	39,663	22.10%	23.70%
WECC-NWPP	44,076	57,240	57,353	29.90%	30.10%
WECC-RMPA	11,616	14,483	15,131	24.70%	30.30%
TOTAL	810,467	992,063	1,035,134	22.40%	27.70%

Table IV-3: 2009 Long-Term Reliability Assessment Reference Case - 2015 Projections					
	Net Internal Demand - Reference Case (MW)	Deliverable Resources - Reference Case (MW)	Adjusted Potential Capacity Resources - Reference Case (MW)	Deliverable Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	69,057	79,523	84,967	15.20%	23.00%
FRCC	46,579	58,235	58,235	25.00%	25.00%
MRO	45,675	49,952	54,312	9.40%	18.90%
NPCC-NE	30,115	34,777	37,487	15.50%	24.50%
NPCC-NY	34,264	43,281	43,977	26.30%	28.30%
RFC	187,700	219,800	229,546	17.10%	22.30%
SERC-Central	43,432	52,882	54,399	21.80%	25.30%
SERC-Delta	30,369	36,582	37,588	20.50%	23.80%
SERC-Gateway	20,300	24,916	25,727	22.70%	26.70%
SERC-Southeastern	55,225	62,050	71,237	12.40%	29.00%
SERC-VACAR	69,198	77,941	80,046	12.60%	15.70%
SPP	46,554	53,480	60,210	14.90%	29.30%
WECC-CA	61,564	92,405	92,405	50.10%	50.10%
WECC-AZ-NM-SNV	33,836	40,519	41,622	19.80%	23.00%
WECC-NWPP	45,306	57,546	58,061	27.00%	28.20%
WECC-RMPA	12,097	14,110	15,116	16.60%	25.00%
TOTAL	831,271	997,997	1,044,936	20.10%	25.70%

Table IV-4: 2009 Long-Term Reliability Assessment Reference Case - 2018 Projections					
	Net Internal Demand - Reference Case (MW)	Deliverable Resources - Reference Case (MW)	Adjusted Potential Capacity Resources - Reference Case (MW)	Deliverable Resources Reserve Margin - Reference Case	Adjusted Potential Capacity Resources Reserve Margin - Reference Case
ERCOT	75,019	79,525	84,969	6.00%	13.30%
FRCC	49,885	63,336	63,336	27.00%	27.00%
MRO	47,534	49,469	54,317	4.10%	14.30%
NPCC-NE	30,960	34,499	37,209	11.40%	20.20%
NPCC-NY	35,231	44,081	44,777	25.10%	27.10%
RFC	193,100	219,800	230,054	13.80%	19.10%
SERC-Central	45,288	54,410	55,927	20.10%	23.50%
SERC-Delta	31,438	36,161	37,167	15.00%	18.20%
SERC-Gateway	20,817	24,916	25,727	19.70%	23.60%
SERC-Southeastern	58,505	67,860	77,047	16.00%	31.70%
SERC-VACAR	72,814	79,025	80,880	8.50%	11.10%
SPP	48,500	53,319	60,141	9.90%	24.00%
WECC-CA	63,916	89,054	89,054	39.30%	39.30%
WECC-AZ-NM-SNV	36,382	43,381	44,819	19.20%	23.20%
WECC-NWPP	47,292	57,687	58,200	22.00%	23.10%
WECC-RMPA	12,874	15,102	16,146	17.30%	25.40%
TOTAL	869,554	1,011,624	1,059,770	16.30%	21.90%

Table IV-5: Combined Impacts - Number of Units Retired by Region and Size - 2018										
	Coal					Gas/Oil Steam				
	0-99 (MW)	100-199	200-399	>400 (MW)	Total	0-99 (MW)	100-199	200-399	>400 (MW)	Total
Moderate Case										
ERCOT	0	0	0	0	0	8	10	7	3	28
FRCC	0	1	0	0	1	5	1	2	0	8
MRO	57	0	0	0	57	24	1	0	0	25
NPCC-NE	2	0	1	0	3	5	4	0	4	13
NPCC-NY	6	1	0	0	7	5	3	0	3	11
RFC	36	10	1	0	47	19	8	3	3	33
SERC-Central	6	1	0	0	7	0	0	0	0	0
SERC-Delta	3	0	0	0	3	31	5	4	6	46
SERC-Gateway	5	1	0	0	6	12	0	0	0	12
SERC-Southeastern	5	2	0	0	7	4	1	0	0	5
SERC-VACAR	28	4	0	0	32	3	0	1	0	4
SPP-N	4	0	0	0	4	15	0	0	0	15
SPP-S	1	0	0	0	1	17	1	0	0	18
WECC-AZ-NM-SNV	0	0	0	2	2	9	3	0	0	12
WECC-CA	0	0	0	0	0	2	7	6	3	18
WECC-NWPP	4	0	0	0	4	0	0	0	0	0
WECC-RMPA	6	0	0	0	6	5	0	0	0	5
Total	163	20	2	2	187	164	44	23	22	253
Strict Case										
ERCOT	0	0	0	0	0	8	10	8	3	29
FRCC	0	1	0	0	1	5	1	2	1	9
MRO	88	7	1	0	96	24	1	0	0	25
NPCC-NE	4	3	1	0	8	5	4	0	5	14
NPCC-NY	10	3	1	0	14	5	3	0	4	12
RFC	56	44	4	1	105	19	8	3	3	33
SERC-Central	6	32	0	0	38	0	0	0	0	0
SERC-Delta	4	2	0	0	6	31	5	4	6	46
SERC-Gateway	13	9	3	0	25	12	0	0	0	12
SERC-Southeastern	5	10	5	0	20	4	1	0	0	5
SERC-VACAR	34	23	0	0	57	3	0	1	0	4
SPP-N	19	0	0	0	19	16	0	0	0	16
SPP-S	1	2	0	0	3	17	1	0	0	18
WECC-AZ-NM-SNV	0	0	0	2	2	9	3	0	0	12
WECC-CA	3	0	0	0	3	2	7	9	5	23
WECC-NWPP	4	0	0	0	4	0	0	0	0	0
WECC-RMPA	9	0	0	0	9	5	0	0	0	5
Total	256	136	15	3	410	165	44	27	27	263

