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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

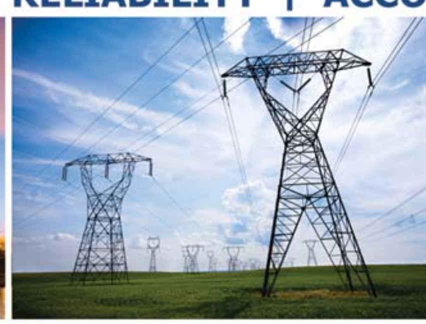
Potential Impacts of Future Environmental Regulations

Extracted from the 2011 Long-Term Reliability Assessment

November 2011

RELIABILITY | ACCOUNTABILITY






NOTICE: This document includes the Assessment Area sections originally included in the "2011 Long-Term Reliability Assessment" (http://www.nerc.com/files/2011LTRA_Final.pdf), and is not intended to be a standalone report.

Potential Impacts of Future Environmental Regulations

Summary

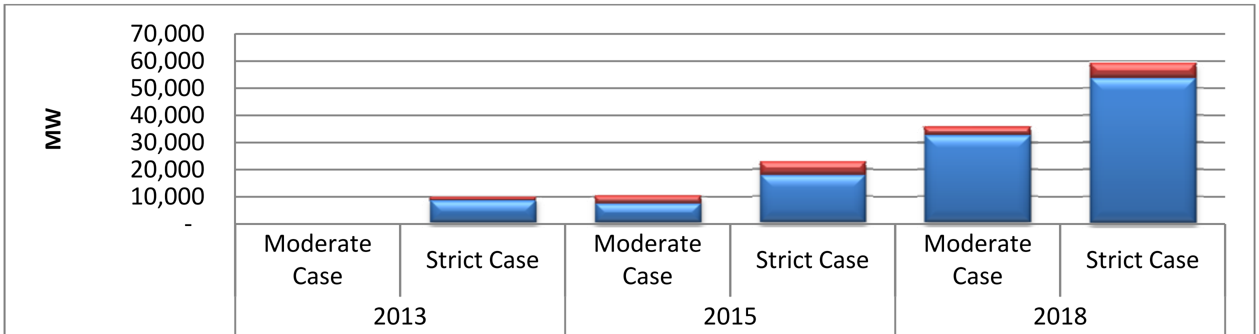
In the United States (U.S.), the Environmental Protection Agency (EPA) is in the process of promulgating four regulations: the proposed Coal Combustion Residuals rule (CCR rule), the proposed Mercury and Air Toxics Standards for Utilities, (Utility Air Toxics rule) the proposed Cooling Water Intake Structures § 316(b) rule (316(b) rule) , and the final Cross-State Air Pollution Rule (CSAPR).[119] In October 2010, NERC released an assessment of the potential resource adequacy effects of precursors to these proposed rules using 2009 bulk power system resource plan projections and demand forecasts. This 2010 assessment, entitled: *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (2010 NERC EPA Assessment), provided an independent and integrated preliminary perspective on the potential for the accelerated retirement of fossil-fired units under assumptions based on earlier versions of the rules or expectations about what the rules would contain.

While it is not possible to determine the exact impacts of these regulations until each regulation is finalized, many studies have been performed which attempt to predict the effects of these regulations as well as other economic factors driving retirements of electric generating units. This assessment, which is included as a companion study in this *2011 Long-Term Reliability Assessment*, updates the resource and demand forecasts used in the 2010 NERC EPA Assessment with the 2011 forecasts. Additionally, NERC revised the assumptions applied in its 2010 NERC EPA Assessment, taking into account new information that was not available at the time that report was prepared. Specifically, in this update, NERC used updated assumptions determined from proposed rules, as well as other viewpoints on how the rule will ultimately be carried out (*i.e.,* how states may implement regulations), to determine potential resource adequacy impacts. The expected retirements of electric generators are driven by many economic factors, not simply the cost of pollution control equipment.

While these updated results are provided for informational purposes to inform stakeholders and policy makers, they do not represent NERC's judgment on which units can, should, or will be retired. The two cases assessed are based on scenarios that represent a range of potential outcomes. Based on the results of the Moderate Case, 36 GW of incremental capacity in coal, oil, and gas-fired generation is identified for either retirement or for capacity reductions to support additional station loads (deratings) by 2018 (Figure 54). In the Strict Case, capacity reductions amount to approximately 59 GW. Of most important, however, are the retirements that may occur, as well as the retrofits that need to be implemented, by 2015, which are primarily driven by compliance deadlines in the proposed Utility Air Toxics rule.

[119] EPA promulgated the Final CSAPR on August 8, 2011 establishing a Federal Implementation Plan requiring 27 states to reduce power plant emissions of sulfur dioxide and nitrogen oxides that cross state lines and contribute to ozone and particulate pollution in other states. However, on October 14, 2011 EPA proposed technical revisions to the August 8th final rule, which are not yet finalized.

Figure 54: Incremental Capacity Reductions Due to the Combined EPA Regulation Scenario



	Moderate Case 2013	Strict Case 2013	Moderate Case 2015	Strict Case 2015	Moderate Case 2018	Strict Case 2018
Derate (MW)	-	1,217	2,770	4,996	3,174	5,584
Retired (MW)	-	8,574	7,491	17,844	32,589	53,574

This update concludes, however, that of these four rules, the 316(b) rule will have the greatest impact on the amount of capacity that may be economically vulnerable to retirement (approximately 25 to 39 GW) and, consequently, the greatest impact on Planning Reserve Margins, (Figure 55).

Figure 55: Incremental Capacity Reductions Due to Individual Rules

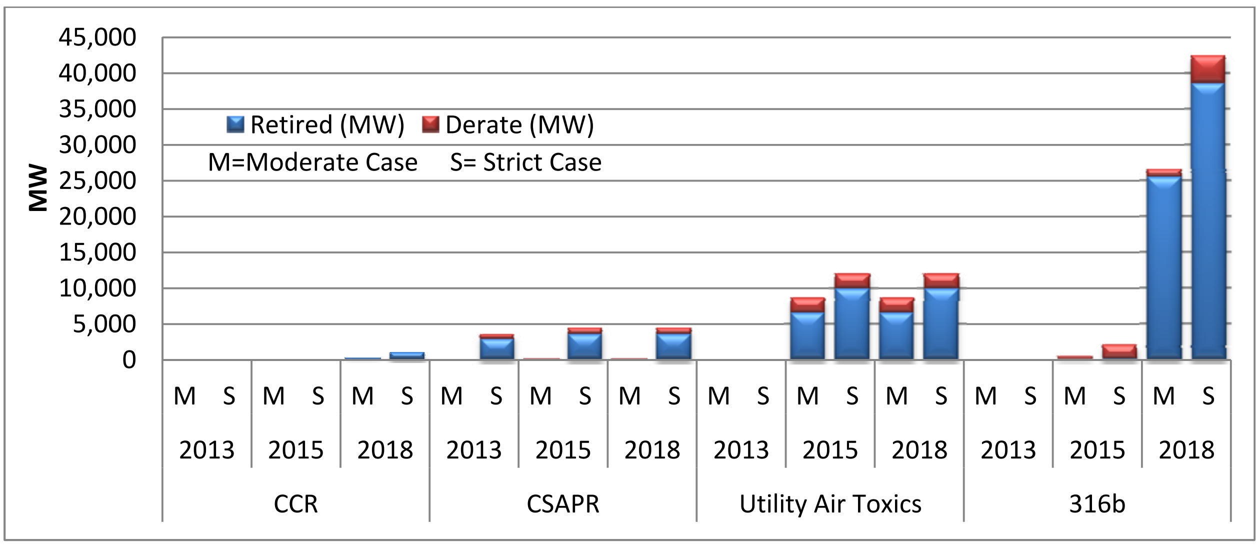


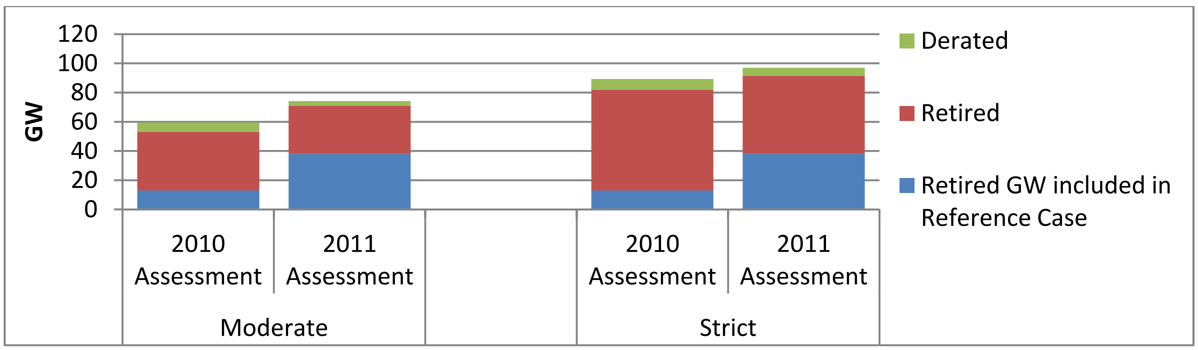
Figure 55, shows the respective rules' individual effects on retirements and derates. As the chart indicates, retirements or derates are not expected in 2013 under the Moderate Case. For the Strict Case, three of the four rules are not expected to cause any retirements or derates, and CSAPR is estimated to impact about 3.5 GW. In 2015, in the Moderate Case, CCR has no impact and the 316(b) rule impacts less than 1 GW due to their assumed compliance dates occurring beyond 2015. For 2015, the Utility Air Toxics rule alone would impact about 9 GW, in the Moderate Case, and could increase to about 12 GW, in the Strict Case.

When compared to the 2010 assessment, the results of this update show a net increase in the amount of potential decreases that can be expected by 2018 (Figure 56). While the potential impacts of

compliance with EPA regulations presented in this update are less than those in the 2010 NERC EPA Assessment, a total of approximately 38 GW of generation capacity (23 GW of coal and 15 GW of gas/oil units) have already committed and/or announced plans to retire. While these generating units most likely announced plans to retire for a variety of reasons, a majority of these units were identified in the 2010 NERC EPA Assessment as economically vulnerable.

These retirement announcements and commitments have decreased the amount of assessed capacity in the study baseline and narrowed the capacity for which compliance plans must be projected. In the 2010 NERC EPA Assessment, the amount of retirement announcements was 13 GW; 25 GW less than in this update. These plant retirements have already been considered in the Regional assessments and the reductions included in the 2011 LTRA Reference Case.

Figure 56: Comparison of Projected 2018 Capacity Reductions between 2010 and 2011 Study Results



For this update, 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. If no action is taken to replace existing resources, signs of not meeting resource adequacy requirements appear to be most prevalent in the ERCOT Region. In ERCOT, the Anticipated Planning Reserve Margin falls below the NERC Reference Margin in 2013 (Figure 57); 2015 when considering Adjusted Potential Resources.

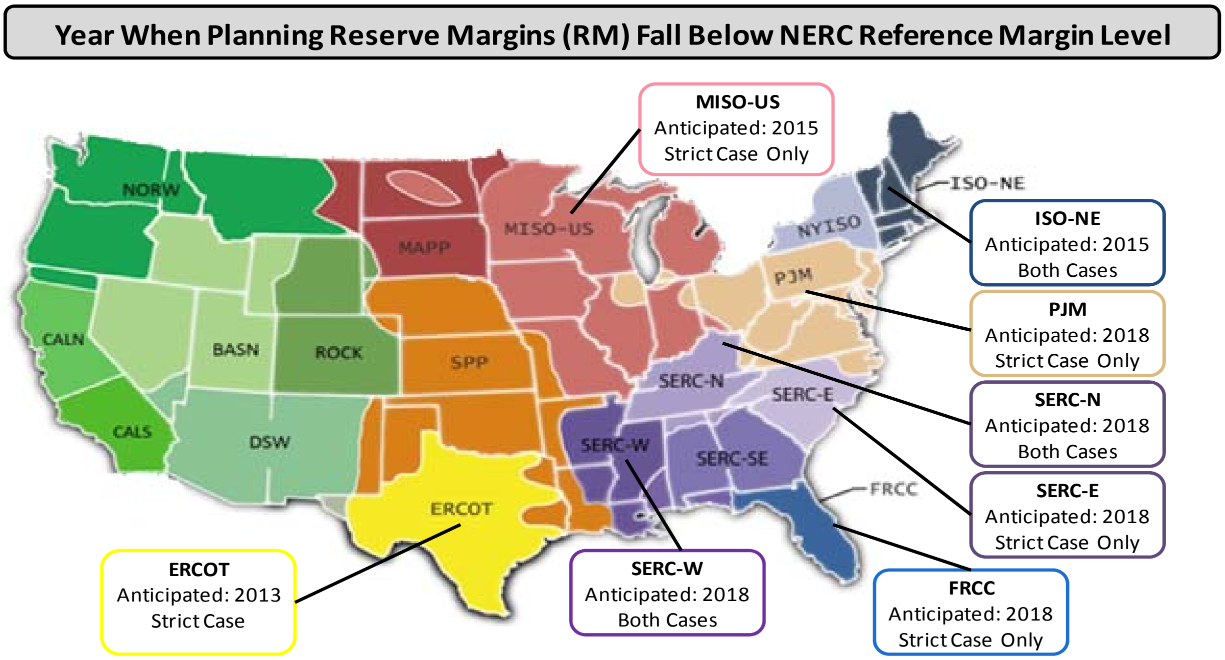
MISO and NPCC-New England show decreased Planning Reserve Margins below the NERC Reference Margin Level by 2015—FRCC, PJM, SERC-E, SERC-N, and SERC-W by 2018. These areas may need more resources than are currently planned in this assessment.

For some Assessment Areas, Planning Reserve Margins are below the NERC Reference Margin Level in the Reference Case as well. In these Assessment Areas, concerns even without applying scenario assumptions may exist. For example, in the 2011 Reference Case, the ERCOT and NPCC-New England Anticipated Planning Reserve Margins fall below the NERC Reference Margin Level in 2014 and 2015, respectively.

The impact on Planning Reserve Margins will be dependent on whether sufficient replacement capacity (or other system reinforcements) can be added in a timely manner to replace the generation capacity that is retired or lost. Unless additional resources are developed in certain Assessment Areas, beyond what is planned in the 2011 Reference Case, or additional time is provided to units needed to maintain

Planning Reserve Margins, bulk power system reliability could be affected. Implementation must allow sufficient time to construct new, or retrofit existing capacity, and allow the system to be planned and operated in accordance with NERC Reliability Standards and Regional Criteria at all times. Therefore, the timing of the rules must also consider the time needed for the industry to make incremental transmission upgrades and perform any other system reconfigurations that may be needed to maintain reliability. Additional time considerations should be made for the compliance period—the time period following the finalization of any particular rule.

Figure 57: Assessment Areas with Potential Resource Adequacy Issues



A significant retrofit effort is expected over the next ten years in order to comply with proposed EPA regulations. Environmental controls are expected to be put in place to meet air regulations by the end of 2015. In total, between 576 and 677 coal-fired unit retrofits (Moderate and Strict Case, respectively) will be needed by the end of 2015, totaling 234 to 258 GW of retrofitted coal capacity. Constricted compliance deadlines may challenge the electric industry's planning horizons, existing planning processes and typical construction schedules. Successful implementation of environmental regulations will be highly dependent on the ability of units needed for reliability to obtain the necessary time needed to comply with certain requirements. Given the timelines for compliance, many of the affected units may need to take maintenance outages concurrently. The need to take multiple units out-of-service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns during maintenance periods.

As discussed in the *Emerging and Standing Reliability Issues* section of this report, NERC identifies a number of tools the industry has available to mitigate potential reliability impacts from the implementation of EPA regulations. NERC's expectation is that industry and regulators will use these tools to ensure that bulk power system reliability is maintained as EPA regulations are finalized and implemented.

Recommendations

The following recommendations are pertinent to Federal and state regulators, the electric industry, as well as NERC, and supplement the 2010 NERC EPA Assessment:

Regulators:

- The Electric Reliability Organization's Reliability Standards and Regional Criteria must be met at all times to ensure reliable operation and planning of the bulk power system. Based on the results of this study, more time is needed in certain areas to ensure resource adequacy and local reliability requirements can be addressed during the transition and compliance period. EPA, FERC, DOE, and state utility regulators, working together and separately, should employ the array of tools at their disposal and their regulatory authority to preserve bulk power system reliability, including the deferral of compliance targets and granting extensions where there is a demonstrated reliability need. Coordination among Federal agencies is necessary to ensure the industry is not forced to violate one regulation to meet another.