Table IV-6: Combined Impacts - 2018						
	Moderate Case			Strict Case		
	Derated (MW)	Retired (MW)	Total	Derated (MW)	Retired (MW)	Total
Coal Units						
ERCOT	231	0	231	351	0	351
FRCC	124	121	245	187	121	308
MRO	534	862	1,397	612	3,733	4,345
NPCC-NE	92	466	558	79	1,034	1,113
NPCC-NY	92	302	394	68	1,214	1,282
RFC	1,965	3,285	5,250	2,266	10,888	13,154
SERC-Central	541	445	986	509	4,546	5,055
SERC-Delta	151	46	197	265	308	573
SERC-Gateway	390	289	679	442	2,894	3,336
SERC-Southeastern	423	452	875	537	2,803	3,340
SERC-VACAR	453	1,658	2,111	492	4,634	5,126
SPP	252	91	342	411	1,207	1,618
WECC-CA	12	0	12	10	81	90
WECC-AZ-NM-SNV	49	1,580	1,629	49	1,580	1,629
WECC-NWPP	109	129	239	109	129	239
WECC-RMPA	27	100	126	25	141	167
TOTAL	5,445	9,825	15,270	6,414	35,312	41,726
O/G-ST Units						
ERCOT	135	5,055	5,190	129	5,295	5,424
FRCC	65	862	927	52	1,367	1,419
MRO	0	691	691	0	691	691
NPCC-NE	104	2,504	2,608	90	2,904	2,995
NPCC-NY	261	2,937	3,198	241	3,544	3,786
RFC	0	4,563	4,563	0	4,563	4,563
SERC-Central	0	0	0	0	0	0
SERC-Delta	200	5,495	5,695	200	5,495	5,695
SERC-Gateway	0	405	405	0	405	405
SERC-Southeastern	0	329	329	0	329	329
SERC-VACAR	23	408	431	23	408	431
SPP	19	881	901	17	942	960
WECC-CA	218	5,041	5,259	172	6,867	7,039
WECC-AZ-NM-SNV	5	773	778	5	773	778
WECC-NWPP	3	0	3	3	0	3
WECC-RMPA	0	84	84	0	84	84
TOTAL	1,033	30,027	31,061	934	33,667	34,601

Appendix IV: Data Tables

Table IV-7: 316(b) Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.5% – 23.9%	0.0 – 0.0
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.9% – 22.1%	0.0 – 0.0
NPCC-NE	18.6% – 26.4%	0.0 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.4% – 24.3%	0.0 – 0.0	19.4% – 24.3%	0.0 – 0.0
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.6% – 27.2%	0.0 – 0.0
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.5% – 30.9%	0.0 – 0.0
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	24.0% – 28.0%	0.0 – 0.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	13.0% – 29.8%	0.0 – 0.0
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	17.5% – 20.3%	0.0 – 0.0
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.4% – 27.7%	0.0 – 0.0	22.4% – 27.7%	0.0 – 0.0

Table IV-8: MACT Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.5% – 23.9%	0.0 – 0.0
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.9% – 22.1%	0.0 – 0.0
NPCC-NE	18.6% – 26.4%	0.0 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.4% – 24.3%	0.0 – 0.0	19.4% – 24.3%	0.0 – 0.0
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.6% – 27.2%	0.0 – 0.0
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.5% – 30.9%	0.0 – 0.0
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	24.0% – 28.0%	0.0 – 0.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	13.0% – 29.8%	0.0 – 0.0
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	17.5% – 20.3%	0.0 – 0.0
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.4% – 27.7%	0.0 – 0.0	22.4% – 27.7%	0.0 – 0.0

Table IV-9: CATR Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.4% – 23.8%	-0.1 – -0.1
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.2% – 21.4%	-0.7 – -0.7
NPCC-NE	18.0% – 26.4%	-0.6 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.2% – 24.3%	-0.2 – 0.0	18.9% – 23.7%	-0.5 – -0.5
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.3% – 26.9%	-0.4 – -0.4
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.1% – 30.5%	-0.4 – -0.4
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	23.3% – 27.4%	-0.6 – -0.6
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	12.5% – 29.3%	-0.5 – -0.5
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	16.6% – 19.4%	-0.9 – -0.9
SPP	15.9% – 30.3%	0.0 – 0.0	15.6% – 30.0%	-0.3 – -0.3
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.3% – 27.7%	-0.1 – 0.0	22.1% – 27.4%	-0.3 – -0.3

Table IV-10: CCR Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.5% – 23.9%	0.0 – 0.0
FRCC	28.6% – 28.6%	0.0 – 0.0	28.6% – 28.6%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	12.9% – 22.1%	0.0 – 0.0
NPCC-NE	18.6% – 26.4%	0.0 – 0.0	18.6% – 26.4%	0.0 – 0.0
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	28.1% – 29.8%	0.0 – 0.0
RFC	19.4% – 24.3%	0.0 – 0.0	19.4% – 24.3%	0.0 – 0.0
SERC-Central	23.6% – 27.2%	0.0 – 0.0	23.6% – 27.2%	0.0 – 0.0
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.5% – 30.9%	0.0 – 0.0
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	24.0% – 28.0%	0.0 – 0.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	13.0% – 29.8%	0.0 – 0.0
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	17.5% – 20.3%	0.0 – 0.0
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.6% – 48.6%	0.0 – 0.0
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.4% – 27.7%	0.0 – 0.0	22.4% – 27.7%	0.0 – 0.0

Appendix IV: Data Tables

Table IV-11: Combined Impacts - 2013				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	16.5% – 23.9%	0.0 – 0.0	16.3% – 23.8%	-0.1 – -0.1
FRCC	28.6% – 28.6%	0.0 – 0.0	28.5% – 28.5%	0.0 – 0.0
MRO	12.9% – 22.1%	0.0 – 0.0	10.1% – 19.3%	-2.7 – -2.7
NPCC-NE	18.0% – 25.9%	-0.6 – -0.6	16.7% – 24.6%	-1.9 – -1.9
NPCC-NY	28.1% – 29.8%	0.0 – 0.0	27.3% – 29.0%	-0.8 – -0.8
RFC	19.2% – 24.0%	-0.2 – -0.2	17.6% – 22.4%	-1.9 – -1.9
SERC-Central	23.6% – 27.2%	0.0 – 0.0	22.8% – 26.4%	-0.9 – -0.9
SERC-Delta	27.5% – 30.9%	0.0 – 0.0	27.0% – 30.4%	-0.5 – -0.5
SERC-Gateway	24.0% – 28.0%	0.0 – 0.0	22.9% – 27.0%	-1.0 – -1.0
SERC-Southeastern	13.0% – 29.8%	0.0 – 0.0	12.1% – 28.9%	-0.9 – -0.9
SERC-VACAR	17.5% – 20.3%	0.0 – 0.0	15.5% – 18.3%	-1.9 – -1.9
SPP	15.9% – 30.3%	0.0 – 0.0	15.9% – 30.3%	0.0 – 0.0
WECC-CA	48.6% – 48.6%	0.0 – 0.0	48.4% – 48.4%	-0.3 – -0.3
WECC-AZ-NM-SNV	22.1% – 23.7%	0.0 – 0.0	22.1% – 23.7%	0.0 – 0.0
WECC-NWPP	29.9% – 30.1%	0.0 – 0.0	29.9% – 30.1%	0.0 – 0.0
WECC-RMPA	24.7% – 30.3%	0.0 – 0.0	24.7% – 30.3%	0.0 – 0.0
TOTAL	22.3% – 27.7%	-0.1 – -0.1	21.4% – 26.7%	-1.0 – -1.0