Industry:

- Industry participants must meet NERC's Reliability Standards to ensure reliability and as they address compliance requirements of the EPA regulations. They should employ available tools and processes to ensure that bulk power system reliability is maintained through any resource transition. Toward that end, regional wholesale competitive market operators should ensure capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in areas without organized markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations. Additionally, affected unit owners that may be disconnected from wide-area planning functions (*e.g.,* generator owners operating in an ISO/RTO), should provide Planning Authorities timely and accurate information about the compliance plans for their units in order to adequately measure.

- Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed environmental control equipment. Outages for retrofits, new generation, and required transmission must be coordinated to ensure continued bulk power system reliability not only during peak periods, but during off-peak shoulder months when more scheduled outages are expected to occur.

NERC:

- NERC should continue to assess the implications of the EPA regulations as greater certainty emerges around industry obligations, technologies, timelines, and targets. Further, NERC should lead industry's effort and response to measure resource adequacy implications along with impacts to operating reliability (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) resulting from proposed and pending EPA regulations. NERC should leverage the expertise of the Planning Authorities to assess the local system conditions that could degrade reliability, review plans for meeting environmental regulations as well as NERC Reliability Standards, and submit recommendations to FERC on behalf of the industry.

Introduction

Future environmental requirements will have direct impacts on power supply decisions and grid reliability. The EPA is currently developing rules under its existing regulatory authority that could potentially require existing power suppliers to invest in retrofitting environmental controls at their existing units, or accelerate their retirement. NERC issued the *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (2010 NERC EPA Assessment) in October 2010 to address these concerns.[120] Since then, the EPA has issued proposed rules for Utility Air Toxics and 316(b) (impingement and entrainment of aquatic organisms), and finalized -CSAPR.[121] The 2010 NERC EPA Assessment recommended continued monitoring of pending EPA regulations, as greater certainty emerged regarding industry obligations, technologies, timelines, and targets.

Based on events that have occurred since the initial report was released, NERC has revised the 2010 modeling to reflect updated assumptions, with additional consideration for new information received from the industry. Building on the 2010 NERC EPA Assessment, this update compares resource plans provided by Regional Entities and Planning Authorities throughout the U.S. The differential will be granular, with a special focus on the Planning Reserve Margin impacts for each Assessment Area within the U.S. Differences will be measured to identify potential uncertainties in resource plans, and to better understand what decisions are yet to be made by NERC's stakeholders to address EPA's rulemaking.

Since publication of the initial report, the following material changes have occurred regarding the environmental regulation landscape in the U.S.:

- EPA proposed the Utility Air Toxics rule that includes limits on emissions of hazardous air toxics: particulate matter (PM) as a surrogate for non-metals, acid gases in the form of hydrogen chloride (HCl), and mercury. The Clean Air Act requires compliance with air toxics regulations within 3 years of a final rule, with extensions permitted under certain circumstances. Although extensions may be possible under the Clean Air Act, there is no guarantee they will be granted. It will be uneconomic for some units to retrofit to comply with the Utility Air Toxics rule and thus some units are expected to retire. Additionally, units being retrofitted with necessary controls may be unavailable for some time if retrofits cannot be completed prior to the compliance deadline.

- EPA proposed a Section 316(b) rule that includes implementation options that differ from those assumed in the 2010 NERC EPA Assessment. In the 2010 NERC EPA Assessment, cooling towers were assumed to be required in order to comply with the rule. The currently proposed rule, which includes separate impingement and entrainment requirements, may permit the applicability of modified technologies such as traveling screens for compliance with the

[120] http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf

[121] EPA promulgated the Final Cross-State Air Pollution Rule on August 8, 2011 establishing a Federal Implementation Plan requiring 27 states to
reduce power plant emissions of sulfur dioxide and nitrogen oxides that cross state lines and contribute to ozone and particulate pollution in other states. However, on October 14, 2011 EPA proposed technical revisions to the August 8th final rule, which are not yet finalized.

impingement standard. However, the proposed rule would also require site specific entrainment studies, which would ultimately leave the final determination of compliance alternatives to each state. It is unknown how many facilities will be able to comply with the proposed rule without cooling towers.

- As a total replacement to the existing Clean Air Interstate Rule (CAIR), the proposed Clean Air Transport Rule (CATR) has been finalized with a variety of different requirements, titled the Cross-State Air Pollution Rule (CSAPR), including the addition of the state of Texas to the program. For this analysis, the rule does not allow the use of existing banked allowances for compliance and requires compliance with only limited trading without penalties starting in 2012.[122]

- Forecast demand and resource plans for the 2011-2021 assessment timeframe have significantly changed, directly affecting the Planning Reserve Margin projections.

- This update did not measure timelines for retrofitting to install needed environmental equipment, as this scheduling optimization is part of operational reliability. However, a large area view will be needed (potentially throughout the interconnections) for this schedule outage timing, to ensure sufficient operational reliability can be maintained while supporting bulk power system reliability.

These considerations and the potential reliability implications they pose to the industry have triggered a need for NERC to update the results of the 2010 NERC EPA Assessment, measuring the incremental implications resulting from these four EPA regulations (the proposed CCR Rule, proposed Utility Air Toxics Rule, proposed 316(b) Rule, and the final CSAPR). Additional rules that are not addressed but that may also impact assumptions would include the existing and expected Greenhouse Gas (GHG) requirements for new, modified, and existing sources, the Clean Air Visibility Rule (CAVR), and more stringent air quality standards.

Overall impacts on Planning Reserve Margins across the U.S. are assessed and areas below the NERC Reference Margin Level are identified. While the NERC analysis primarily focuses on the cumulative impacts of the four regulations, the impacts of each individual rule is also provided. These four regulations, plus other pending CO_2 regulations in the United States, are expected to go into effect on a staggered basis over the next ten years.

[122] This analysis does not consider the recent changes to CSAPR proposed by EPA, which would increase several state budgets and provide increased compliance flexibility. Proposed revisions to the rule are now being considered by the EPA: http://www.epa.gov/crossstaterule/techinfo.html

Background

In the U.S., several regulations are being promulgated by the EPA. Depending on the outcome of any or all of these regulations, the cost of compliance may result in early retirement of some fossil fuel-fired power plants. This update is designed to examine the potential reliability impacts, specifically concerning Planning Reserve Margins, from these environmental regulations.[123] The four regulations reviewed in this update are:

1) Clean Water Act – Section 316(b), Cooling-Water Intake Structures (316(b) rule)
2) Coal Combustion Residuals (CCR)
3) Cross-State Air Pollution Rule (CSAPR)
4) Title I, Clean Air Act –MACT –(Utility Air Toxics Rule)

Determinations on the cost of compliance were based on assumptions regarding potential regulations that have not been finalized by the EPA.[124] Ultimately, generation owners will determine the costs of compliance and make decisions about investments versus unit retirements; however, assumptions were intented to help stakeholders understand the potential impacts of these regulations.[125]

The 2010 NERC EPA Assessment examined the potential system resource adequacy impacts of these same four pending EPA regulations. This update estimated the future program requirements and the compliance measures that these four EPA rules would ultimately require. For two programs (CSAPR, CCR), the assessment was based upon draft regulations that had been issued during the summer of 2010. However, for the two other programs (316(b) and Utility Air Toxics), EPA had not yet developed draft regulations. For these two programs, the assessment was built upon extensive discussions of the possible program provisions with industry representatives, as EPA could not discuss their impending draft rules still under development.

Since the release of the 2010 NERC EPA Assessment, EPA has finalized one program rule (July 2011 C CSAPR, formerly proposed as the Clean Air Transport Rule). However, this rule is subject to revisions proposed by the EPA in October 2011. EPA has also issued draft rules for public comment for two pending programs—316 (b) Cooling Water Intake Structures (March 2011) and Utility Air Toxics Rule (May 2011). These revisions are sufficiently different from the 2010 estimates and this update reflects these program changes.

In addition, other market changes have occurred after the 2010 NERC EPA Assessment that have significant impacts on grid reliability. For example, demand forecasts for the period have been updated to 2011 projections. In some Regions, the demand forecasts have increased at a faster growth rate than prior projections, further reducing projected reserve margins. In addition, more generator owners have

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[123] Analysis performed by Energy Ventures Analysis, Inc. (http://www.evainc.com/) for NERC in September 2011 serves as the basis for this report.

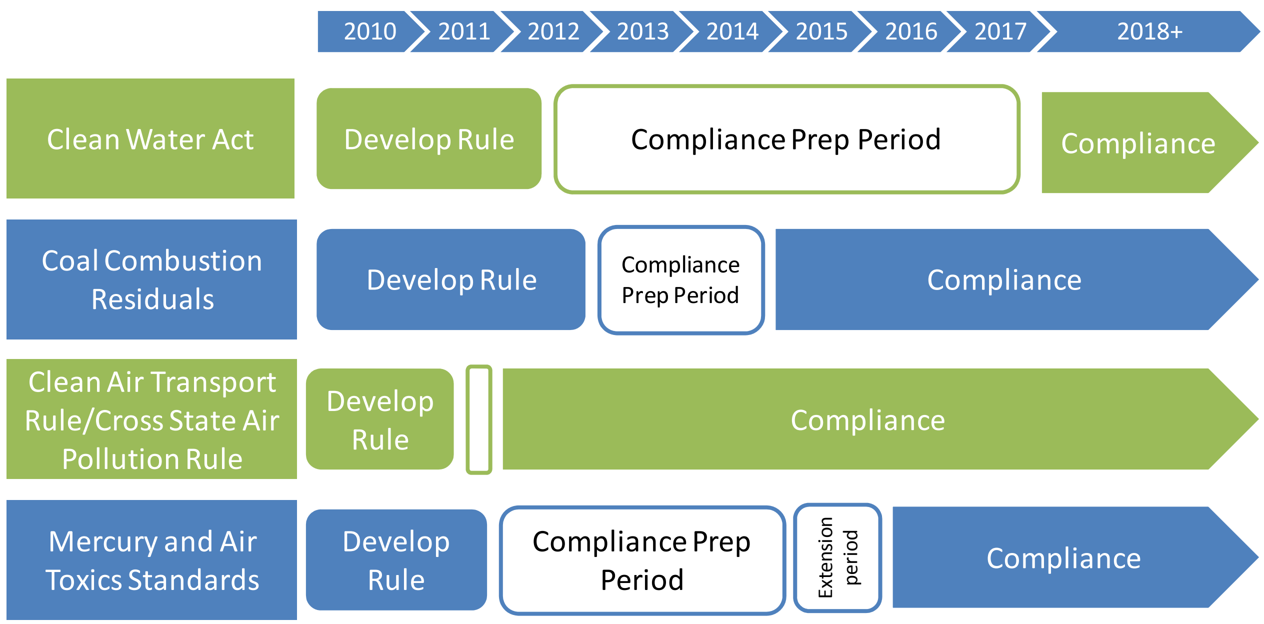
[124] Assumptions for Clean Water Act – Section 316(b), Cooling-Water Intake Structures, Coal Combustion Residuals (CCR), and Utility Air Toxics Rule were applied. The finalized Cross-State Air Pollution Rule (CSAPR) requirements were included in this analysis, but do not reflect the proposed changes to the Rule that EPA released in October 2011.

[125] The material in this report is provided for informational purposes and is not intended to reflect NERC's opinion on which units can, should, or will be retired—it is a scenario that reflects potential outcomes.

announced their unit retirement plans. These retirement announcements have decreased the available capacity in the study baseline and narrowed the capacity for which compliance plans must be projected. Not surprisingly, most of the announced capacity retirements to date had been projected to retire within the results of the 2010 NERC EPA Assessment. However, there have also been some that were not projected to retire that have been announced since then.

A high-level timetable of rule implementation and compliance deadlines is presented below (Figure 58). In general, short compliance timelines can stress the bulk power system if requirements cannot be met by the compliance date. However, given a timeline that accommodates retrofit construction times and time to build or acquire additional resources, which may or may not include upgrades to the transmission system, both reliability and environmental goals can be met.

Figure 58: Projected Timeline for Regulation Development and Implementation

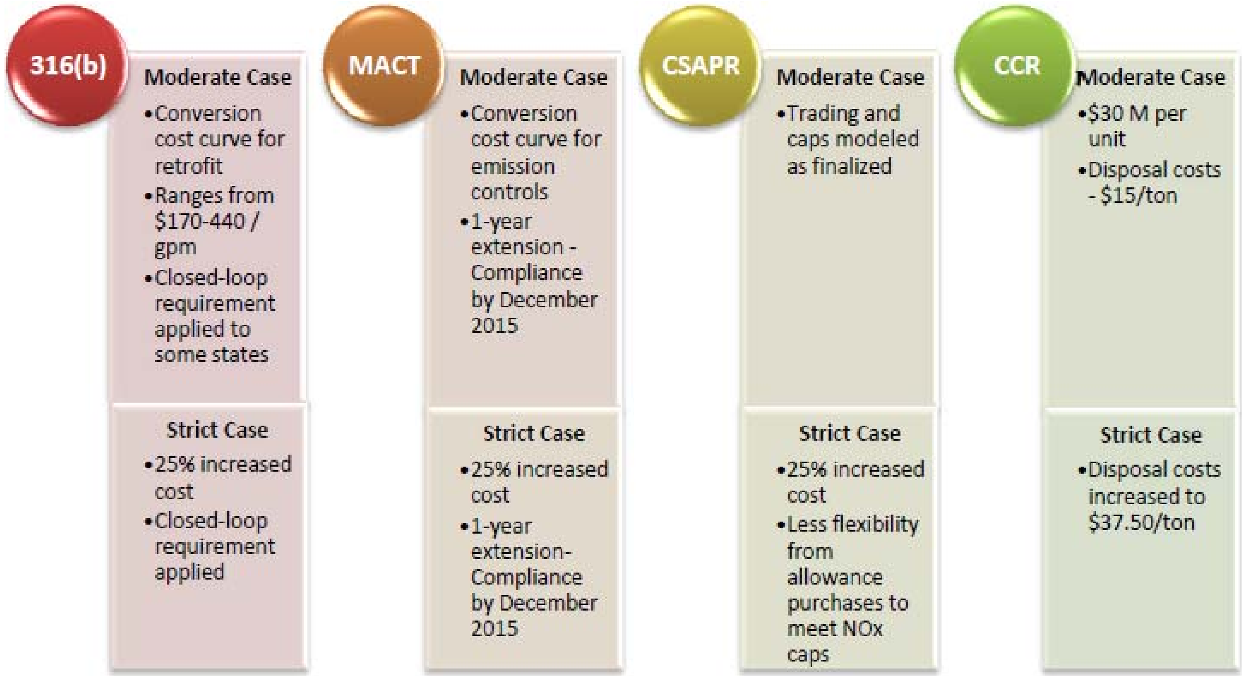


Reliability Assessment Study Design

This update focused on measuring the potential resource implications of the cumulative impact of the four proposed regulations and also seeks to identify cases where additional resources, beyond what is planned for in the 2011 Reference Case, may be required. The study objectives are as follows:

1. Identify and estimate potential future outcomes of four EPA rules.
2. Develop two cases (Moderate and Strict) to quantify the range of potential unit retirement risk from the aggregated impacts for 2013, 2015 and 2018
3. Examine the impacts of the unit retirement on Planning Reserve Margin (by Assessment Area)

Figure 59: Differences in Moderate and Strict Scenario Cases



Summary of Assumptions Used in This Report

The general approach used in this study assumes that there are only two choices to consider when complying with the new EPA regulations:

1. Retrofit the generating unit and continue operating;
2. Retire the generating unit and replace it with a greenfield natural gas unit

A more detailed discussion of this approach is included in the 2010 NERC EPA Assessment.[126]

This update does not provide consideration for the additional impacts of future greenhouse gas (GHG) control legislation, other state environmental control measures, national renewable portfolio standards (RPS), or other potential environmental rules and regulations.

This update also excludes any consideration of CO_2 legislation, and also assumes that there is no risk of future CO_2 legislation that will impact industry investment decisions. However, industry should consider the additional impacts from this type of legislation when making plant investment decisions. Depending on how power suppliers quantify these risks, unit retirements could result beyond those projected in this assessment.

Additional assumptions employed in this reliability assessment are as follows:

[126] http://www.nerc.com/files/EPA_Scenario_Final_v2.pdf
Using a different retirement method may produce different results. For instance, assessing merchant generation on future asset performance may potentially increase the amount of economically vulnerable capacity of retirement depending on the model input assumptions, if economics are unprofitable.