Table IV-12: 316(b) Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	14.1% – 22.0%	-1.1 – -1.1	13.8% – 21.7%	-1.4 – -1.4
FRCC	24.7% – 24.7%	-0.3 – -0.3	24.7% – 24.7%	-0.3 – -0.3
MRO	7.6% – 17.2%	-1.7 – -1.7	7.6% – 17.1%	-1.8 – -1.8
NPCC-NE	12.0% – 21.0%	-3.5 – -3.5	12.0% – 21.0%	-3.5 – -3.5
NPCC-NY	23.5% – 25.5%	-2.9 – -2.9	23.5% – 25.5%	-2.9 – -2.9
RFC	16.2% – 21.4%	-0.9 – -0.9	16.2% – 21.4%	-0.9 – -0.9
SERC-Central	21.1% – 24.6%	-0.6 – -0.6	21.1% – 24.6%	-0.6 – -0.6
SERC-Delta	14.3% – 17.7%	-6.1 – -6.1	14.3% – 17.7%	-6.1 – -6.1
SERC-Gateway	20.0% – 24.0%	-2.7 – -2.7	20.0% – 24.0%	-2.7 – -2.7
SERC-Southeastern	11.8% – 28.5%	-0.5 – -0.5	11.9% – 28.5%	-0.5 – -0.5
SERC-VACAR	12.4% – 15.4%	-0.3 – -0.3	12.3% – 15.4%	-0.3 – -0.3
SPP	13.6% – 28.0%	-1.3 – -1.3	13.5% – 28.0%	-1.4 – -1.4
WECC-CA	48.8% – 48.8%	-1.3 – -1.3	48.8% – 48.8%	-1.3 – -1.3
WECC-AZ-NM-SNV	19.7% – 22.9%	-0.1 – -0.1	19.7% – 22.9%	-0.1 – -0.1
WECC-NWPP	26.8% – 28.0%	-0.2 – -0.2	26.8% – 28.0%	-0.2 – -0.2
WECC-RMPA	16.2% – 24.6%	-0.4 – -0.4	16.0% – 24.3%	-0.6 – -0.6
TOTAL	18.8% – 24.5%	-1.2 – -1.2	18.8% – 24.4%	-1.3 – -1.3

Table IV-13: MACT Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	15.0% – 22.9%	-0.1 – -0.1	15.0% – 22.9%	-0.1 – -0.1
FRCC	25.0% – 25.0%	0.0 – 0.0	24.6% – 24.6%	-0.4 – -0.4
MRO	8.6% – 18.2%	-0.7 – -0.7	7.4% – 16.9%	-2.0 – -2.0
NPCC-NE	15.5% – 24.5%	0.0 – 0.0	13.3% – 22.3%	-2.2 – -2.2
NPCC-NY	26.3% – 28.3%	0.0 – 0.0	24.2% – 26.3%	-2.1 – -2.1
RFC	16.5% – 21.7%	-0.6 – -0.6	13.6% – 18.8%	-3.5 – -3.5
SERC-Central	21.5% – 24.9%	-0.3 – -0.3	18.8% – 22.2%	-3.0 – -3.0
SERC-Delta	20.2% – 23.5%	-0.3 – -0.3	19.9% – 23.2%	-0.5 – -0.5
SERC-Gateway	22.2% – 26.1%	-0.6 – -0.6	20.4% – 24.4%	-2.3 – -2.3
SERC-Southeastern	12.0% – 28.7%	-0.3 – -0.3	9.6% – 26.2%	-2.8 – -2.8
SERC-VACAR	12.0% – 15.0%	-0.7 – -0.7	8.4% – 11.5%	-4.2 – -4.2
SPP	14.6% – 29.1%	-0.3 – -0.3	14.5% – 28.9%	-0.4 – -0.4
WECC-CA	50.1% – 50.1%	0.0 – 0.0	50.1% – 50.1%	0.0 – 0.0
WECC-AZ-NM-SNV	19.6% – 22.9%	-0.1 – -0.1	14.9% – 18.2%	-4.8 – -4.8
WECC-NWPP	26.8% – 27.9%	-0.2 – -0.2	26.6% – 27.7%	-0.4 – -0.4
WECC-RMPA	16.5% – 24.8%	-0.1 – -0.1	15.7% – 24.0%	-0.9 – -0.9
TOTAL	19.7% – 25.4%	-0.3 – -0.3	17.9% – 23.6%	-2.1 – -2.1

Appendix IV: Data Tables

Table IV-14: CATR Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	15.2% – 23.0%	0.0 – 0.0	15.0% – 22.9%	-0.1 – -0.1
FRCC	25.0% – 25.0%	0.0 – 0.0	25.0% – 25.0%	0.0 – 0.0
MRO	9.3% – 18.8%	-0.1 – -0.1	6.7% – 16.2%	-2.7 – -2.7
NPCC-NE	14.9% – 23.9%	-0.5 – -0.5	14.2% – 23.2%	-1.3 – -1.3
NPCC-NY	26.3% – 28.3%	0.0 – 0.0	26.1% – 28.1%	-0.2 – -0.2
RFC	16.2% – 21.4%	-0.9 – -0.9	15.6% – 20.8%	-1.5 – -1.5
SERC-Central	21.7% – 25.2%	0.0 – 0.0	21.1% – 24.6%	-0.7 – -0.7
SERC-Delta	20.5% – 23.8%	0.0 – 0.0	19.9% – 23.3%	-0.5 – -0.5
SERC-Gateway	18.4% – 22.4%	-4.3 – -4.3	21.7% – 25.7%	-1.0 – -1.0
SERC-Southeastern	12.3% – 28.9%	-0.1 – -0.1	11.5% – 28.1%	-0.9 – -0.9
SERC-VACAR	12.6% – 15.7%	0.0 – 0.0	10.9% – 14.0%	-1.7 – -1.7
SPP	14.9% – 29.3%	0.0 – 0.0	14.2% – 28.7%	-0.7 – -0.7
WECC-CA	50.1% – 50.1%	0.0 – 0.0	50.1% – 50.1%	0.0 – 0.0
WECC-AZ-NM-SNV	19.8% – 23.0%	0.0 – 0.0	19.8% – 23.0%	0.0 – 0.0
WECC-NWPP	27.0% – 28.2%	0.0 – 0.0	27.0% – 28.2%	0.0 – 0.0
WECC-RMPA	16.6% – 25.0%	0.0 – 0.0	16.6% – 25.0%	0.0 – 0.0
TOTAL	19.7% – 25.4%	-0.3 – -0.3	19.2% – 24.8%	-0.9 – -0.9

Table IV-15: CCR Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	15.2% – 23.0%	0.0 – 0.0	15.2% – 23.0%	0.0 - 0.0
FRCC	25.0% – 25.0%	0.0 – 0.0	25.0% – 25.0%	0.0 - 0.0
MRO	9.4% – 18.9%	0.0 – 0.0	9.4% – 18.9%	0.0 - 0.0
NPCC-NE	15.5% – 24.5%	0.0 – 0.0	15.5% – 24.5%	0.0 - 0.0
NPCC-NY	26.3% – 28.3%	0.0 – 0.0	26.3% – 28.3%	0.0 - 0.0
RFC	17.1% – 22.3%	0.0 – 0.0	17.1% – 22.3%	0.0 - 0.0
SERC-Central	21.8% – 25.3%	0.0 – 0.0	21.6% – 25.1%	-0.2 - -0.2
SERC-Delta	20.5% – 23.8%	0.0 – 0.0	20.5% – 23.8%	0.0 - 0.0
SERC-Gateway	22.7% – 26.7%	0.0 – 0.0	22.3% – 26.3%	-0.4 - -0.4
SERC-Southeastern	12.1% – 28.8%	-0.2 – -0.2	12.1% – 28.8%	-0.2 - -0.2
SERC-VACAR	12.6% – 15.7%	0.0 – 0.0	12.6% – 15.7%	0.0 - 0.0
SPP	14.9% – 29.3%	0.0 – 0.0	14.9% – 29.3%	0.0 - 0.0
WECC-CA	50.1% – 50.1%	0.0 – 0.0	50.1% – 50.1%	0.0 - 0.0
WECC-AZ-NM-SNV	19.8% – 23.0%	0.0 – 0.0	19.8% – 23.0%	0.0 - 0.0
WECC-NWPP	27.0% – 28.2%	0.0 – 0.0	27.0% – 28.2%	0.0 - 0.0
WECC-RMPA	16.6% – 25.0%	0.0 – 0.0	16.6% – 25.0%	0.0 - 0.0
TOTAL	20.0% – 25.7%	0.0 – 0.0	20.0% – 25.7%	0.0 - 0.0

Table IV-16: Combined Impacts - 2015				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	7.5% – 15.4%	-7.7 – -7.7	6.8% – 14.7%	-8.4 – -8.4
FRCC	23.0% – 23.0%	-2.0 – -2.0	21.3% – 21.3%	-3.7 – -3.7
MRO	5.9% – 15.5%	-3.5 – -3.5	-1.7% – 7.9%	-11.0 – -11.0
NPCC-NE	7.2% – 16.2%	-8.3 – -8.3	1.8% – 10.8%	-13.6 – -13.6
NPCC-NY	17.4% – 19.5%	-8.9 – -8.9	11.5% – 13.6%	-14.8 – -14.8
RFC	14.2% – 19.4%	-2.9 – -2.9	7.2% – 12.4%	-9.9 – -9.9
SERC-Central	21.0% – 24.5%	-0.7 – -0.7	10.1% – 13.6%	-11.6 – -11.6
SERC-Delta	1.9% – 5.2%	-18.6 – -18.6	-0.2% – 3.1%	-20.6 – -20.6
SERC-Gateway	19.6% – 23.6%	-3.1 – -3.1	1.5% – 5.5%	-21.3 – -21.3
SERC-Southeastern	11.3% – 27.9%	-1.1 – -1.1	5.7% – 22.4%	-6.6 – -6.6
SERC-VACAR	11.1% – 14.2%	-1.5 – -1.5	4.6% – 7.6%	-8.0 – -8.0
SPP	12.7% – 27.1%	-2.2 – -2.2	9.3% – 23.8%	-5.5 – -5.5
WECC-CA	44.3% – 44.3%	-5.8 – -5.8	39.3% – 39.3%	-10.8 – -10.8
WECC-AZ-NM-SNV	17.3% – 20.6%	-2.4 – -2.4	12.6% – 15.9%	-7.1 – -7.1
WECC-NWPP	26.5% – 27.6%	-0.5 – -0.5	26.5% – 27.6%	-0.5 – -0.5
WECC-RMPA	14.9% – 23.2%	-1.7 – -1.7	14.6% – 22.9%	-2.1 – -2.1
TOTAL	16.1% – 21.7%	-4.0 – -4.0	10.8% – 16.4%	-9.3 – -9.3

Table IV-17: 316(b) Impacts - 2018

	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	-1.2% – 6.1%	-7.2 – -7.2	-1.5% – 5.8%	-7.5 – -7.5
FRCC	24.9% – 24.9%	-2.1 – -2.1	23.9% – 23.9%	-3.1 – -3.1
MRO	0.6% – 10.8%	-3.5 – -3.5	0.6% – 10.8%	-3.5 – -3.5
NPCC-NE	2.7% – 11.5%	-8.7 – -8.7	1.5% – 10.2%	-10.0 – -10.0
NPCC-NY	15.6% – 17.6%	-9.5 – -9.5	13.9% – 15.9%	-11.2 – -11.2
RFC	10.2% – 15.5%	-3.6 – -3.6	10.1% – 15.4%	-3.7 – -3.7
SERC-Central	19.1% – 22.5%	-1.0 – -1.0	19.1% – 22.5%	-1.0 – -1.0
SERC-Delta	-3.4% – -0.2%	-18.5 – -18.5	-3.4% – -0.2%	-18.5 – -18.5
SERC-Gateway	15.7% – 19.6%	-3.9 – -3.9	15.7% – 19.6%	-4.0 – -4.0
SERC-Southeastern	14.8% – 30.5%	-1.2 – -1.2	14.8% – 30.5%	-1.2 – -1.2
SERC-VACAR	7.1% – 9.6%	-1.4 – -1.4	7.1% – 9.6%	-1.5 – -1.5
SPP	7.7% – 21.8%	-2.2 – -2.2	7.6% – 21.7%	-2.3 – -2.3
WECC-CA	31.1% – 31.1%	-8.3 – -8.3	28.3% – 28.3%	-11.1 – -11.1
WECC-AZ-NM-SNV	17.1% – 21.1%	-2.1 – -2.1	17.1% – 21.1%	-2.1 – -2.1
WECC-NWPP	21.6% – 22.7%	-0.4 – -0.4	21.6% – 22.7%	-0.4 – -0.4
WECC-RMPA	15.8% – 23.9%	-1.6 – -1.6	15.8% – 23.9%	-1.6 – -1.6
TOTAL	12.0% – 17.6%	-4.3 – -4.3	11.6% – 17.1%	-4.7 – -4.7

Table IV-18: MACT Impacts - 2018

	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	5.9% – 13.2%	-0.1 – -0.1	5.9% – 13.2%	-0.1 – -0.1
FRCC	26.9% – 26.9%	0.0 – 0.0	26.6% – 26.6%	-0.4 – -0.4
MRO	2.3% – 12.5%	-1.8 – -1.8	2.2% – 12.4%	-1.9 – -1.9
NPCC-NE	11.3% – 20.1%	-0.1 – -0.1	9.3% – 18.1%	-2.1 – -2.1
NPCC-NY	24.9% – 26.9%	-0.2 – -0.2	23.1% – 25.1%	-2.0 – -2.0
RFC	12.2% – 17.6%	-1.6 – -1.6	10.4% – 15.7%	-3.4 – -3.4
SERC-Central	19.4% – 22.7%	-0.8 – -0.8	17.3% – 20.6%	-2.9 – -2.9
SERC-Delta	14.7% – 17.9%	-0.4 – -0.4	14.5% – 17.7%	-0.5 – -0.5
SERC-Gateway	18.8% – 22.6%	-0.9 – -0.9	17.4% – 21.3%	-2.3 – -2.3
SERC-Southeastern	15.4% – 31.1%	-0.6 – -0.6	13.3% – 29.1%	-2.6 – -2.6
SERC-VACAR	7.0% – 9.6%	-1.5 – -1.5	4.5% – 7.1%	-4.0 – -4.0
SPP	9.6% – 23.6%	-0.4 – -0.4	9.6% – 23.6%	-0.4 – -0.4
WECC-CA	39.3% – 39.3%	0.0 – 0.0	39.3% – 39.3%	0.0 – 0.0
WECC-AZ-NM-SNV	14.8% – 18.7%	-4.5 – -4.5	14.8% – 18.7%	-4.5 – -4.5
WECC-NWPP	21.6% – 22.6%	-0.4 – -0.4	21.6% – 22.6%	-0.4 – -0.4
WECC-RMPA	16.5% – 24.6%	-0.9 – -0.9	16.5% – 24.6%	-0.9 – -0.9
TOTAL	15.4% – 20.9%	-1.0 – -1.0	14.3% – 19.8%	-2.0 – -2.0