- Plant retirements already committed or announced (37.63 GW) are excluded. These retirement announcements and commitments have decreased the available capacity in the study baseline and narrowed the capacity for which compliance plans must be projected. These plant retirements are already included in the 2011 LTRA Reference Case. Information and data on the 2011 LTRA Reference Case can be found in this report, with summarized data included in the *Estimated Demand, Resources, and Reserve Margin* section. Incremental capacity losses are assessed in this scenario.

- Assessment of the ability of the industry to permit, engineer, finance and build the required environmental controls within the required compliance timeframe was not included. However, implementation will place demands on the equipment and construction sectors since multiple EPA programs will be phased-in over the same timeframe. This situation is compounded by a significant number of electric generation units that are likely to retrofit environmental controls, and there will be competition created by replacement generation capacity projects and other heavy U.S. infrastructure projects in other sectors. Costs could escalate beyond the assumed compliance costs, should the EPA require compliance within three years of the final rulemaking dates. Therefore, the Strict Case includes an increase of 25 percent for the required control equipment.

- Compliance costs (*i.e.,* capital, O&M and performance changes) are based upon current average retrofit costs with existing technology market conditions. As noted above, the update does not assess any compliance cost risk impact caused by a run-up in labor and material from a large construction boom of environmental control and replacement power projects. By applying average retrofit control costs by size in lieu of a detail, site-specific engineering study, capital retrofit costs may over-or under estimate the cost at the site specific level.

- Increased CCR disposal costs can vary widely based upon site land availability, geology and state disposal permit requirements. An EPA assumption of onsite disposal is adopted, and the calculated disposal costs are similar to those employed in this update. However, if onsite disposal is prohibited (*i.e.,* land constraints, poor geology, etc.), the plant would incur additional costs to transport the ash and residuals to a properly permitted landfill, as well as tipping fees. These costs could be significant, but cannot be estimated without a site-specific analysis. For these reasons, sensitivity analysis is also performed for CCR disposal costs.

- Power suppliers will need to bring their units offline to tie in their retrofit environmental controls. During these periods, suppliers will lose potential revenues and may need to procure higher cost replacement power. While the capital and O&M costs are incorporated into the compliance decision, the replacement purchased power costs have not been included. These replacement costs are unlikely to change or accelerate unit retirement decisions, but would have the greatest effect on the nuclear plants that would incur the largest replacement power costs.

- For retrofit of once-through water cooling units, all nuclear plants are assumed to either become exempted, be subject to alternative investments, or else will be able to make the required investments. Therefore, no nuclear retirements are assumed in this update. This assessment does

not include any derate effects for nuclear capacity from Section 316(b). However, the maximum loss of capacity due to derates of nuclear plants is estimated to be about 1.8 GW U.S.-wide.

- Under its draft Section 316(b) regulations, EPA left the authority to set fish entrainment standards (which are the regulatory driver for closed cycle cooling) to state regulators. With lack of a specific defined standard, compliance measures could range from low cost screens to very expensive recirculating cooling water systems. While state regulators have some flexibility in setting standards and can take reliability impacts into consideration, regulators are to use standards based upon recirculating cooling water systems as their default standard. For this update, an assessment of the states' past regulatory actions and current policies concerning closed cycle cooling were reviewed. The Moderate Case assumes that only states with "more-aggressive" water supply policies (accounting for 75 percent of affected capacity) would require recirculating water systems. In the Strict Case, all plants would require recirculating cooling water systems.[127] While closed cycle cooling is one of the options that states will consider under the guidelines required by the EPA, the proposed rule does not mandate closed cycle cooling. Given its large potential compliance cost and impact, this assumption may have the single largest impact in terms of the amount of capacity that may be economically vulnerable.

- In practice, generating units identified in this update as economically vulnerable may choose to wait until immediately prior to the compliance deadline before closing the generation unit. This ability to delay retirement may tend to act as a binary option with the effect that many units would retire on December 31 prior to a January 1 deadline.

- All combined cycle plants are assumed to make required investments and not be forced into early retirement. This may not be the case. For Utility Air Toxics, oil power stations are assumed to meet emission limits through availability of suitable quality specifications of refined oil products.

- This update excludes any fossil fuel market price or supply risks 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. Also, plant owners may decide to invest in brownfield construction after retirement. Such analysis is beyond the scope of this update.

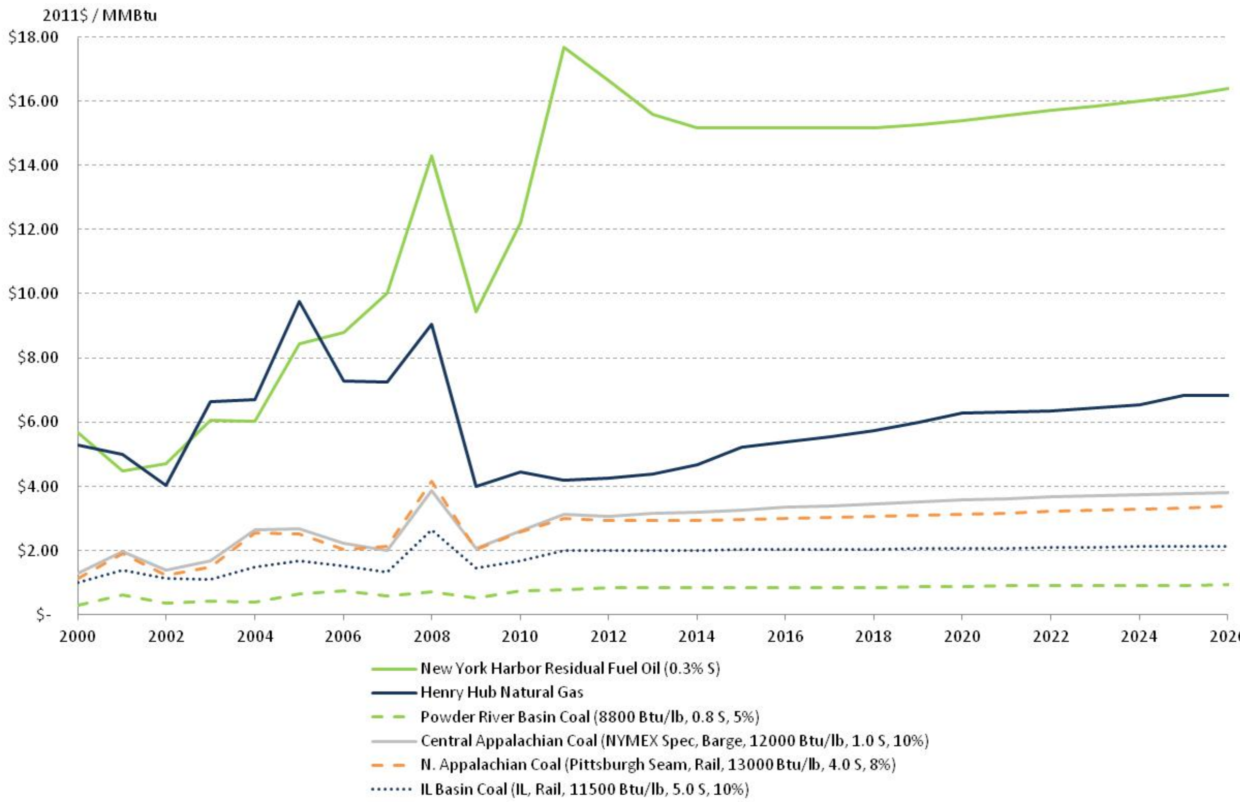
- Local reliability issues resulting from individual unit retirements were not studied. Operational reliability impacts, such as generation deliverability or stability, were not analyzed by NERC. For example, transmission system construction, enhancements, reconfiguration and development of

[127] While the requirement of mandating cooling towers for all open-loop cooled units is not explicitly noted in the proposed EPA rule and has a low likelihood of materializing, these assumptions provide a full spectrum of potential outcomes.

new operating procedures may be necessary in some areas, all of which can create additional timing considerations. However, some Regions and stakeholders within those Regions have assessed these concerns, and a summary of their findings are included in the *Regional Update* section.

- Delivered natural gas, coal and oil prices were based on the forecasts of Energy Ventures Analysis (EVA) as of October 2011. Ten-year forward averages are applied for 2013, 2015 and 2018. Varying these price assumptions may produce different results. The wholesale fuel price forecasts on an undelivered basis are depicted below (Figure 60). A sensitivity analysis to changes in natural gas commodity prices is presented in this update.

Figure 60: EVA Wholesale Wellhead Gas Price Forecasts

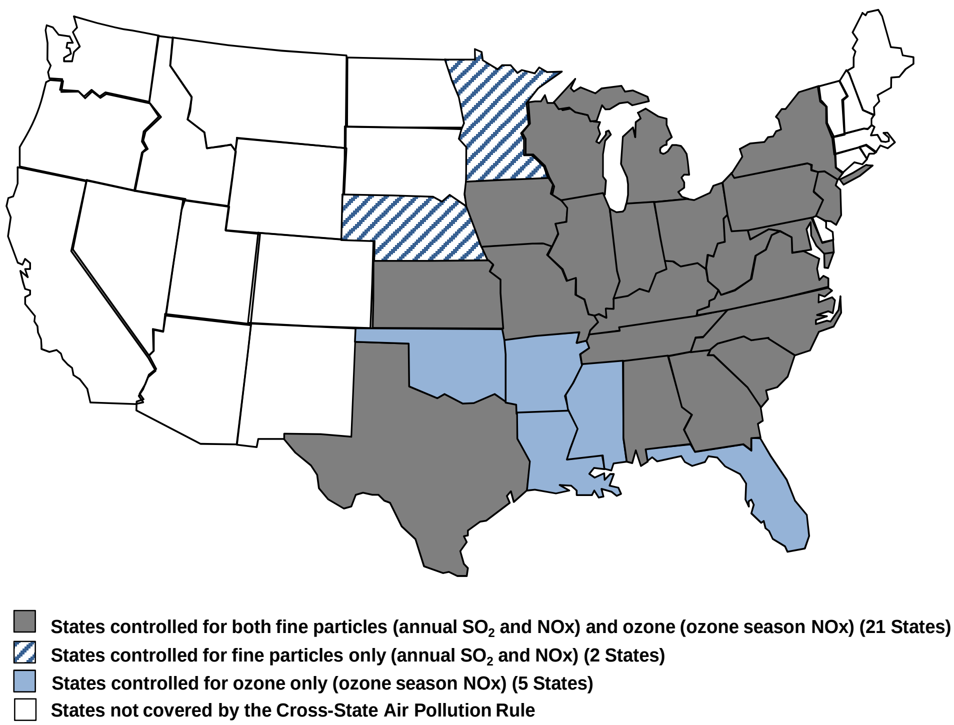


Current Status of EPA Regulations and Expected Outcomes

Cross-State Air Pollution Rule (CSAPR)

The EPA published its final CSAPR regulations on July 6, 2011, followed by the publication of proposed "technical corrections" in early October 2011. This rule was authorized under the 1990 Clean Air Act Amendments to address long-range transport of pollutants contributing to downwind non-attainment of fine particulate and ozone National Ambient Air Quality Standards. The EPA final rule creates three new pollutant cap and trade programs (SO_2, annual NO_X and seasonal NO_X) that will affect fossil fuel sources across a twenty-eight state region (Figure 61). Nearly 91 percent (259,603 MW) of the existing coal-fired capacity (excluding announced retirement plans) are located within this affected region. The first phase of CSAPR program will take effect on January 1, 2012 and targets an additional reduction in some state SO_2 emission budgets in 2014.

Figure 61: CSAPR State Programs

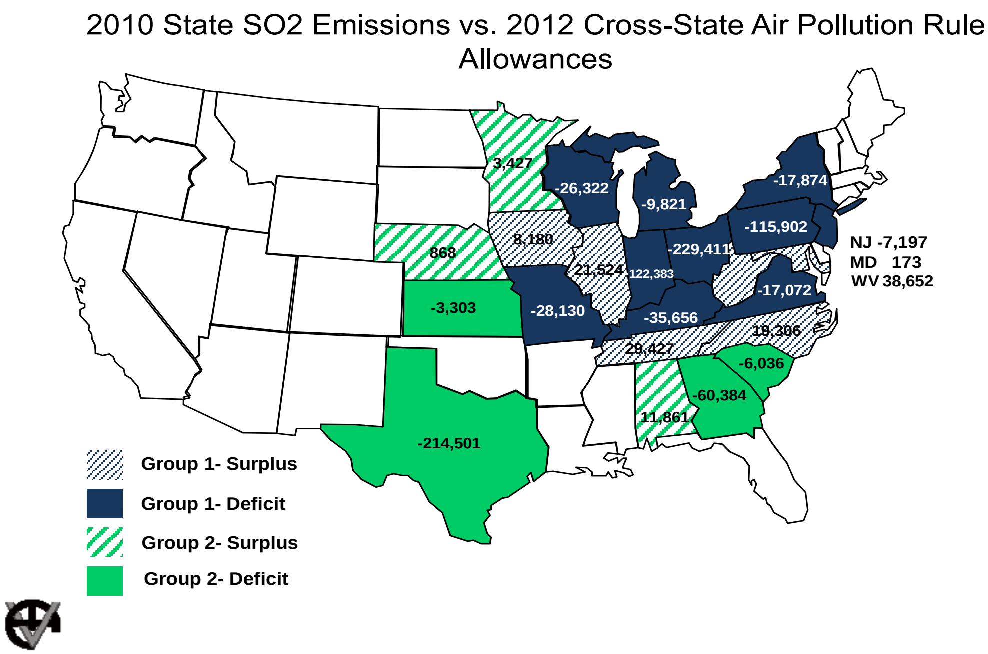


The additional emission reductions needed to comply are significant and highly concentrated to a few states (Figure 62). The constricted implementation period limits the available unit compliance options for meeting the 2012 emission caps. Companies are unable to permit and implement additional retrofit environmental control measures within 24-36 months, unless the construction phase has already commenced. Upgrades of existing flue gas desulphurization (FGD) equipment to enhance the performance of SO_2 removal and/or boiler upgrades enabling switching to lower sulfur fuels, will also take more than one year to engineer, permit, finance and implement. Insufficient time to retrofit units

with necessary environmental controls[128] combined the anticipated initial shortage of surplus allowances offered for sale will potentially leave companies with limited options to satisfy compliance requirements by 2012. The remaining short-term emission reduction measures include converting coal units to natural gas or other zero emission generation or in some cases, accelerating unit retirement.

However, as a market-based cap and trade program, CSAPR does not mandate any specific controls, or control installation dates, on generating units. For example, any new pollution control retrofit installations desired by unit operators do not have to be operational on January 1 of 2012 or January 1 of 2014. Controls installed after January 1 of any year simply reduce the number of allowances needed by a unit for compliance during the balance of that year (and future years) and surplus allowances created become available for compliance to other generation units. Ultimately, NERC's modeling projects CSAPR impacts will cause significant displacement of coal-fired megawatts, especially in 2012 and 2013.

Figure 62: CSAPR Concentrated Emission Reduction Burden



While coal generation will likely be displaced, CSAPR alone may not directly cause unit retirement. Companies will still have the option to comply by operating affected plants on a shorter time-frame, while also ensuring that generators are available to provided capacity to support reliability, especially during peak seasons and other periods when capacity is needed. Few studies have been published that identify the specific impacts of CSAPR to the electricity industry, yet most conclude very limited impacts on coal-fired on-peak capacity. EPA's CSAPR analyses project only 4.8 GW in coal unit retirements.[129] Although CSAPR alone will not likely force unit retirements, plant owners may still elect to retire older

[128] Including the need to switch to lower sulfur fuels.

[129] Rule Regulatory Impact Assessment (RIA) for Final Air Transport Rule (June 2011) EPA, pg 262

coal-fired units with higher operating costs as early as next year to comply with CSAPR as part of a combined environmental compliance strategy.

EPA's final CSAPR rule included some significant program differences from its earlier July 2010 draft proposal. These differences (versus its earlier proposal analyzed in the NERC 2010 EPA Assessment) include stricter emission caps, added and eliminated states from the program and increased the overall compliance costs. These changes have accelerated some unit retirement decisions and triggered the idling of additional units.

This update assumes that the program will be implemented as proposed and promulgated by EPA in July 2011 and does not consider EPA's more recent proposed rule that proposes to: 1) delay the Agency's "assurance provision" requirements from 2012 to 2014 to assist in the transition from CAIR to the CSAPR; and (2) to increase nine state emission budgets to address state, industry and ISO requests for increased state emission budgets and to address a limited number of errors in EPA model input assumptions as well as a few instances in which EPA modeling did not adequately address local system constraints or localized rules that may require "out of merit" economic dispatch of some generating units at certain times during the year.[130] The changes proposed by EPA in October will help mitigate the impact of the rule, particularly in 2012 and 2013.