Table IV-19: CATR Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	6.0% – 13.3%	0.0 - 0.0	5.9% - 13.1%	-0.1 - -0.1
FRCC	27.0% – 27.0%	0.0 - 0.0	26.9% - 26.9%	0.0 - 0.0
MRO	4.0% – 14.2%	-0.1 - -0.1	1.5% - 11.7%	-2.6 - -2.6
NPCC-NE	10.9% – 19.7%	-0.5 - -0.5	10.2% - 18.9%	-1.2 - -1.2
NPCC-NY	25.1% – 27.1%	0.0 - 0.0	24.9% - 26.9%	-0.2 - -0.2
RFC	12.9% – 18.2%	-0.9 - -0.9	12.4% - 17.7%	-1.4 - -1.4
SERC-Central	20.1% – 23.5%	0.0 - 0.0	19.5% - 22.9%	-0.6 - -0.6
SERC-Delta	15.0% – 18.2%	0.0 - 0.0	14.5% - 17.7%	-0.5 - -0.5
SERC-Gateway	15.5% – 19.4%	-4.2 - -4.2	18.7% - 22.6%	-1.0 - -1.0
SERC-Southeastern	15.9% – 31.6%	-0.1 - -0.1	15.2% - 30.9%	-0.8 - -0.8
SERC-VACAR	8.5% – 11.1%	0.0 - 0.0	6.9% - 9.4%	-1.6 - -1.6
SPP	9.9% – 24.0%	0.0 - 0.0	9.3% - 23.3%	-0.7 - -0.7
WECC-CA	39.3% – 39.3%	0.0 - 0.0	39.3% - 39.3%	0.0 - 0.0
WECC-AZ-NM-SNV	19.2% – 23.2%	0.0 - 0.0	19.2% - 23.2%	0.0 - 0.0
WECC-NWPP	22.0% – 23.1%	0.0 - 0.0	22.0% - 23.1%	0.0 - 0.0
WECC-RMPA	17.3% – 25.4%	0.0 - 0.0	17.3% - 25.4%	0.0 - 0.0
TOTAL	16.0% – 21.5%	-0.3 - -0.3	15.5% - 21.1%	-0.8 - -0.8

Table IV-20: CCR Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	6.0% – 13.3%	0.0 – 0.0	6.0% – 13.3%	0.0 – 0.0
FRCC	27.0% – 27.0%	0.0 – 0.0	27.0% – 27.0%	0.0 – 0.0
MRO	4.1% – 14.3%	0.0 – 0.0	3.9% – 14.1%	-0.2 – -0.2
NPCC-NE	11.4% – 20.2%	0.0 – 0.0	11.4% – 20.2%	0.0 – 0.0
NPCC-NY	25.1% – 27.1%	0.0 – 0.0	25.1% – 27.1%	0.0 – 0.0
RFC	13.8% – 19.1%	0.0 – 0.0	13.8% – 19.1%	0.0 – 0.0
SERC-Central	20.0% – 23.3%	-0.2 – -0.2	20.0% – 23.3%	-0.2 – -0.2
SERC-Delta	15.0% – 18.2%	0.0 – 0.0	15.0% – 18.2%	-0.1 – -0.1
SERC-Gateway	19.3% – 23.2%	-0.4 – -0.4	19.3% – 23.2%	-0.4 – -0.4
SERC-Southeastern	15.8% – 31.5%	-0.2 – -0.2	15.8% – 31.5%	-0.2 – -0.2
SERC-VACAR	8.5% – 11.1%	0.0 – 0.0	8.5% – 11.1%	0.0 – 0.0
SPP	9.9% – 24.0%	0.0 – 0.0	9.9% – 24.0%	0.0 – 0.0
WECC-CA	39.3% – 39.3%	0.0 – 0.0	39.3% – 39.3%	0.0 – 0.0
WECC-AZ-NM-SNV	19.2% – 23.2%	0.0 – 0.0	19.2% – 23.2%	0.0 – 0.0
WECC-NWPP	22.0% – 23.1%	0.0 – 0.0	22.0% – 23.1%	0.0 – 0.0
WECC-RMPA	17.3% – 25.4%	0.0 – 0.0	17.3% – 25.4%	0.0 – 0.0
TOTAL	16.3% – 21.8%	0.0 – 0.0	16.3% – 21.8%	0.0 – 0.0

Table IV-21: Combined Impacts - 2018				
	Moderate Case		Strict Case	
	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin	Resulting Reserve Margin (%) (DCR to APCR)	Percentage Point Change in Reserve Margin
ERCOT	-1.2% — 6.0%	-7.2 — -7.2	-1.7% — 5.6%	-7.7 — -7.7
FRCC	24.6% — 24.6%	-2.3 — -2.3	23.5% — 23.5%	-3.5 — -3.5
MRO	-0.3% — 9.9%	-4.4 — -4.4	-6.5% — 3.7%	-10.6 — -10.6
NPCC-NE	1.2% — 10.0%	-10.2 — -10.2	-1.8% — 6.9%	-13.3 — -13.3
NPCC-NY	14.9% — 16.9%	-10.2 — -10.2	10.7% — 12.7%	-14.4 — -14.4
RFC	8.7% — 14.1%	-5.1 — -5.1	4.7% — 10.0%	-9.2 — -9.2
SERC-Central	18.0% — 21.3%	-2.2 — -2.2	9.0% — 12.3%	-11.2 — -11.2
SERC-Delta	-3.7% — -0.5%	-18.7 — -18.7	-4.9% — -1.7%	-19.9 — -19.9
SERC-Gateway	14.5% — 18.4%	-5.2 — -5.2	1.7% — 5.6%	-18.0 — -18.0
SERC-Southeastern	13.9% — 29.6%	-2.1 — -2.1	9.7% — 25.4%	-6.3 — -6.3
SERC-VACAR	5.0% — 7.6%	-3.5 — -3.5	0.9% — 3.4%	-7.6 — -7.6
SPP	7.4% — 21.4%	-2.6 — -2.6	4.6% — 18.7%	-5.3 — -5.3
WECC-CA	31.1% — 31.1%	-8.3 — -8.3	28.2% — 28.2%	-11.2 — -11.2
WECC-AZ-NM-SNV	12.6% — 16.6%	-6.6 — -6.6	12.6% — 16.6%	-6.6 — -6.6
WECC-NWPP	21.5% — 22.6%	-0.5 — -0.5	21.5% — 22.6%	-0.5 — -0.5
WECC-RMPA	15.7% — 23.8%	-1.6 — -1.6	15.4% — 23.5%	-1.9 — -1.9
TOTAL	11.0% — 16.5%	-5.3 — -5.3	7.6% — 13.1%	-8.8 — -8.8

Appendix V: Related Study Work and References

Related Study Work For 316(b)

The U.S. Senate Committee on Appropriations, Subcommittee on Energy and Water Development, requested the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE or Department) to examine the impacts to electricity reliability of requiring generators with once-through cooling systems to be replaced with closed-cycle cooling towers.