Section 316(b) Cooling Water Intake Structures

Cooling water intake operation and structures are regulated under Section 316(b) of Clean Water Act (CWA). The 316(b) rule is implemented by the state water permitting agencies through the National Pollution Discharge Elimination System (NPDES) permit program of the CWA. EPA provides state permitting agencies with regulatory guidance and standards to determine Best Technology Available (BTA) to protect aquatic life from impingement (being trapped against the intake screen) and entrainment (passing through the screens and into the plant's cooling water system).

The prior version of the 316(b) rule that applied to existing generation facilities (known as the "Phase II Rule) was promulgated in 2004 and applied only to facilities with water usage greater than 50 million gallons per day (mgd), of which at least 25 percent was for cooling purposes.[131] However, many aspects of the Phase II Rule were invalidated by the U.S. Court of Appeals in 2007 and the EPA withdrew the rule and directed the state permitting agencies to continue to implement the 316(b) rule on a site-specific basis using their best professional judgment.[132] EPA published a proposed Phase II rule on April 20, 2011 that it is required to finalize under a Consent Agreement by July 2012.

[130] See October 14, 2011 "Revisions to Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone" (76
FR 63,860).

[131] The EPA promulgated rules applicable to cooling water intake structures at manufacturing facilities in three phases: Phase I for new generation facilities, Phase II for existing large generation facilities, and Phase III for all remaining manufacturing facilities, including small electric generators. Phase I is in effect and requires that all new generation facilities install closed cycle cooling. Phase III has now been merged into the remanded Phase II rulemaking described herein.

[132] The U.S. Supreme Court did review one aspect of the U.S. Court of Appeals opinion in the Phase II Rule. The Supreme Court determined that the EPA has the discretion under Section 316(b) to utilize a cost-benefit test on a site-specific basis to determine BTA for each affected facility.

For this update, the final rule is assumed to be in effect by the end of 2012. However, the proposed rule incorporates an extended compliance period to meet both the impingement mortality (IM) and the entrainment mortality (EM) standards. These requirements will be implemented through the NPDES permit renewal process which occurs in five year cycles. Unlike the air rules, there will not be a single date on which all plants must be in compliance with the BTA standards. The proposed rule sets forth a number of interim deadlines prior to the time that BTA is to be installed and operating. These are intended as milestones to ensure that the facility is obtaining the necessary site-specific data and performing the analyses required to determine the BTA for IM and EM. For facilities that were covered under the now-remanded Phase II Rule, the proposed rule provides for a five-year period (representing the initial permit term after the rule takes effect) to gather data about the facility and its cooling water intake structure and the source water body, to design and conduct an entrainment characterization study, and to perform technical feasibility and a cost–benefit analysis. The ultimate compliance date will vary by plant and will be determined by the state permitting director.

The 316(b) rule will apply to all current and future nuclear and fossil steam generating units, accounting for over 83 percent of 2010 U.S. generation. However, the greatest impact will be on those existing plants that have once-through cooling systems. Over 1,200 units with once-through cooling water systems were identified through EIA Form 923 and the older Form 767 (*Steam Electric Plant Operation and Design Report*) data filings by power generators. The affected units include 754 coal units, 405 oil/gas steam units and 42 nuclear units (60.5 GW). Generators such as peaking turbines, hydroelectric facilities, wind turbines, and solar PV panels do not use steam as the prime mover for generating electricity and, therefore, do not require additional water for cooling purposes. These generators are not subject to the requirements of this rule.

Major EPA rulemaking policy issues that could affect electric grid reliability are:

- Implementation period
- Applicability to existing structures
- BTA – the final IM and EM standards

In the original Phase II Rule, EPA established a flexible and cost-effective process that had no measurable effect on steam electric generating unit retirements. However, due to the need to meet the deficiencies determined by the Court of Appeals, the proposed rule is substantially different. It is also noted that in its opinion upholding the cost-benefit aspects of the Phase II Rule, the U.S. Supreme Court determined the EPA retains significant discretion in designing the rule.

However, EPA's 2011 draft 316 (b) rule is substantially different. The 2011 draft rule will require all steam generating stations to meet BTA standards for both fish IM and EM. The proposed 316(b) rule has two IM compliance alternatives for affected plants – strict numeric IM standards (not more than 31% mortality in any month and 12% on an average annual basis) or a velocity no greater than 0.5 fps at the cooling water intake. For those facilities that were not designed with the prescribed intake velocity, IM compliance will involve either a fish return system by means of a retrofit of the plant's travelling screens, or a diversion device like a velocity cap or a wedge wire screen attached to the intake pipe. While the EPA recognized the effectiveness of closed cycle cooling as the most effective means of

reducing IM via flow reductions, it did not propose it as BTA for IM because it is not available at all facilities and modified traveling screens are more cost-effective. The EPA has received significant comments from industry expressing concerns that even with state-of-the art traveling screens, it will be impossible to meet the numeric IM standards at some facilities due to site-specific conditions. In response, the EPA has indicated that it is reconsidering the IM standards to include an alternative technology standard. Under this alternative, facilities could install a pre-approved technology as BTA, including screens or a diversionary technology, and would be deemed compliant in lieu of meeting the numeric IM standards.

In its rule development, EPA had assumed this standard could be met by using modified traveling screens. However, some existing power plants that employ EPA's modified traveling screens technology have been unable to meet the proposed fish mortality standard. If the EPA does not include such an alternate technology standard in the final rule, IM compliance options would be severely limited at some plants and may require significant intake structure retrofits to meet the intake velocity of no greater than 0.5 feet per second. Should this not be available to a plant, the EPA-proposed strict fish IM standard may effectively force recirculating cooling water systems options independent of the site specific BTA entrainment standard.

Regarding the EM standards, the EPA did not designate closed cycle cooling, or any technology, as BTA. Rather, due to the site- specific nature of determining BTA for EM, the EPA delegated this determination to the state permitting directors.

EPA's draft 316(b) rule also contained four different approaches to setting a fish EM standard. Two of the proposed entrainment options would require affected facilities to have "***flow reduction commensurate with closed cycle cooling as BTA for entrainment***". Although not the preferred EPA option, these options represent the highest compliance cost policy outcome and were incorporated in the Strict Case of this update.

The other two options (including the preferred option) provide for BTA entrainment controls to be determined on a site specific basis. This policy approach allows EPA not to quantify specific BTA entrainment cost impact, since entrainment would remain undefined and left up to state regulators. The challenge for NERC's Moderate Case scenario is how state regulators will develop the BTA entrainment standards. EPA rules require states to follow an entrainment standard that reflects "maximum reduction in entrainment mortality" warranted after consideration of nine relevant factors. In other words, closed-cycle systems are EPA's default BTA technology unless other listed relevant factors make recirculating systems unfeasible. The nine factors are:

- Numbers/type of organisms entrained
- Entrainment impacts on waterbody
- Quantified and qualitative social benefits and costs
- Thermal discharge impacts
- Impacts on reliability of energy delivery within the immediate area
- Changes in particulate emissions and other pollutants associated with entrainment technologies

- Land availability
- Useful plant life
- Impacts on water consumption

However, of these factors, EPA only considered four issues to be important for the national standard BTA determination:

- **Energy reliability**—Grid reliability can be a cumulative impact from multiple retirements and not necessarily from any one facility contribution, except for local reliability concerns. Also, the projected reliability problem must occur in the "immediate area." Given the grid and industry's attempt to improve reliability, there is a significant risk that very few cases may qualify for different treatment under this provision. Because of the site-specific evaluation, a comprehensive, system-wide reliability study will be difficult to incorporate into an individual unit's effect on reliability.

- **Increased air emissions on a local basis associated with entrainment technologies**—Given that utility MACT will be in place prior to 316(b), emission increases from lost energy efficiency may not be significant or much different than new plant emission rates. EPA discussion also concludes that cooling tower emission effects would generally be limited to facility property and not an issue, with very few exceptions.

- **Land Availability**—EPA in its preamble states it has not identified any electric generating facility with more than 160 acres per GW capacity that EPA believes would be unable to construct retrofit cooling towers and that some facilities on smaller land parcels would still be able "to install closed cycle cooling by engineering creative solutions." This EPA criterion would suggest that the vast majority of power plant sites have sufficient land for cooling tower construction. As is the case with this update, EPA admits it lacks data to analyze land constraints, but quotes an Electric Power Research Institute (EPRI) report that indicates six percent of sites investigated had insufficient space for cooling tower systems. However EPA also suggests that higher cooling system retrofit difficulty does not mean that cooling towers would not be BTA, but would also depend upon the projected system benefits.

- **Remaining useful life of the facility**—EPA's preamble example is for a unit that would be shut down in 3 years versus 20 years. The NERC analysis already takes remaining lifetime into account in its analysis. However, the net impact may be that EPA uses this provision to force retirements within a negotiated time period. In either case, the oil/gas steam units, which are not used often, will be retired anyway.

Without a specific entrainment defined standard, regulators could set entrainment standards ranging from low cost screens to high cost recirculating cooling water systems.

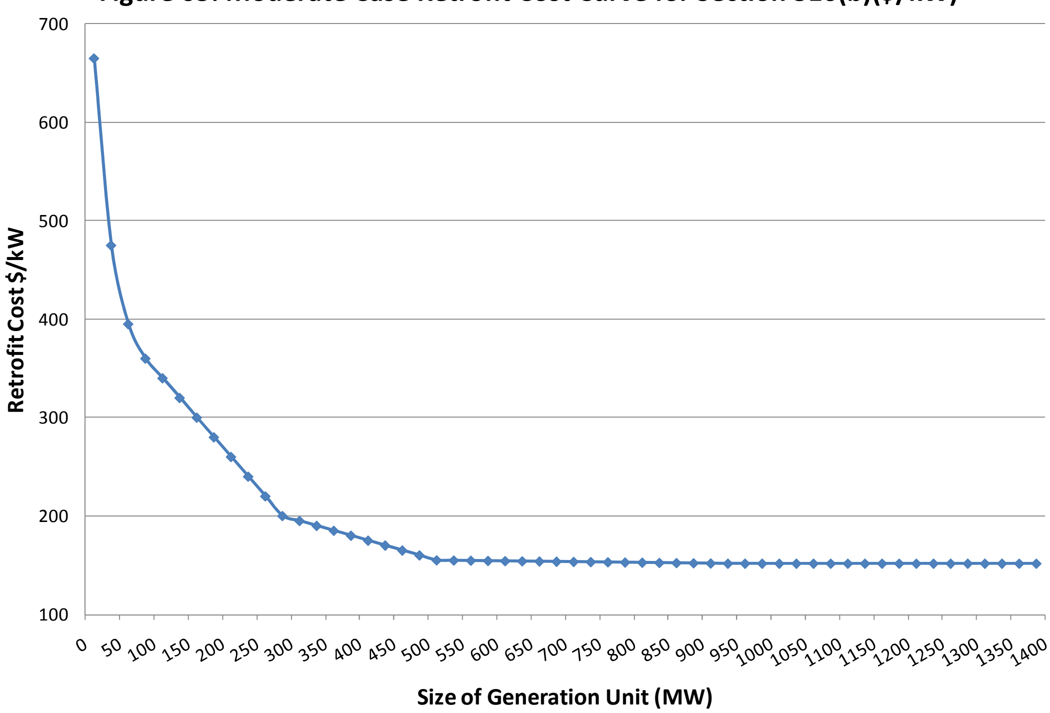
To gauge how strict state regulators would set the entrainment standard in the Moderate Case, an assessment of past state water supply and water permitting practices was made.[133] This review found Alabama, Arizona, California, Delaware, Florida, Georgia, New Mexico, New York, New Jersey, Texas and states in New England (accounting for 75 percent of affected capacity) have raised water supply concerns in the past that could potentially result in their regulators requiring recirculating water systems to meet the fish entrainment. The remaining states (25 percent of affected capacity) were assumed to require a combination of screens, barriers and seasonal flow limitations to comply with their fish entrainment standards.

Capital cost to convert from once-through cooling water to recirculating cooling water systems are derived from three prior engineering studies and industry cost surveys:

- EPRI's *Issues Analysis of Retrofitting Once-through Cooled Plants with Closed Cycle Cooling* (10/07)
- Maulbetsch Consulting EPRI Survey (7/2002) of 50 plant estimates
- Stone & Webster Study (7/2002) for Utility Water Assessment Group.

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 gallons per minute (gpm) (in 2010 dollars), 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 was applied. The base case costs applied in this update are shown below (Figure 63).

Figure 63: Moderate Case Retrofit Cost Curve for Section 316(b)($/kW)



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In addition to the capital conversion costs, the station would lose both capacity and energy with larger power consumption used to drive the cooling water pump. The capacity and energy losses estimated in the 2008 DOE study and applied in this update are shown below (Table 31).

Table 31: Capacity Derating/Energy Penalties Due to Cooling Tower Conversion

Assessment Areas	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%
PJM/MISO	1.60%	3.40%
SERC-W	0.90%	2.60%
SERC-SE	0.80%	2.40%
SERC-N	0.90%	2.60%
SERC-E	1.00%	2.80%
SPP	1.00%	2.80%
WECC-DSW	1.40%	2.70%
WECC-CALN/CALS	0.90%	2.50%
WECC-NWPP/WECC-BASIN	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)

The capital costs for the more flexible screen alternatives for the remaining alternatives were based upon preliminary EPRI cost estimates.

Under these policy interpretations, 25-35 GW of older oil/gas unit steam generating units (Moderate to Strict case) are estimated to be economically vulnerable for retirements in lieu of making the large capital retrofit investments in recirculating cooling water systems alone. These results are higher than EPA's published results in its March 2011 report *Economic and Benefit Analysis for Proposed Section 316(b) Existing Facilities Rule* (EPA 821-R-11-003). The EPA study assumed that only 1 GW of existing capacity would retire earlier by 2028 under its preferred option and 14 GW are projected for retirement earlier under its stricter forced recirculating system policy options. The EPA study did not quantify specific BTA entrainment cost impact under its preferred option as the entrainment standard would be determined by state regulators applying the nine criteria set forth in the proposed rule.

These referenced compliance costs and reliability impacts may be underestimated. First, the published studies used to develop the average capital cost estimates are based upon surveys done in 2002 and 2007. Open-loop to closed-loop conversions are rare and no historic cost data has been published. Since these surveys, the costs of environmental project construction have escalated. 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 considerations. Finally, given the rule implementation period and the large amount of affected power plants (252 GW), 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 in the past. To capture these potential risks, the Strict Case scenario includes 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.

Coal Combustion Residuals

Concerns raised by the December 2008 TVA 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 issued a draft rule on the disposal of CCRs for public comment in June 2010. A final rule has still not been issued. For this study, the final rule is assumed to be completed in 2012 with implementation expected to start in 2013-2015 and full compliance by 2018.

This EPA rule is expected to regulate 136 million tons per year of coal ash and solid byproducts currently produced by the coal-fired stations. Major policy issues that will impact electric grid reliability include:

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

EPA has proposed conversion of all coal ash handling systems from utility-boilers to dry based systems. Two options were provided 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 or cap existing ash ponds. Such a ruling may cause up to 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 per year (TPY) of ash disposal, and close and/or cap the existing 500 ash ponds in operation.

In addition, a hazardous waste designation under Subtitle C would likely eliminate the market for 20 million tons of ash currently resold into the market. However, EPA is considering a “special waste” designation that would allow “beneficial” reuse of the substance to continue. Hazardous waste designation without exceptions would expand the existing hazardous waste disposal market from its current size of 2 million tons per year.

Prior public studies examining the ash disposal issue on power plant operation are limited. To provide context for this assessment, 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. This 2009 industrial study concluded that EPA’s draft rule could directly affect operations at 397 coal-fired generating units (175 GW). The EOP Group study estimated bottom ash conversion costs of $30 million per unit and this assumption are used in the Moderate Case of this assessment. In addition, at some stations, the ash ponds also dispose of fly ash (15 million TPY) requiring an additional

$3 billion investment to convert from wet to dry handling systems. Outside conversion costs, stations would need to build alternative wastewater treatment facilities at 155 facilities ranging in cost from $80 million without a flue gas desulfurization system (FGD) to $120 million with an FGD per facility. These conversions would provide storm water and/or FGD scrubber sludge treatment currently handled by the ash ponds. Ash pond closure costs were estimated to be $30 million per pond.

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

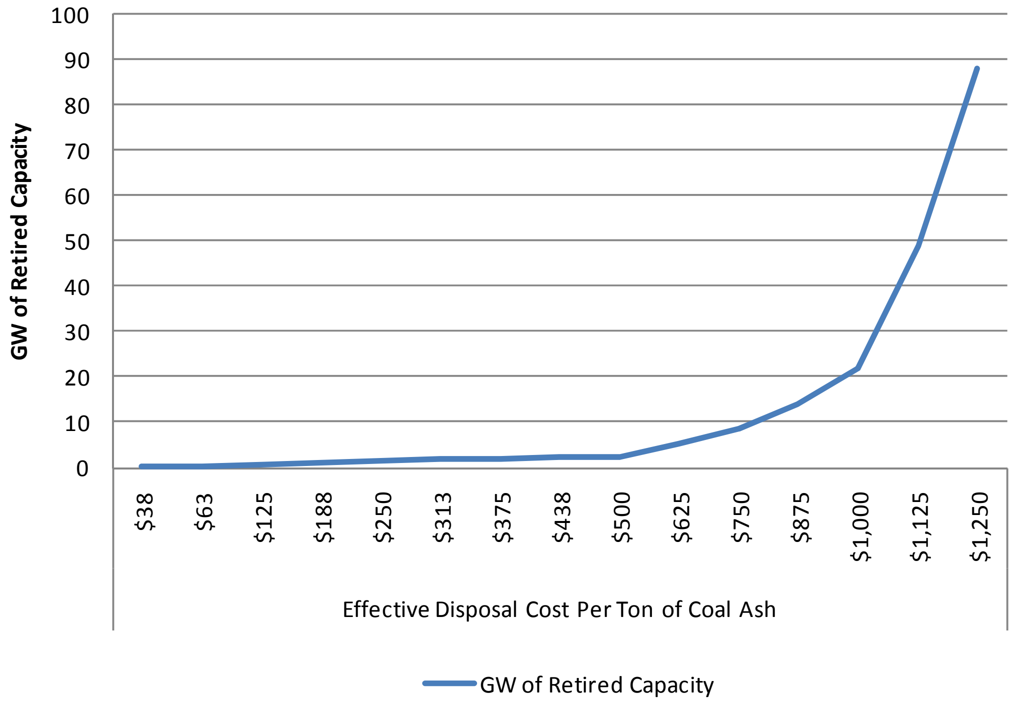
- Land acquisition for a landfill or expanded wastewater treatment facilities.
- Increased disposal if ash was designated as hazardous waste.
- Existing ash pond closures.

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 and would not be incorporated into the power supplier's unit retirement decision.

A total of 359 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 an individual generator basis. The additional EOP ash waste disposal costs of $15 per ton for handling in a regulated non-hazardous onsite landfill were added to the unit operating costs in the Moderate Case of this update. The pond closure and remediation costs are assumed to become sunk costs that would be incurred independent of the future power plant operations. Therefore, only incremental costs tied to 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.

To account for potential underestimation of investment requirements and based upon conversations with various utilities, the capital compliance cost uncertainty is likely to be +/-25 percent. To account for potentially higher costs under stricter Subtitle C guidelines, landfill costs are assumed to be much higher at $37.50 per ton (2010$) in the Strict Case, which is also similar to the EPA study's estimated disposal costs. Further, in lieu of conducting site-specific analyses, a sensitivity analysis is performed across a wide range of ash disposal costs from $37.50 up to $1,250 per ton (Figure 64). The costs are believed to be contained well 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 64: Sensitivity of Retirements as a Function of Higher Assumed Coal-Ash Disposal Costs due to Coal Combustion Residuals regulations



Utility Air Toxics Rule

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. For the power sector, the listed air toxics of greatest concern are mercury (coal), acid gases (coal), arsenic (coal), vanadium (oil) and chromium (oil). EPA had originally developed a cap and trade program for controlling mercury emissions. However, the U.S. Court of Appeals overturned this initial program in 2008 and concluded that the Clean Air Act specifically required EPA to develop Maximum Achievable Control Technology (MACT) emissions standards for air toxics listed in the Clean Air Act and did not allow a cap and trade program. The Act was specific in how these MACT emission rate limitations were calculated (*i.e.,* average emission rate of lowest emitting 12 percent of the source population) and how quickly they were to be implemented (*i.e.,* 3 years after final rule with up to a one year extension waiver).

The Clean Air Act requires existing plants to comply with the Utility Air Toxics Rule as expeditiously as practicable, but in no event later than three years after the effective date of the rule. The proposed Utility Air Toxics Rule provides the maximum amount of compliance time permitted by the Act. The Act authorizes EPA or a state with an approved Title V permitting program to grant a one-year extension of time "if necessary for the installation of controls." In addition, the Act authorizes the President to exempt a source from compliance for a period of not more than 2 years if the President determines that "the technology to implement such standard is not available and that it is in the national security interests of the United States to do so." Finally, EPA can exercise its enforcement discretion under the Act to allow more time if a source has justified the need for an extension.

EPA published its draft Utility Air Toxics Rule in May 2011 and has announced that it will issue its final regulations in December 2011. Assuming that the one year extension is granted when needed, power suppliers will have until December 2015 to design, permit and implement the needed measures to meet the emission rate limitations for acid gases, mercury and non-mercury metals. This assumption is used in both the Moderate and Strict Cases. All coal-fired power plant units must meet the emissions standards at each unit: allowance trading between units and reduced unit use are not compliance options.

In its draft proposal, EPA proposed the acid gas rate limitation for existing coal-fired units to be either (1) 0.002 lbs of hydrochloric acid per MMBtu, or alternatively (2) 2.0 pounds of SO_2/MWH (0.20 lbs SO_2/MMBtu). Given the US coal chlorine content for the major producing basins, this limit effectively requires bituminous and lignite coal-fired units to retrofit a FGD scrubber (at $400-$900/kW) and a dry sorbent injection ($50/kW) or spray dry scrubber ($400-$900/kW) on sub-bituminous coal units. Roughly 72.5 percent of existing coal-fired capacity have existing FGD equipment or have announced plans to retrofit such equipment. The remaining 27.5 percent (89 GW) of uncontrolled existing capacity could be forced to retrofit with FGD controls or retire by December 2015. Given 29 GW have already announced their retirement plans, scrubber decisions to meet acid gas limitations by 2015 remain for 60 GW of uncontrolled coal-fired capacity.

In addition, the proposed EPA Utility Air Toxic rule also includes a total particulate emission limitation of 0.03 pounds (lbs)/MMBtu as a surrogate for non-mercury metals, which is applicable to coal-fired units. Given the average ash content of coals, this limit will require power plants to remove 99.6-99.8 percent of the particulate matter in the flue gas stream. Such high performance can only be achieved on a consistent basis by fabric filter controls that cost between $200-$400/kW to retrofit. Given that 75 percent of US coal-fired capacity does not have, nor has announced plans for such controls, the compliance costs will be significant for those plants to continue producing power beyond 2015. The 2011 Edison Electric Institute[134] study has made a similar assumption. In contrast, EPA analyses[135] suggested up to 30 percent of coal units with electrostatic precipitators may be able to meet the particulate limit without retrofitting fabric filter controls. As a result, EPA projects a much lower 166 GW of existing coal-fired capacity would retrofit fabric filter controls under this rule.

EPA proposed a mercury emission standard of 1.2 lbs/TBtu for units that burn non-lignite coal and 4.0 lbs/TBtu for lignite-fired units. These limits will likely be met with the forced FGD controls for acid gas compliance and could require activated carbon injection systems ($15-$25/kW retrofit capital cost) for lignite and sub-bituminous coal units. Plants that burn coals with high chlorine content (bituminous coal) that are equipped with SCR and newer wet FGD units may be able to achieve the proposed mercury emission standard without activated carbon injection (ACI.) While such controls will add to plant operating costs and may eliminate ash reuse applications, the capital cost for mercury controls alone is unlikely to require any additional coal unit retirements.

[134] Potential Impacts of Environmental Regulation on the US Generation Fleet (Jan 2011) ICF for EEI pg 43

[135] Regulatory Impact Analysis of the Proposed Toxics Rule: Final Report (EPA March 2011)

The analysis in this update applies environmental control cost curves to develop unit-specific compliance costs estimates. The increased production cost, due to the new pollution controls, are then compared to unit production costs of replacement power. In the Moderate Case of this study, investments are made on existing coal units when FGD and fabric filter equipment are not present, or planned. Also, halide treated activated carbon injection (HACI) systems are added for lignite and sub-bituminious coal types. These control retrofit costs were developed for an average difficulty plant. The retrofit capital cost curves for FGD and fabric filter controls are shown below (Figure 65 and Figure **66**). Oil-fired units (109.7 GW) are assumed to meet their air toxic limits through tighter oil specifications at the refinery. Compliance costs increase by 25 percent in the Strict Case.

The combination of the three contaminants of the Utility Air Toxic Rule will require a large capital investment in scrubbers, fabric filters and activated carbon injection systems that EPA estimated would cost $10 to 11 billion per year to finance, build and operate. The EPA analysis assumed that 9.9 GW of coal-fired capacity would retire from the draft rule alone.[136]

Figure 65: Average FGD Retrofit Capital Costs

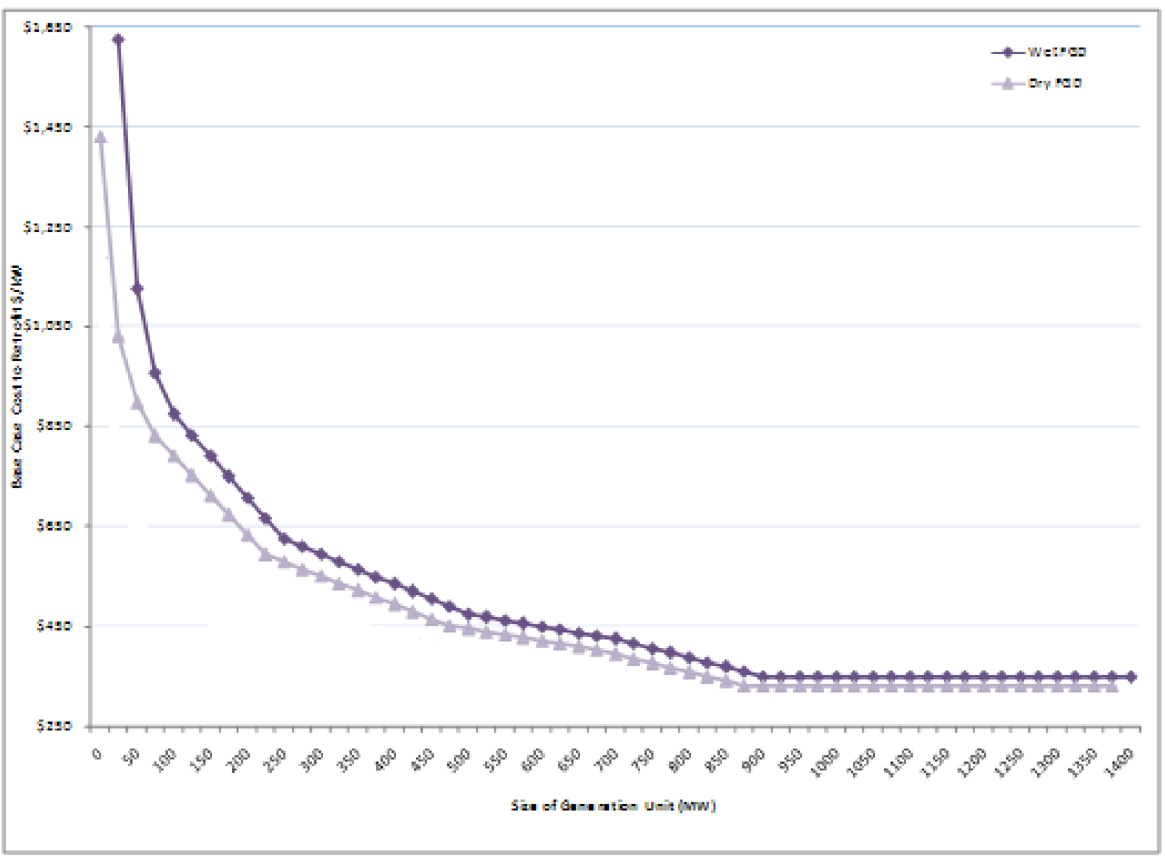


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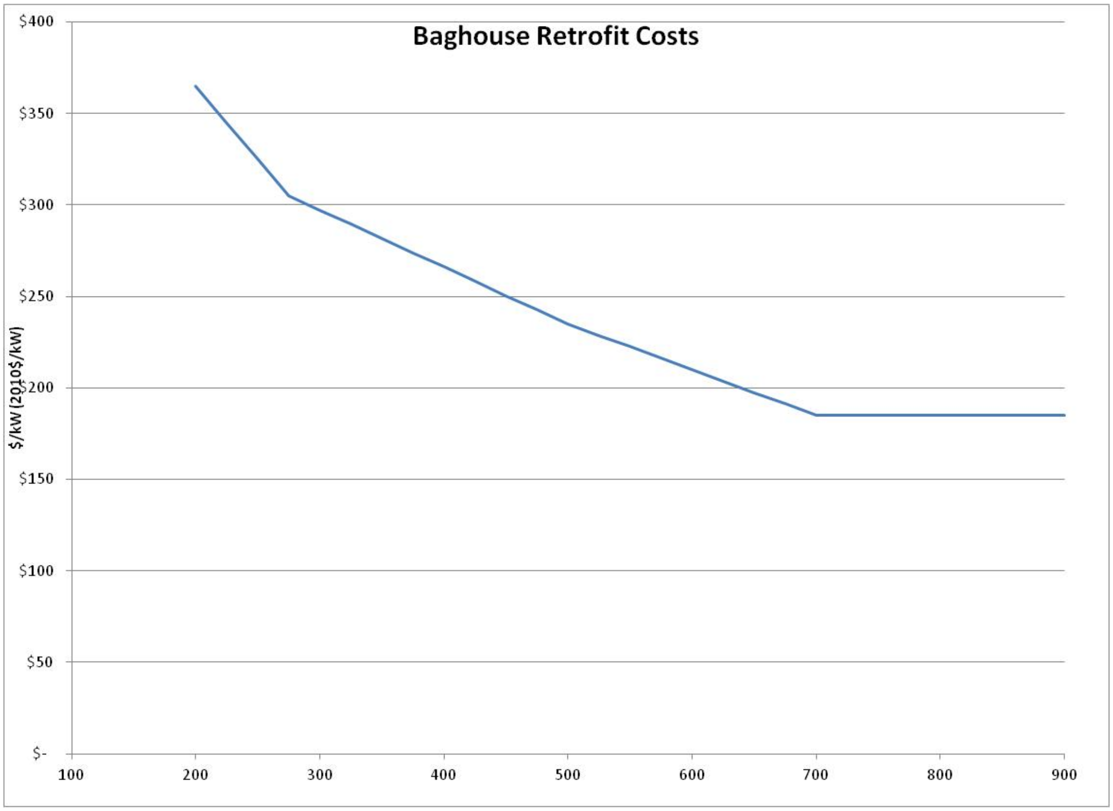
Figure 66: Retrofit Capital Cost for Baghouse/Fabric Filter Control Systems on Coal-Fired Power Plants



Integrated and Cumulative Effects of Environmental Regulation Compliance

Power industry unit retirement decisions will not be based upon any single factor, but the combined effect from all the EPA regulations, economic conditions, and potential future requirements (*e.g.,* from stricter national ambient air quality standards for SO_2, ozone and fine particulate, carbon control, national clean energy standards, effluent guidelines, etc.) that may be proposed over the remaining lifetime of the power plant facility.

EPA regulations may require existing coal-fired capacity to make capital investments to add control technologies to address air, waste, and water regulations. Those coal-fired units that determine these control modifications are not cost-effective will retire sooner. With natural gas prices becoming more competitive with the emergence of low cost shale gas, generators may be unable to fully recover their retrofit environmental investment costs and may elect to retire higher cost coal-fired capacity.

The cumulative effect of the four EPA rules is provided below (Table 32 through Table 34) for 2013, 2015 and 2018. As is shown in Table 32, an additional 11.4 GW of coal-fired capacity retirements is projected by 2013, due mostly to the combination of the Utility Air Toxics Rule and CSAPR. While these units are expected to retire under the Utility Air Toxics rule assumptions, the dates are accelerated to provide the needed incremental reductions needed for CSAPR compliance strategies.