DOE provided NERC with a list of steam generation units that would be required to retrofit to cooling towers. DOE requested NERC to model the reliability impacts of the cooling tower mandate using certain assumptions. NERC provided DOE with its results in a white paper, 2008-*2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generating Facilities.*

In the white paper, NERC concluded that once the deadline for the cooling tower retrofits has passed, the generation losses resulting from the requirement would exacerbate a potential decline in electric Planning Reserve Margins needed to ensure reliable delivery of electricity. Generally, the goal for NERC Regions is to have the equivalent of between 10 and 15 percent of their peak generation demand available to meet contingencies. NERC projects overall capacity reserve margins to fall to 14.7 percent by 2015, assuming only planned generation is built. However, upon assessing the impact of a cooling tower mandate, NERC projects that, "U.S. resource margins will drop from 14.7 percent to 10.4 percent when both the retired units and auxiliary loads due to retrofitting were compared to the *Reference Case*."

The following assumptions were used for this assessment:

Assumptions specified by DOE:

- Close-loop cooling systems will be added to all nuclear units. Capacity factors can be used as a proxy for economic suitability for retrofit
- Unit Retirements/Retrofits were based on the following capacity factors from 2006:
  - Units with a capacity factor less than 35 percent are assumed to be retired.
  - Units with a capacity factor greater than or equal to 0.35 were derated by four percent of maximum rated (nameplate) capacity.
  - 60 percent of retirements/retrofits was projected to begin in 2013, 20 percent in 2014 and 20 percent in 2015.
- Plants deemed "difficult to retrofit" due to geographical limitations (e.*g.* land-locked, space and permitting constraints) could result in early retirement. This assessment does not assume their early retirement.
- No new plants are built to replace capacity lost to retired units or auxiliary loads.
- Retrofits are instantaneous, with no capacity shortfalls due to plant shutdowns.
- Plants with a zero capacity factor (inactive or not yet built) are not assessed. These plants are not included in the Region's *Reference Case*.

Appendix V: Related Study Work and References

Assumptions specified by NERC:

- The NERC Reference Margin Level adopted the Regional/subregional Target Capacity Margin. If not available, the NERC Reference Margin Level is based on supply-side fuel: 13 percent for thermal systems and 9 percent for hydro (Capacity Margin).
- Unit Retirement/Retrofit capacity reduction comparison is based against "Adjusted Potential Resources", calculated with all Existing Capacity and probable Planned Additions, Proposed Additions, and Net Transactions.
- Units already expected to retire between 2010 and 2015 were not considered part of the capacity reduction as they are already factored into the Region's projections.

NERC reviewed the impact of either retrofitting units with existing once-through-cooling systems to closed-loop cooling systems (resulting in four percent reduction in nameplate capacity) or unit retirements (capacity factor less than 35 percent) on NERC-US and Regional capacity margins for 2008–2017. Based on a worst-case view, NERC-US Adjusted Potential Resources may be impacted up to 49,000 MW, reducing the Adjusted Potential Resource Margin by 4.3 percent and some areas may require more resources to offset capacity reductions and maintain the reliability of the bulk power system. Some subregions, such as WECC-CA, NPCC-NE, ERCOT, SERC-Central and NPCC-NY, experience significant impacts.

Table V-1: 2015 US Summer Peak Potential Retrofit/Retirement Effects

	Adjusted Potential Resources (MW)	Reduction due to Retirement (MW)	Derate due to Retrofit (MW)	NERC Reference Margin Level	Adjusted Potential Resources Margin	Margin Reduction	Reduced Margin
United States							
WECC - CA-MX US	72,293	10,137	289	13.2%	12.7%	14.7%	-2.0%
NPCC - New England	31,673	2,827	428	13.0%	10.0%	10.3%	-0.3%
ERCOT	86,436	10,919	542	11.1%	15.9%	12.9%	3.0%
NPCC US	72,750	6,481	990	13.0%	13.3%	9.9%	3.4%
WECC US	176,944	10,177	314	12.3%	11.1%	5.6%	5.5%
NPCC - New York	41,077	3,654	561	13.0%	15.9%	9.6%	6.3%
SERC - VACAR	78,182	553	1,032	13.0%	11.0%	1.8%	9.2%
WECC - RMPA	15,609	40	0	10.5%	10.2%	0.2%	10.0%
SERC - Central	54,548	0	949	13.0%	12.6%	1.5%	11.0%
SERC - Delta	41,259	4,266	466	13.0%	21.5%	10.2%	11.4%
RFC	230,062	3,339	2,863	12.8%	14.5%	2.4%	12.1%
SERC	269,599	6,054	3,307	13.0%	15.6%	3.0%	12.5%
SERC - Southeastern	66,675	675	357	13.0%	13.9%	1.4%	12.6%
MRO US	55,582	529	612	13.0%	15.1%	1.8%	13.3%
FRCC	63,170	1,267	454	13.0%	18.7%	2.3%	16.4%
WECC - NWPP	51,861	0	25	11.9%	16.9%	0.0%	16.8%
SPP	63,700	817	257	12.0%	24.1%	1.3%	22.8%
SERC - Gateway	28,935	560	502	13.0%	28.8%	2.7%	26.1%
Total-NERC US	**1,018,243**	**39,583**	**9,339**	**13.0%**	**14.7%**	**4.3%**	**10.4%**

In comparing the results of the prior collaborative DOE/NERC assessment to the results in this report, impacts of similar magnitudes were found. Further, the areas (Regions/subregions) of concern highlighted in the prior assessment are aligned with those identified in this assessment.

EPRI Study Work For CCR:

EPRI conducted a screening assessment of the potential impact of EPA's expected proposals for management of CCR prior to publication of the draft rule.[42] This assessment indicated that 40 to 97 GW of coal-fired capacity could be "at risk" for retirement based on the increased costs associated with such a rule. The methods for estimating compliance costs at the generating unit level are similar to methods discussed in this report, with three significant differences:

- the sample of coal-fired generating units included in the assessment;
- the definition of the term "at risk" capacity; and
- some aspects of the cost assignment logic for Subtitle C (hazardous waste) management of CCRs.

Coal-Fired Capacity Assumptions

The total capacity represented by the units included in the EPRI analysis differed from the total capacity of the units included in the NERC assessment. Included in the EPRI analysis--but excluded from NERC's--are smaller units not in the bulk power system, planned coal-fired units not currently operating but scheduled to come online during the 20-year EPRI study horizon, and units that have recently announced early retirements. Since EPRI's analysis in 2009, several utilities have announced plans to retire older coal-fired generating units. Combined, the units included in EPRI's analysis, but excluded from the NERC assessment, represent 20 GW of capacity.