By 2015, the bulk of the remaining coal-fired capacity retirements are projected to comply with the December 2015 Utility Air Toxics Rule deadline (noting that this update assumes that certain units are able to gain a one-year extension). As shown in Table 33, between 3.6 and 24.4 GW of coal-fired capacity is economically vulnerable by 2015. This table quantifies only the incremental impact and excludes the 37.6 GW of already announced and committed retirements—some of which have been directly attributed to the environmental regulations.[137] The measurement used in this assessment is Planning Reserve Margins, which provide an indication for the need for additional resources to maintain bulk power system reliability. Further, this assessment does not take into account local reliability affects resulting from individual unit retirements, such as transmission system voltage or stability impacts, nor the additional costs of transmission facilities required to support reliability.

In this update, the assumed compliance deadline for 316(b) rule is 2018. These rules are projected to trigger large amounts of older oil/gas-fired steam generating capacity retirements as well as retirement of some older coal-fired units that have already added sufficient environmental controls to meet the Utility Air Toxics and CSAPR requirements, but would be unable to justify the combination of needed cooling tower retrofit investment and higher ash disposal costs. The total economically vulnerable capacity could reach 36 GW under the Moderate Case, and up to 59 GW in the Strict Case (Table 34). However, total capacity reductions will depend on the degree to which state regulators mandate closed-loop cooling system.[138]

[137] These units faced economic challenges based on a variety of reasons, including gas-prices and demand forecasts. In addition, some plants have announced retirements as a result of previous settlements with government agencies requiring the installation of pollution controls to comply with regulations other than the four that specifically assessed in this report.

[138] Impacts of individual rules are provided in the Additional Background Information section.

Table 32: Cumulative Projected Incremental Capacity Losses through 2013

Moderate Case Projections				Strict Case Projections			
Combined Impacts - 2013				Combined Impacts - 2013			
	Moderate Case				Strict Case		
	Derated (MW)	Retired (MW)	Total		Derated (MW)	Retired (MW)	Total
Coal Units				**Coal Units**			
ERCOT	-	-	-	ERCOT	76	-	76
FRCC	-	-	-	FRCC	13	-	13
ISO-NE	-	-	-	ISO-NE	-	-	-
NYISO	-	-	-	NYISO	12	-	12
MAPP	-	-	-	MAPP	-	-	-
MISO	-	-	-	MISO	387	1,679	2,066
PJM	-	-	-	PJM	225	3,173	3,398
SERC-N	-	-	-	SERC-N	61	264	325
SERC-W	-	-	-	SERC-W	100	75	175
SERC-SE	-	-	-	SERC-SE	72	1,555	1,626
SERC-E	-	-	-	SERC-E	14	1,018	1,032
SPP	-	-	-	SPP	256	811	1,067
CAL-N	-	-	-	CAL-N	-	-	-
CAL-S	-	-	-	CAL-S	-	-	-
Basin	-	-	-	Basin	-	-	-
Desert SW	-	-	-	Desert SW	-	-	-
RMPA	-	-	-	RMPA	-	-	-
NWPP	-	-	-	NWPP	-	-	-
TOTAL	-	-	-	TOTAL	1,217	8,574	9,791
O/G-ST Units				**O/G-ST Units**			
ERCOT	-	-	-	ERCOT	-	-	-
FRCC	-	-	-	FRCC	-	-	-
ISO-NE	-	-	-	ISO-NE	-	-	-
NYISO	-	-	-	NYISO	-	-	-
MAPP	-	-	-	MAPP	-	-	-
MISO	-	-	-	MISO	-	-	-
PJM	-	-	-	PJM	-	-	-
SERC-N	-	-	-	SERC-N	-	-	-
SERC-W	-	-	-	SERC-W	-	-	-
SERC-SE	-	-	-	SERC-SE	-	-	-
SERC-E	-	-	-	SERC-E	-	-	-
SPP	-	-	-	SPP	-	-	-
CAL-N	-	-	-	CAL-N	-	-	-
CAL-S	-	-	-	CAL-S	-	-	-
Basin	-	-	-	Basin	-	-	-
Desert SW	-	-	-	Desert SW	-	-	-
RMPA	-	-	-	RMPA	-	-	-
NWPP	-	-	-	NWPP	-	-	-
TOTAL	-	-	-	TOTAL	-	-	-

Table 33: Cumulative Projected Incremental Capacity Losses through 2015

	Moderate Case Projections				Strict Case Projections		
	Combined Impacts - 2015				Combined Impacts - 2015		
	Moderate Case				Strict Case		
	Derated (MW)	Retired (MW)	Total		Derated (MW)	Retired (MW)	Total
Coal Units				**Coal Units**			
ERCOT	267	-	267	ERCOT	267	-	267
FRCC	176	-	176	FRCC	156	1,592	1,748
ISO-NE	93	144	237	ISO-NE	88	239	327
NYISO	77	74	151	NYISO	77	74	151
MAPP	8	-	8	MAPP	10	0	10
MISO	519	1,110	1,629	MISO	1,400	3,583	4,982
PJM	606	2,850	3,456	PJM	1,323	5,725	7,048
SERC-N	175	724	899	SERC-N	435	1,690	2,125
SERC-W	95	0	96	SERC-W	95	265	360
SERC-SE	318	1,358	1,675	SERC-SE	265	2,942	3,206
SERC-E	110	808	918	SERC-E	303	945	1,248
SPP	198	187	385	SPP	415	285	700
CAL-N	4	15	18	CAL-N	2	67	68
CAL-S	4	83	87	CAL-S	-	184	184
Basin	29	39	68	Basin	35	39	74
Desert SW	34	-	34	Desert SW	34	-	34
RMPA	23	89	111	RMPA	53	203	256
NWPP	34	12	46	NWPP	40	12	52
TOTAL	2,770	7,491	10,261	TOTAL	4,996	17,844	22,840
O/G-ST Units				**O/G-ST Units**			
ERCOT	-	-	-	ERCOT	-	-	-
FRCC	-	-	-	FRCC	-	-	-
ISO-NE	-	-	-	ISO-NE	-	-	-
NYISO	-	-	-	NYISO	-	-	-
MAPP	-	-	-	MAPP	-	-	-
MISO	-	-	-	MISO	-	-	-
PJM	-	-	-	PJM	-	-	-
SERC-N	-	-	-	SERC-N	-	-	-
SERC-W	-	-	-	SERC-W	-	-	-
SERC-SE	-	-	-	SERC-SE	-	-	-
SERC-E	-	-	-	SERC-E	-	-	-
SPP	-	-	-	SPP	-	-	-
CAL-N	-	-	-	CAL-N	-	-	-
CAL-S	-	-	-	CAL-S	-	-	-
Basin	-	-	-	Basin	-	-	-
Desert SW	-	-	-	Desert SW	-	-	-
RMPA	-	-	-	RMPA	-	-	-
NWPP	-	-	-	NWPP	-	-	-
TOTAL	-	-	-	TOTAL	-	-	-

Table 34: Cumulative Projected Incremental Capacity Losses through 2018

Moderate Case Projections				Strict Case Projections			
Combined Impacts - 2018				Combined Impacts - 2018			
	Moderate Case				Strict Case		
	Derated (MW)	Retired (MW)	Total		Derated (MW)	Retired (MW)	Total
Coal Units				**Coal Units**			
ERCOT	267	-	267	ERCOT	267	-	267
FRCC	176	-	176	FRCC	156	1,592	1,748
ISO-NE	93	144	237	ISO-NE	88	239	327
NYISO	77	74	151	NYISO	77	74	151
MAPP	8	-	8	MAPP	10	0	10
MISO	519	1,110	1,629	MISO	1,400	3,583	4,982
PJM	606	2,850	3,456	PJM	1,323	5,725	7,048
SERC-N	175	724	899	SERC-N	435	1,690	2,125
SERC-W	95	0	96	SERC-W	95	265	360
SERC-SE	318	1,358	1,675	SERC-SE	265	2,942	3,206
SERC-E	110	808	918	SERC-E	303	945	1,248
SPP	198	187	385	SPP	415	285	700
CAL-N	4	15	18	CAL-N	2	67	68
CAL-S	4	83	87	CAL-S	-	184	184
Basin	29	39	68	Basin	35	39	74
Desert SW	34	-	34	Desert SW	34	-	34
RMPA	23	89	111	RMPA	53	203	256
NWPP	34	12	46	NWPP	40	12	52
TOTAL	2,770	7,491	10,261	TOTAL	4,996	17,844	22,840
O/G-ST Units				**O/G-ST Units**			
ERCOT	119	5,065	5,184	ERCOT	105	5,593	5,698
FRCC	27	904	931	FRCC	27	904	931
ISO-NE	4	4,898	4,901	ISO-NE	-	5,015	5,015
NYISO	201	4,096	4,297	NYISO	195	4,291	4,486
MAPP	-	-	-	MAPP	-	-	-
MISO	-	-	-	MISO	-	424	424
PJM	-	903	903	PJM	2	3,632	3,634
SERC-N	-	-	-	SERC-N	-	-	-
SERC-W	-	-	-	SERC-W	190	3,134	3,324
SERC-SE	-	237	237	SERC-SE	-	349	349
SERC-E	-	-	-	SERC-E	-	84	84
SPP	-	-	-	SPP	29	2,523	2,551
CAL-N	-	2,138	2,138	CAL-N	-	2,138	2,138
CAL-S	48	6,439	6,487	CAL-S	36	6,924	6,960
Basin	-	-	-	Basin	1	113	114
Desert SW	5	418	423	Desert SW	2	523	525
RMPA	-	-	-	RMPA	-	84	84
NWPP	-	-	-	NWPP	-	-	-
TOTAL	404	25,097	25,502	TOTAL	588	35,730	36,318

Capacity losses modeled in this analysis are highly sensitive to changes in natural gas prices. All the projected capacity losses outlined above were projected using EVA's Base natural gas and delivered coal prices. For the 2018 case, sensitivity studies were run to quantify the sensitivity of the retirement decisions to a range of +/- $2.00/MMBtu from the EVA Base Henry Hub (HH) natural gas price. In addition, EVA has developed high and low natural gas price forecasts that reflect our interpretation of a 90 percent confidence level incorporating the full range of reasonable potential outcomes of market, technology and regulatory changes. Sensitivity of the 2018 coal unit retirements (excludes derate capacity losses) are shown below (Table 35).

Table 35: Projected 2018 Coal Retirements Based on Gas-Price Sensitivity

Year	Base - $2 NG Price $/MMBtu	Low HH NG Price $/MMBtu	Base HH NG Price $/MMBtu	High HH NG Price $/MMBtu	Base+ $2 NG Price $/MMBtu
2013	$2.47	$4.27	$4.53	$5.07	$6.60
2014	$2.82	$4.72	$4.92	$5.50	$7.02
2015	$3.42	$5.31	$5.54	$5.84	$7.67
2016	$3.65	$5.49	$5.81	$6.19	$7.96
2017	$3.89	$5.68	$6.08	$6.56	$8.26
2018	$4.15	$5.88	$6.37	$6.93	$8.59
2019	$4.51	$6.08	$6.76	$7.32	$9.02
2020	$4.89	$6.28	$7.17	$7.71	$9.45
2021	$4.99	$6.49	$7.31	$7.99	$9.62
2022	$5.11	$6.70	$7.46	$8.28	$9.81
2023	$5.30	$6.91	$7.69	$8.58	$10.07
2024	$5.50	$7.13	$7.92	$8.89	$10.34
2025	$5.92	$7.36	$8.37	$9.20	$10.83
2026	$6.02	$7.52	$8.50	$9.45	$10.99
2027	$6.11	$7.69	$8.63	$9.71	$11.16
2028	$6.20	$7.86	$8.75	$9.97	$11.31
2029	$6.31	$8.03	$8.90	$10.23	$11.49
2030	$6.44	$8.21	$9.06	$10.51	$11.69
Moderate Case (MW)	**13,261**	**9,879**	**7,491**	**7,062**	**5,678**
Strict Case (MW)	**34,570**	**19,755**	**17,844**	**14,390**	**10,665**

Note: Base-$2 HH and Base+$2 HH vary by $2 Real from base Henry Hub

A significant retrofit effort is expected over the next ten years in order to comply with proposed EPA regulations. Environmental controls are expected to be put in place to meet air regulations by the end of 2015. In total, between 576 and 677 coal-fired unit retrofits (Moderate and Strict Case, respectively) will be needed by the end of 2015, totaling 234 to 258 GW of retrofitted coal capacity (Table 36).[139] For water regulations, a majority of the retrofits are expected to be performed beyond 2015. While the compliance date for 316(b) is assumed to be in 2018, retrofits are likely to continue into 2020 and beyond depending on the individual circumstances and requirements for each plant; therefore, these retrofits are not shown.

[139] These values do not include retrofits that would be needed to meet 316(b) compliance.

Table 36: Retrofits Needed by End of 2015 (by Number of Units and Capacity)

	2015			
	Moderate Case		Strict Case	
	Number	MW	Number	MW
ERCOT	23	13,424	27	15,720
FRCC	16	7,357	17	7,436
ISO-NE	8	1,808	6	1,713
NYISO	9	1,890	10	1,890
MAPP	2	419	5	1,120
MISO	138	51,979	156	55,038
PJM	120	54,669	148	59,195
SERC-N	56	19,238	70	21,500
SERC-W	9	5,520	9	5,520
SERC-SE	34	19,503	43	20,822
SERC-E	31	14,156	35	15,048
SPP	59	22,106	65	23,135
CAL-N	2	106	1	54
CAL-S	1	101	-	-
Basin	15	5,764	21	8,265
Desert SW	21	7,997	27	10,101
RMPA	23	4,058	27	6,694
NWPP	9	4,277	10	4,384
TOTAL	**576**	**234,371**	**677**	**257,633**

Constricted compliance deadlines may challenge the electric industry's planning horizons, existing planning processes and typical construction schedules. Successful implementation of environmental regulations will be highly dependent on the ability of units needed for reliability to obtain the necessary time needed to comply with certain requirements. Given the timelines for compliance, many of the affected units may need to take maintenance outages concurrently. The need to take multiple units out-of-service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns during maintenance periods.

Reliability Assessment

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. Where Planning Reserve Margins fall below zero there is a basic inability to serve load with projected resources.

Resources from these ten-year projections are reduced to form the scenario cases (Moderate Case and Strict Case—previously described in the report) and the resulting Planning Reserve Margins are calculated. This update includes a comparison of the impacts on Planning Reserve Margin for the years 2013, 2015, and 2018 based on the *2011 Long-Term Reliability Assessment* reference case. The resulting Planning Reserve Margin is compared to the NERC Reference Margin Level to determine if more resources may be needed. For the resource adequacy assessment, NERC chose a range of resource categories to evaluate Planning Reserve Margins for these scenarios. The range includes Anticipated Capacity Resources on the low-end and Adjusted Potential Capacity Resources on the high-end.[140]

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 61 GW reduction of incremental coal, oil, and gas-fired generation capacity is identified as economically vulnerable for retirement during the scenario timeframe. Absent sufficient industry response, the reduction in capacity significantly affects projected Planning Reserve Margins for a majority of the Assessment Areas in the 2018 Strict Case. Potentially significant reductions in capacity by 2015 may require heightened concentration towards the addition of resources; however, for 2015, in a majority of the Assessment Areas, retirements do not appear to significantly impact Planning Reserve Margins. Rather, the need for retrofits and installation of environmental controls by that year is the primary concern.

Additionally, more transmission 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, operational or stability impacts to the transmission system in this assessment, constructing new transmission or refurbishing existing transmission may be required. These effects on local reliability can create additional timing challenges. For example, transmission system enhancements and reconfiguration may be necessary in some areas, which may create additional timing issues if transmission facilities take relatively longer to construct than generation.

In this update, NERC did not review the potential impact on scheduled maintenance to account for any retrofit work on existing units. The assumption is that all retrofit work will be accomplished during normal maintenance periods, and the reserves available during those maintenance periods will be sufficient to accommodate the increased retrofit work load. However, this may not be the case as a

[140] Refer to the *Terms Used in This Report* section for detailed definitions regarding supply/resource categories.

significant industry-wide retrofit effort over the course of a short timeframe could add unforeseen stresses.

The resource adequacy assessment results are highlights by Assessment Area in Table 37 through Table 45. Planning Reserve Margins impacts are illustrated in Figure 67 through Figure 72.

Note: For the WECC, individual Assessment Area capacity reductions were aggregated to calculate the WECC US Planning Reserve Margin.