Definition of "at risk" Coal Capacity

The EPRI study was a screening-level economic analysis, intended to identify individual generating units that were predicted to be no longer profitable under a Subtitle C regulation. Any unit that would no longer be profitable was defined as "at risk." "At risk" in this context means that a decision would have to be made with respect to the generating unit: early retirement, repower, purchase power, or continue operation at a loss or at higher market prices. NERC, however, starts with the premise that reliability cannot be compromised and that for many units shutdown is not an option (particularly base-load units) without major disruption to the power grid. Thus, NERC's assessment compared the cost of compliance with Subtitle C requirements to the cost of natural gas-fired replacement power in order to determine which decision would be the most economical for a generating unit; only those units where compliance costs exceeded repowering costs were considered candidates for shutdown and thus deemed "at risk" for retirement.

Subtitle C Cost Assumptions

In assessing the cost of hazardous waste regulation on power plants, EPRI considered costs that NERC did not include in its assessment. One was the cost of off-site disposal at a commercial facility. NERC's assessment assumed all power plants would locate and construct Subtitle C landfills on or near the power plant property. While some states do not currently allow establishment of hazardous waste landfills within the state, NERC assumed that provisions

[42] EPRI, 2009, Testimony at the House Subcommittee on Energy and Environment Hearing on "Drinking Water and Public Health Impacts of Coal Combustion Waste Disposal," Washington DC, December 10, 2009. http://mydocs.epri.com/docs/CorporateDocuments/SectorPages/Portfolio/Environment/Ken%20Ladwig%20Written%20Testimony%20USHouse-E%26E%2010Dec2009%20FINAL.pdf

would be made to facilitate permitting of these Subtitle C facilities. Based on current disposal patterns, interviews with several utilities, and site-specific conditions such as land availability and watershed restrictions, EPRI assumed that a percentage of plants would be forced to dispose of CCRs in off-site commercial facilities, at higher costs for both transportation and disposal. The EPRI analysis also included special handling costs at the power plant to meet Subtitle C requirements. The NERC assessment did not include any special handling costs at the plant nor engineering retrofits that may be necessary for meeting Subtitle C standards. Finally, the NERC assessment assumed continued CCR utilization at current rates; EPRI ran simulations with both continued CCR use at the same rate and no CCR use.

Follow-on Steps

In their regulatory proposal, EPA requested additional information on both off-site disposal costs and "upstream" management and storage costs associated with Subtitle C regulation. In response to the EPA's request for additional cost data, EPRI is in the process of developing detailed engineering costs for Subtitle C regulation at the power plant as well as at CCR disposal sites. EPRI will share the engineering information and cost data with NERC when it is available. EPRI will prepare a technical report with the engineering and cost data in 4Q 2010 that will be publicly available.

Terms Used in This Report

Adjusted Potential Capacity Resources — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources (reduced by a confidence factor), Conceptual Resources (reduced by a confidence factor), and net provisional transactions minus all derates. (MW)

Adjusted Potential Reserve Margin (%) — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources (reduced by a confidence factor), Conceptual Resources (reduced by a confidence factor), and net provisional transactions minus all derates and Net Internal Demand shown as a percent of Net Internal Demand.

Capacity Categories — *See **Existing Generation Resources, Future Generation Resources,** and **Conceptual Generation Resources***.

Conceptual Generation Resources — This category includes generation resources that are not included in *Existing Generation Resources* or *Future Generation Resources*, but have been identified and/or announced on a resource planning basis through one or more of the following sources:

1. Corporate announcement
2. Entered into or is in the early stages of an approval process
3. Is in a generator interconnection (or other) queue for study
4. "Place-holder" generation for use in modeling, such as generator modeling needed to support NERC Standard TPL analysis, as well as, integrated resource planning resource studies.

Resources included in this category may be adjusted using a confidence factor (%) to reflect uncertainties associated with siting, project development or queue position.

Deliverable Capacity Resources — Existing, Certain and Net Firm Transactions plus Future, Planned capacity resources plus Expected Imports, minus Expected Exports. (MW)

Deliverable Reserve Margin (%) — Deliverable Capacity Resources minus Net Internal Demand shown as a percent of Net Internal Demand.

Demand — *See **Net Internal Demand***, and ***Total Internal Demand***

Demand Response — Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Derate (Capacity) — The amount of capacity that is expected to be unavailable on seasonal peak.

Existing, Certain (Existing Generation Resources) — Existing generation resources available to operate and deliver power within or into the Region during the period of analysis in the assessment. Resources included in this category may be reported as a portion of the full capability of the resource, plant, or unit. This category includes, but is not limited to the following:

1. contracted (or firm) or other similar resource confirmed able to serve load during the period of analysis in the assessment;
2. where organized markets exist, designated market resource[43] that is eligible to bid into a market or has been designated as a firm network resource;
3. a Network Resource[44], as that term is used for FERC *pro forma* or other regulatory approved tariffs;
4. energy-only resources[45] confirmed able to serve load during the period of analysis in the assessment and will not be curtailed;[46]
5. capacity resources that cannot be sold elsewhere; and
6. other resources not included in the above categories that have been confirmed able to serve load and not to be curtailed[47] during the period of analysis in the assessment.

Existing, Certain & Net Firm Transactions — Existing, Certain capacity resources plus Firm Imports, minus Firm Exports. (MW)

Existing, Certain and Net Firm Transactions (%) (Margin Category) – Existing, Certain and Net Firm Transactions minus Net Internal Demand shown as a percent of Net Internal Demand.

Existing Generation Resources — *See* ***Existing, Certain, Existing, Other,*** and ***Existing, but Inoperable.***

Existing, Inoperable (Existing Generation Resources) — This category contains the existing portion of generation resources that are out-of-service and cannot be brought back into service to serve load during the period of analysis in the assessment. However, this category can include inoperable resources that could return to service at some point in the future. This value may vary for future seasons and can be reported as zero. This includes all existing generation not included in categories Existing, Certain or Existing, Other, but is not limited to, the following:

1. mothballed generation (that cannot be returned to service for the period of the assessment);
2. other existing but out-of-service generation (that cannot be returned to service for the period of the assessment);
3. does not include behind-the-meter generation or non-connected emergency generators that normally do not run; and
4. does not include partially dismantled units that are not forecasted to return to service.

Existing, Other (Existing Generation Resources) — Existing generation resources that may be available to operate and deliver power within or into the Region during the period of analysis in the assessment, but may be curtailed or interrupted at any time for various reasons. This category also includes portions of intermittent generation not included in Existing, Certain. This category includes, but is not limited to the following:

1. a resource with non-firm or other similar transmission arrangements;

[43] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[44] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[45] Energy Only Resources are generally generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources and may include generating capacity that can be delivered within the area but may be recallable to another area (Source: 2008 EIA 411 document OMB No. 1905-0129)." Note: Other than wind and solar energy, WECC does not have energy-only resources that are counted towards capacity.

[46] Energy only resources with transmission service constraints are to be considered in category Existing, Other.

[47] Energy only resources with transmission service constraints are to be considered in category Existing, Other.

2. energy-only resources that have been confirmed able to serve load for any reason during the period of analysis in the assessment, but may be curtailed for any reason;
3. mothballed generation (that may be returned to service for the period of the assessment);
4. portions of variable generation not counted in the Existing, Certain category (*e.g.*, wind, solar, etc. that may not be available or derated during the assessment period);
5. hydro generation not counted as Existing, Certain or derated; and
6. generation resources constrained for other reasons.