Resource Adequacy Assessment Results: 2013

Table 37: 2013 Reference Case

	Total Internal Demand (MW)	Anticipated Capacity (MW)	Adjusted Potential (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	NERC Reference Margin Level (%)
United States						
ERCOT	67,362	76,635	78,671	13.8%	16.8%	13.8%
FRCC	47,446	58,205	58,401	22.7%	23.1%	15.0%
MISO	94,834	114,509	131,651	20.7%	38.8%	15.0%
MRO-MAPP	5,331	7,016	7,016	31.6%	31.6%	15.0%
NPCC-New England	28,525	33,361	37,726	17.0%	32.3%	15.0%
NPCC-New York	33,433	45,814	45,960	37.0%	37.5%	15.5%
PJM	162,489	200,244	203,310	23.2%	25.1%	15.0%
SERC-E	44,863	56,526	56,526	26.0%	26.0%	15.0%
SERC-N	47,359	61,080	61,605	29.0%	30.1%	15.0%
SERC-SE	51,649	63,638	66,668	23.2%	29.1%	15.0%
SERC-W	25,912	34,589	40,882	33.5%	57.8%	15.0%
SPP	55,149	69,226	73,665	25.5%	33.6%	13.6%
WECC US	144,881	200,779	202,109	38.6%	39.5%	14.2%
Total	**809,235**	**1,021,622**	**1,064,190**	**26.2%**	**31.5%**	**15.0%**

Table 38: 2013 Moderate Case Results

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	-	76,635	78,671	13.8%	16.8%
FRCC	-	58,205	58,401	22.7%	23.1%
MISO	-	114,509	131,651	20.7%	38.8%
MRO-MAPP	-	7,016	7,016	31.6%	31.6%
NPCC-New England	-	33,361	37,726	17.0%	32.3%
NPCC-New York	-	45,814	45,960	37.0%	37.5%
PJM	-	200,244	203,310	23.2%	25.1%
SERC-E	-	56,526	56,526	26.0%	26.0%
SERC-N	-	61,080	61,605	29.0%	30.1%
SERC-SE	-	63,638	66,668	23.2%	29.1%
SERC-W	-	34,589	40,882	33.5%	57.8%
SPP	-	69,226	73,665	25.5%	33.6%
WECC US	-	200,779	202,109	38.6%	39.5%
Total	**-**	**1,021,622**	**1,064,190**	**26.2%**	**31.5%**

Table 39: 2013 Strict Case Results

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	76	76,559	78,595	13.7%	16.7%
FRCC	13	58,192	58,388	22.6%	23.1%
MISO	2,066	112,443	129,585	18.6%	36.6%
MRO-MAPP	0	7,016	7,016	31.6%	31.6%
NPCC-New England	0	33,361	37,726	17.0%	32.3%
NPCC-New York	12	45,802	45,948	37.0%	37.4%
PJM	3,398	196,846	199,912	21.1%	23.0%
SERC-E	1,032	55,494	55,494	23.7%	23.7%
SERC-N	325	60,755	61,280	28.3%	29.4%
SERC-SE	1,626	62,012	65,042	20.1%	25.9%
SERC-W	175	34,414	40,707	32.8%	57.1%
SPP	1,067	68,159	72,598	23.6%	31.6%
WECC US	0	200,779	202,109	38.6%	39.5%
Total	**9,791**	**1,011,831**	**1,054,399**	**25.0%**	**30.3%**

Figure 67: 2013 Peak Anticipated Reserve Margin Scenario Impacts

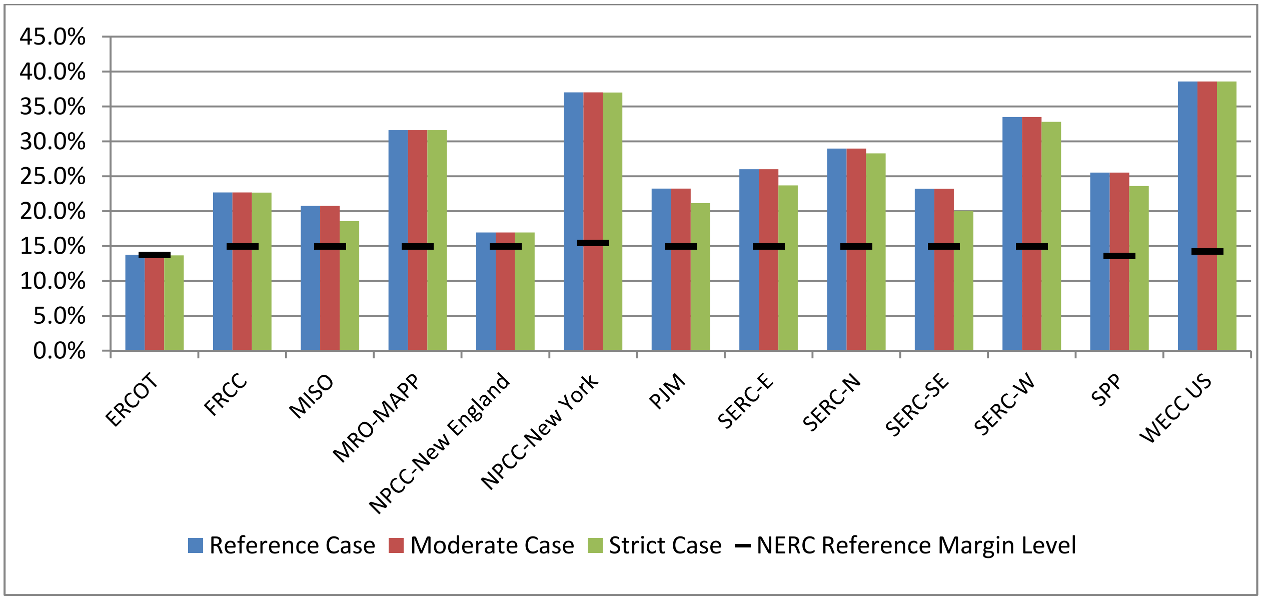
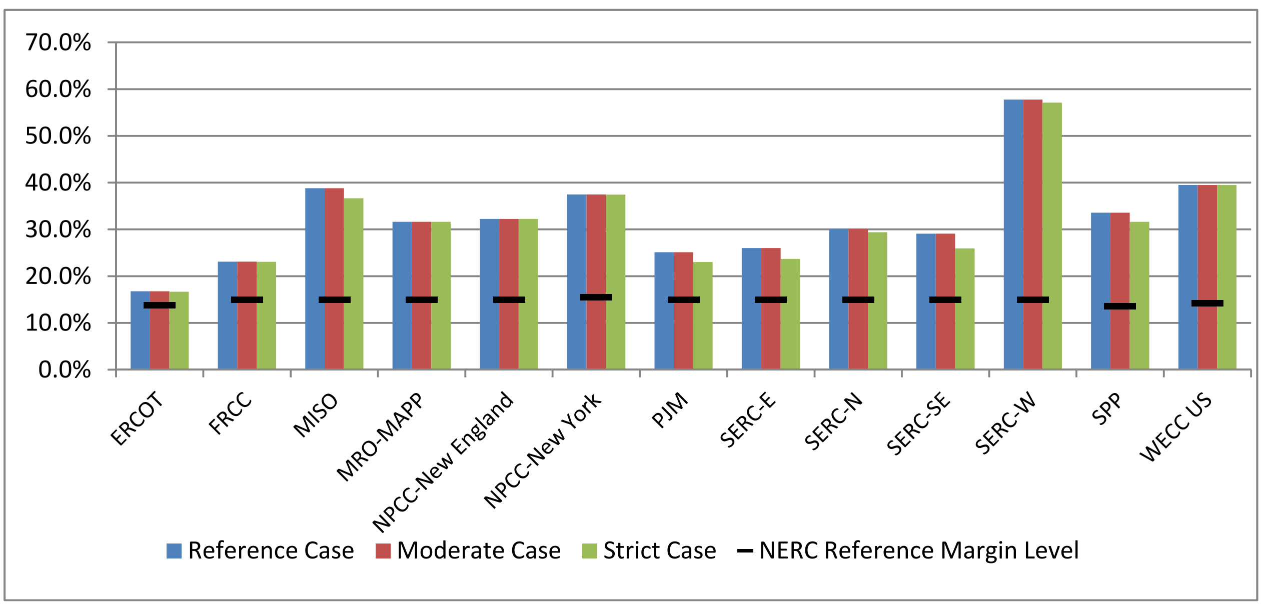


Figure 68: 2013 Peak Adjusted Potential Reserve Margin Scenario Impacts



Resource Adequacy Assessment Results: 2015

Table 40: 2015 Reference Case

	Total Internal Demand (MW)	Anticipated Capacity (MW)	Adjusted Potential (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	NERC Reference Margin Level (%)
United States						
ERCOT	71,910	79,682	82,575	10.8%	14.8%	13.8%
FRCC	49,278	60,761	61,288	23.3%	24.4%	15.0%
MISO	95,947	114,551	131,693	19.4%	37.3%	15.0%
MRO-MAPP	5,497	7,065	7,065	28.5%	28.5%	15.0%
NPCC-New England	29,380	32,886	36,936	11.9%	25.7%	15.0%
NPCC-New York	33,678	46,819	47,052	39.0%	39.7%	15.5%
PJM	166,506	200,990	206,142	20.7%	23.8%	15.0%
SERC-E	46,067	55,023	55,023	19.4%	19.4%	15.0%
SERC-N	48,437	58,570	59,133	20.9%	22.1%	15.0%
SERC-SE	53,378	64,256	67,342	20.4%	26.2%	15.0%
SERC-W	26,806	33,814	41,110	26.1%	53.4%	15.0%
SPP	55,556	69,176	73,834	24.5%	32.9%	13.6%
WECC US	149,723	205,844	209,719	37.5%	40.1%	14.2%
Total	**832,163**	**1,029,437**	**1,078,912**	**23.7%**	**29.7%**	**15.0%**

Table 41: 2015 Moderate Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	267	79,415	82,308	10.4%	14.5%
FRCC	176	60,585	61,112	22.9%	24.0%
MISO	1,629	112,922	130,064	17.7%	35.6%
MRO-MAPP	8	7,057	7,057	28.4%	28.4%
NPCC-New England	237	32,649	36,699	11.1%	24.9%
NPCC-New York	151	46,668	46,901	38.6%	39.3%
PJM	3,456	197,534	202,686	18.6%	21.7%
SERC-E	918	54,105	54,105	17.4%	17.4%
SERC-N	899	57,671	58,234	19.1%	20.2%
SERC-SE	1,675	62,581	65,667	17.2%	23.0%
SERC-W	95	33,719	41,015	25.8%	53.0%
SPP	385	68,791	73,448	23.8%	32.2%
WECC US	364	205,480	209,355	37.2%	39.8%
Total	**10,261**	**1,019,176**	**1,068,651**	**22.5%**	**28.4%**

Table 42: 2015 Strict Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	267	79,415	82,308	10.4%	14.5%
FRCC	1,748	59,013	59,540	19.8%	20.8%
MISO	4,982	109,569	126,711	14.2%	32.1%
MRO-MAPP	10	7,055	7,055	28.3%	28.3%
NPCC-New England	327	32,559	36,609	10.8%	24.6%
NPCC-New York	151	46,668	46,901	38.6%	39.3%
PJM	7,048	193,942	199,094	16.5%	19.6%
SERC-E	1,248	53,775	53,775	16.7%	16.7%
SERC-N	2,125	56,445	57,008	16.5%	17.7%
SERC-SE	3,206	61,050	64,136	14.4%	20.2%
SERC-W	360	33,454	40,750	24.8%	52.0%
SPP	700	68,476	73,134	23.3%	31.6%
WECC US	668	205,176	209,051	37.0%	39.6%
Total	**22,840**	**1,006,597**	**1,056,072**	**21.0%**	**26.9%**

Figure 69: 2015 Peak Anticipated Reserve Margin Scenario Impacts

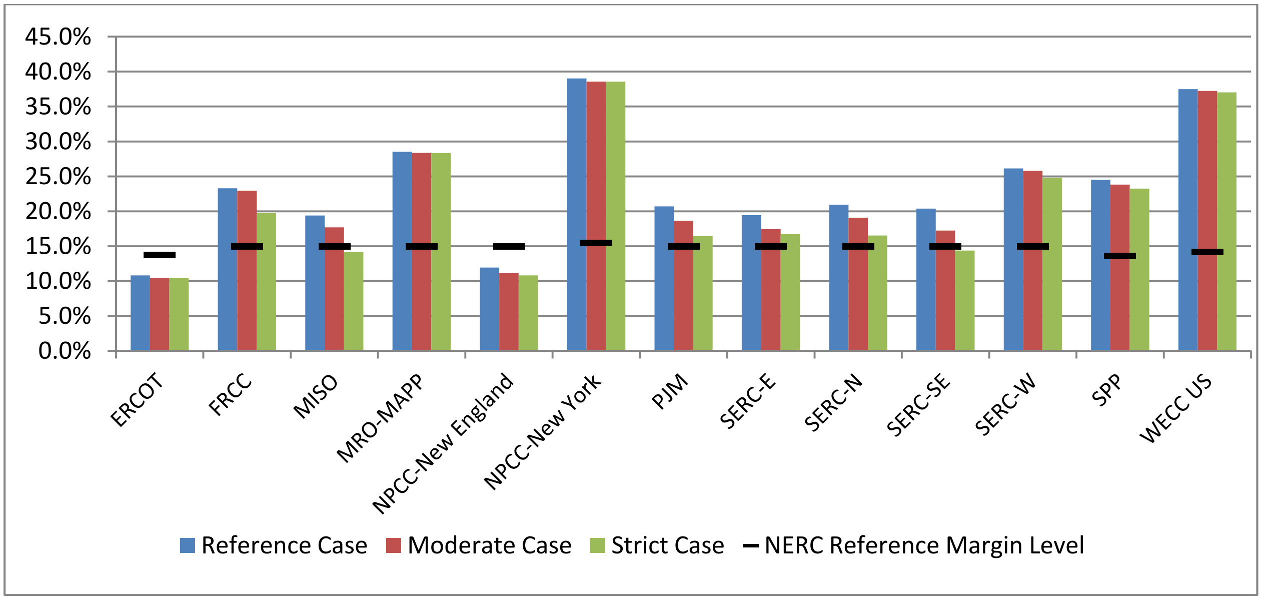
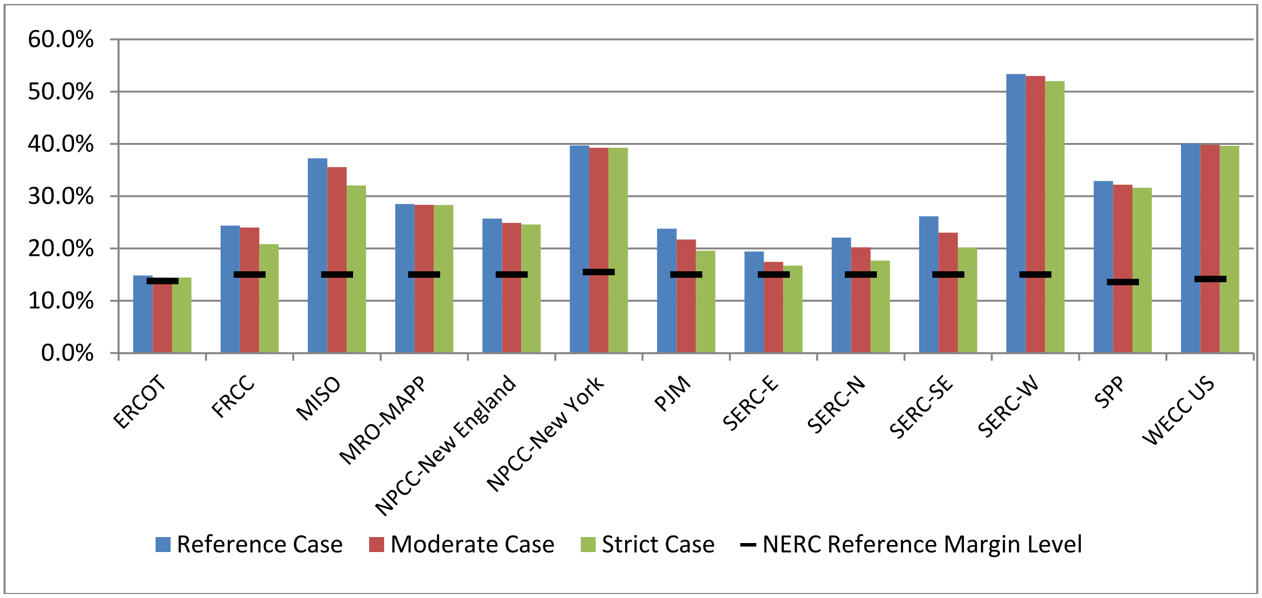