Expected (Transaction Category) — A category of Purchases/Imports and Sales/Exports with the following clarification:

1. Expected implies that a contract has not been executed, but is in negotiation, projected or other. These Purchases or Sales are expected to be firm.
2. Expected Purchases and Sales should be considered in the reliability assessments.

Firm (Transaction Category) — A category of Purchases/Imports and Sales/Exports with the following clarification contract including:

1. Firm implies a contract has been signed and may be recallable.
2. Firm Purchases and Sales should be reported in the reliability assessments. The purchasing entity should count such capacity in margin calculations. Care should be taken by both entities to appropriately report the generating capacity that is subject to such Firm contract.

Future Generation Resources (*See also* ***Future, Planned*** *and* ***Future, Other****)* — This category includes generation resources the reporting entity has a reasonable expectation of coming online during the period of the assessment. As such, to qualify in either of the Future categories, the resource must have achieved one or more of these milestones:

1. Construction has started.
2. Regulatory permits being approved, are any one of the following:
   a. site permit;
   b. construction permit; or
   c. Environmental permit.
3. Regulatory approval has been received to be in the rate base.
4. There is an approved power purchase agreement.
5. Resources is approved and/or designated as a resource by a market operator.

Future, Other (Future Generation Resources) — This category includes future generating resources that do not qualify in *Future, Planned* and are not included in the Conceptual category. This category includes, but is not limited to, generation resources during the period of analysis in the assessment that:

1. may be curtailed or interrupted at any time for any reason;
2. are energy-only resources that may not be able to serve load during the period of analysis in the assessment;
3. are variable generation not counted in the *Future, Planned* category or may not be available or is derated during the assessment period; or
4. is hydro generation not counted in category *Future, Planned* or derated.

Resources included in this category may be adjusted using a confidence factor to reflect uncertainties associated with siting, project development or queue position.

Future, Planned (Future Generation Resources) — Generation resources anticipated to be available to operate and deliver power within or into the Region during the period of analysis in the assessment. This category includes, but is not limited to, the following:

1. Contracted (or firm) or other similar resource;
2. Where organized markets exist, a designated market resource[48] that is eligible to bid into a market or has been designated as a firm network resource.
3. A Network Resource[49], as that term is used for FERC pro forma or other regulatory approved tariffs.
4. Energy-only resources confirmed able to serve load during the period of analysis in the assessment and will not be curtailed[50].
5. Where applicable, is included in an integrated resource plan under a regulatory environment that mandates resource adequacy requirements and the obligation to serve.

NERC Reference Reserve Margin Level (%) — Either the Target Reserve Margin provided by the Region/subregion or NERC assigned based on capacity mix (*e.g.*, thermal/hydro). Each Region/subregion may have their own specific margin level based on load, generation, and transmission characteristics as well as regulatory requirements. If provided in the data submittals, the Regional/subregional Target Reserve Margin level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigned a 15 percent Reserve Margin for predominately thermal systems and 10 percent for predominately hydro systems.

Net Internal Demand: Total Internal Demand reduced by the total Dispatchable, Controllable, Capacity Demand Response equaling the sum of Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak Pricing (CPP) with Control, and Load as a Capacity Resource.

On-Peak (Capacity**)** — The amount of capacity that is expected to be available on seasonal peak.

Potential Capacity Resources — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources, Conceptual Resources, and net provisional transactions minus all derates. (MW)

Potential Reserve Margin (%) — The sum of Deliverable Capacity Resources, Existing Other Resources, Future Other Resources, Conceptual Resources, and net provisional transactions minus all derates and Net Internal Demand shown as a percentage of Net Internal Demand.

Prospective Capacity Reserve Margin (%) — Prospective Capacity Resources minus Net Internal Demand shown as a percentage of Net Internal Demand.

Prospective Capacity Resources — Deliverable Capacity Resources plus Existing, Other capacity resources, minus all Existing, Other deratings (including derates from variable resources, energy only resources, scheduled outages for maintenance, and transmission-limited resources), plus Future, Other capacity resources (adjusted by a confidence factor), minus all Future, Other deratings. (MW)

Provisional (Transaction Category) — A category of Purchases/Imports and Sales/Exports contract including Purchases and Sales that are expected to be provisionally firm. Provisional implies

[48] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[49] Curtailable demand or load that is designated as a network resource or bid into a market is not included in this category, but rather must be subtracted from the appropriate category in the demand section.

[50] Energy only resources with transmission service constraints are to be considered in category Future, Other.

that the transactions are under study, but negotiations have not begun. Provisional Purchases and Sales should be considered in the reliability assessments.

Reference Reserve Margin Level — *See* ***NERC Reference Reserve Margin Level***

Reserve Margin (%) —Roughly, Capacity minus Demand, divided by Demand or (Capacity-Demand)/Demand. Replaced *Capacity Margin(s) (%)* for NERC Assessments in 2009.

Target Reserve Margin (%) — Established target for Reserve Margin by the Region or subregion. Not all Regions report a Target Reserve Margin. The NERC Reference Reserve Margin Level is used in those cases where a Target Reserve Margin is not provided.

Transfer/Transaction (*See also* ***Firm, Non-Firm, Expected*** *and* ***Provisional)*** **—** Contracts for Capacity are defined as an agreement between two or more parties for the Purchase and Sale of generating capacity. Purchase contracts refer to imported capacity that is transmitted from an outside Region or subregion to the reporting Region or subregion. Sales contracts refer to exported capacity that is transmitted from the reporting Region or subregion to an outside Region or subregion. For example, if a resource subject to a contract is located in one Region and sold to another Region, the Region in which the resource is located reports the capacity of the resource and reports the sale of such capacity that is being sold to the outside Region. The purchasing Region reports such capacity as a purchase, but does not report the capacity of such resource. Transmission must be available for all reported Purchases and Sales.

Abbreviations Used in This Report

316(b)	Clean Water Act – Section 316(b), Cooling Water Intake Structures
APCR	Adjusted Potential Capacity Resources
AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (subregion of WECC)
BTA	Best Technology Available
CA	California (subregion of WECC)
CA-MX-US	California-México (subregion of WECC)
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCB	Coal Combustion Byproducts
CCR	Coal Combustion Residuals
DOE	U.S. Department of Energy
EIA	Energy Information Agency (of DOE)
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EVA	Energy Venture Associates
FERC	U.S. Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
gpm	Gallons per minute
GW	Gigawatt
GWh	Gigawatt hours
HACI	Halide-treated Activated Carbon Injection
HAP	Hazardous Air Pollutants
MACT	Maximum Achievable Control Technology
mgd	Million gallons per day
MRO	Midwest Reliability Organization
MW	Megawatts (millions of watts)
MWH	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NESHAP	National Emissions Standards of Hazardous Air Pollutants
NO_x	Nitrogen Oxide
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (subregion of WECC)
NYPP	New York Power Pool
PV	Photovoltaic
RCRA	Resource Conservation Recovery Act
RFC	Reliability*First* Corporation
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RMRG	Rocky Mountain Reserve Group
RP	Reliability Planner
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
tpy	Tons per year
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
WECC	Western Electricity Coordinating Council

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to ensure

the **reliability** of the

bulk power system