Figure 70: 2015 Peak Adjusted Potential Reserve Margin Scenario Impacts



Resource Adequacy Assessment Results: 2018

Table 43: 2018 Reference Case

	Total Internal Demand (MW)	Anticipated Capacity (MW)	Adjusted Potential (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)	NERC Reference Margin Level (%)
United States						
ERCOT	75,521	81,786	85,444	8.3%	13.1%	13.8%
FRCC	51,377	61,286	61,853	19.3%	20.4%	15.0%
MISO	98,110	114,633	131,775	16.8%	34.3%	15.0%
MRO-MAPP	5,776	7,211	7,211	24.8%	24.8%	15.0%
NPCC-New England	30,525	32,639	36,933	6.9%	21.0%	15.0%
NPCC-New York	34,190	46,819	47,073	36.9%	37.7%	15.5%
PJM	171,067	200,990	206,392	17.5%	20.6%	15.0%
SERC-E	47,636	56,104	56,104	17.8%	17.8%	15.0%
SERC-N	50,162	57,010	57,952	13.7%	15.5%	15.0%
SERC-SE	55,592	68,693	71,779	23.6%	29.1%	15.0%
SERC-W	27,806	31,491	40,751	13.3%	46.6%	15.0%
SPP	57,682	71,654	77,028	24.2%	33.5%	13.6%
WECC US	157,408	209,508	216,792	33.1%	37.7%	14.2%
Total	**862,851**	**1,039,825**	**1,097,086**	**20.5%**	**27.1%**	**15.0%**

Table 44: 2018 Moderate Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	5,451	76,335	79,993	1.1%	5.9%
FRCC	1,107	60,179	60,746	17.1%	18.2%
MISO	1,629	113,004	130,146	15.2%	32.7%
MRO-MAPP	8	7,203	7,203	24.7%	24.7%
NPCC-New England	5,138	27,501	31,795	-9.9%	4.2%
NPCC-New York	4,448	42,371	42,625	23.9%	24.7%
PJM	4,359	196,631	202,033	14.9%	18.1%
SERC-E	918	55,186	55,186	15.9%	15.9%
SERC-N	899	56,111	57,053	11.9%	13.7%
SERC-SE	1,912	66,781	69,867	20.1%	25.7%
SERC-W	95	31,396	40,656	12.9%	46.2%
SPP	385	71,269	76,643	23.6%	32.9%
WECC US	9,412	200,096	207,380	27.1%	31.7%
Total	**35,761**	**1,004,064**	**1,061,325**	**16.4%**	**23.0%**

Table 45: 2018 Strict Case

	Derates and Retirements (MW)	Anticipated Capacity (MW)	Adjusted Potential Capacity (MW)	Anticipated Reserve Margin (%)	Adjusted Potential Reserve Margin (%)
United States					
ERCOT	5,965	75,821	79,479	0.4%	5.2%
FRCC	2,679	58,607	59,174	14.1%	15.2%
MISO	5,406	109,227	126,369	11.3%	28.8%
MRO-MAPP	10	7,201	7,201	24.7%	24.7%
NPCC-New England	5,342	27,297	31,591	-10.6%	3.5%
NPCC-New York	4,637	42,182	42,436	23.4%	24.1%
PJM	10,682	190,308	195,710	11.2%	14.4%
SERC-E	1,332	54,772	54,772	15.0%	15.0%
SERC-N	2,125	54,885	55,827	9.4%	11.3%
SERC-SE	3,555	65,138	68,224	17.2%	22.7%
SERC-W	3,684	27,807	37,067	0.0%	33.3%
SPP	3,251	68,403	73,777	18.6%	27.9%
WECC US	10,489	199,019	206,303	26.4%	31.1%
Total	**59,157**	**980,668**	**1,037,929**	**13.7%**	**20.3%**

Figure 71: 2018 Peak Anticipated Reserve Margin Scenario Impacts

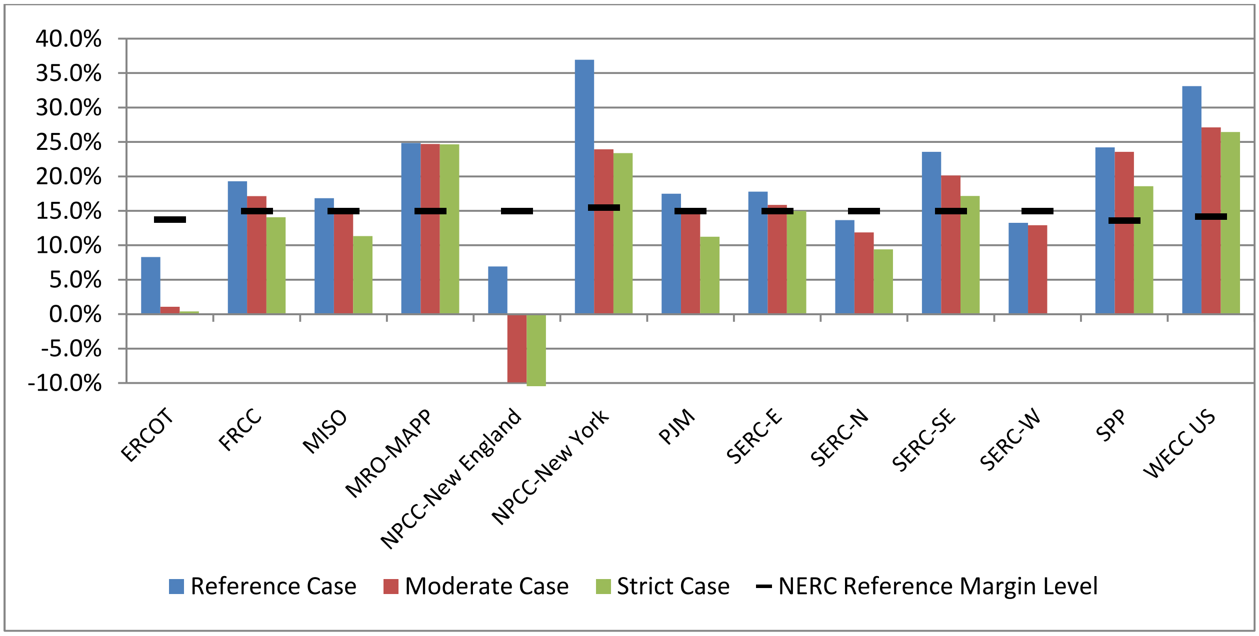
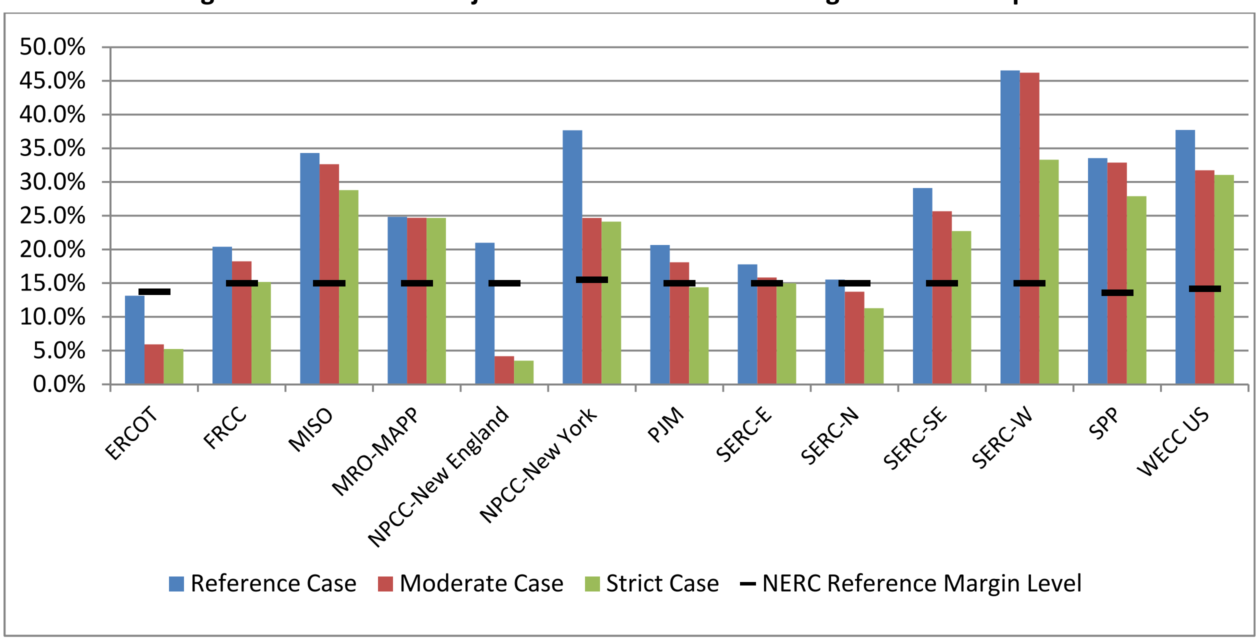


Figure 72: 2018 Peak Adjusted Potential Reserve Margin Scenario Impacts



Regional Assessment

For this update, NERC requested additional information from the Regional Entities. The Regions were requested to provide an update to NERC detailing the potential impacts caused by potential environmental regulations, identify the methods used to assess these impacts, and provide results of individual studies, if studies have been performed. Additionally, the Regional Entities identified potential issues unique to their area, measures in place, or being considered for implementation, to mitigate potential reliability concerns, and outline future activities planned to understand potential reliability impacts within the Region. The individual assessments are provided in the following sections. These regional assessments are not based on NERC's modeling results provided in this update, but instead, are summaries of their own assumptions and studies developed by each Regional Entity.

ERCOT

Potential or pending environmental regulations are studied, as they occur or are proposed, to determine the potential impact on system reliability. Regulations that could challenge the economic or operational viability of a generation resource are studied to determine the likelihood of that regulation to create resource adequacy issues within the ERCOT Region. For example, should a particular environmental regulation restrain or restrict coal-fired generating stations, ERCOT would perform an economic and transmission system study to determine the reliability implications to ERCOT given the proposed limitations to an existing resource or group of resources. One such study[141] has recently been completed to determine the reliability implications of the Clean Water Act (Section 316(b), Title I of the Clean Air Act (new emissions standards for hazardous air pollutants), Clean Air Transport Rule (CATR), and Coal Combustion Residuals (CCR) Disposal Regulations. A preliminary analysis of localized transmission system impacts included in the study indicates that the potential loss of 9,800 MWs of gas-fired generation would have impacts on transmission reliability in certain load center regions, likely requiring additional reactive devices and new import pathways into those regions. Redevelopment of existing generation sites in these areas with new generating units could reduce or delay the need for additional transmission infrastructure. In addition, ERCOT recently completed an assessment[142] of the proposed inclusion of Texas in the Cross-State Air Pollution Rule (replaces CATR). The assessment found that, if the rule is implemented as currently scheduled on January 1, 2012, then generators' current compliance plans indicate that 1,200 to 1,400 MW of generation would be unavailable year round and an additional 1,800 to 4,800 MW would be unavailable during the off-peak months. The unavailability of this generation would increase capacity insufficiency and the potential need for emergency actions including rotating outages, not only during the peak months but also during the off-peak months until retrofits or alternative resources are implemented.

FRCC

Entities may face challenges in scheduling the required overlapping maintenance outages of fossil-fired generating units. Resource adequacy in the near-term could also potentially be affected due to the lack of materials needed to retrofit existing resources. In addition, operational impacts associated with changes in dispatch patterns under certain conditions may occur. In order to address these concerns,

[141] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf
[142] http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf

entities within the FRCC Region are closely monitoring legislation related to EPA initiatives and evaluating potential options.

MRO

Recent environmental EPA rule proposals and the uncertainty around carbon control challenge industry's ability to finalize their plans. Ultimately, they could impact the configuration and operation of the bulk power system. These impacts may result in retirements of generation within the MRO-MISO footprint. If this occurs, the system within MRO-MISO may experience reliability impacts from the generation and transmission perspective.

To maintain compliance with environmental rules, capacity will be reduced from the system associated with both retrofits and retirements. In the MRO-MISO footprint, this will reduce the amount of existing capacity available to meet resource adequacy requirements. Transmission adequacy could also be impacted depending on what units retire from the bulk power system as a result of the rules. For example, a unit needed for transmission reliability and voltage support in a metro area may require additional transmission support to meet the reliability requirements on the system.

The current proposed rules will impact the coal-fired generation fleet located throughout the MRO-MISO footprint. From internal rule evaluation, the units most likely targeted for retirement are expected to be small, old units. However, all units that do not meet the proposed rule requirements will be impacted through retrofit costs and operational impacts of the new equipment. Carbon reduction requirements could put additional pressure on the coal-fired fleet in the MRO-MISO footprint and result in additional retirements. In fact, the uncertainty around future carbon reduction requirements may result in accelerated unit retirements rather than retrofit to reduce future cost risks.

Up to this point, the final and proposed EPA rules and the uncertainty around carbon reduction has not resulted in any current reliability issues. MRO and MISO are evaluating the potential impacts to be prepared to meet the stakeholders' needs as they determine whether units are to retire or retrofit. This will include evaluating impacts on resource and transmission adequacy. A proposed new capacity construct within MISO will also provide additional mitigation of reduced capacity on the system by allowing better management and integration of demand side resources and the management of the participation of intermittent resources.

NPCC

New England: ISO-NE routinely reviews the existing, pending, and promulgating environmental regulation for their potential impacts on existing or future capacity. Under the workloads associated with its Strategic Planning Initiative, ISO-NE has identified several regional power stations that may be retired due to the economics of compliance with pending state and Federal air and water regulations.

Emerging environmental regulations will very likely require large capital investments that are uneconomic for many older fossil-fueled resources. While the exact form and timing of the requirements remain uncertain, the stated intent of and requirements on the U.S. Environmental

Protection Agency (in certain instances through court order) means that there is a very high likelihood that substantial compliance investments will be required by owners of existing New England resources to continue operations. This could lead to a significant quantity of older generation choosing to retire rather than comply.

Compliance with a wide range of environmental requirements is expected to trigger capital investments beginning as soon as within the next two years and extending out for several years. Consequently, decisions on resource retirement and capacity pricing in light of these emerging requirements may affect current capacity auctions.

Currently, procedures are in place that would maintain system reliability. These include reliability agreements and out-of-merit unit commitment. However, appropriate enhancements to wholesale market design and system planning procedures could reduce the need for reliability agreements and out-of-merit unit commitment and dispatch, which would degrade the efficiency of market operations and/or prompt regulatory action. In addition, losing a significant quantity of coal, oil and nuclear capacity could further increase the areas dependence on natural gas-fired resources. The retirement of a significant quantity of capacity will almost certainly trigger a vigorous debate on whether to solve the resulting reliability problems with market resources or transmission. If all of the area's older oil units were to seek retirement, new capacity resources would be required to satisfy the Installed Capacity Requirement.

ISO-NE has initiated and is aggressively promoting a regional dialogue focused on solutions that can avert undesirable outcomes. ISO-NE has initiated a study to better quantify the implications of this issue. This analysis will complement the 2010 economic planning studies.

New York: Environmental initiatives that may affect generation resources may be driven by either or both the State and Federal programs. The 2009 New York State Energy Plan provides a long range vision and framework for New York's energy usage. The State's Department of Environmental Conservation (NYS DEC) annual publication of its regulatory agenda describes the new environmental initiatives that it will focus on during the coming year. The U.S. Environmental Protection Agency also publishes a similar report on its regulatory agenda.

There are numerous environmental initiatives that may impact the manner in which the existing generating fleet operates or require retrofitting environmental control technologies in order to comply with the new requirements. Several proposals have been identified for which impacts are expected to be widespread and likely to require significant capital investments in order to achieve the new standards.

RFC

Both PJM and MISO are independently reviewing the impacts of potential retirements within their RTOs. This assessment, which has been completed by Reliability*First* staff, reviews the moderate and Strict Cases for all four EPA regulations at the same time. Regional resource adequacy within Reliability*First* is

determined by assessing the resource adequacy of each RTO, and this regional retirement scenario determines the reserve margin impact of each RTO.

PJM and MISO are the RTOs that operate within the Reliability*First* footprint. Both stakeholders (PJM and MISO) have processes in place to review the reliability impacts of planned retirements prior to the scheduled retirement date. Each planned retirement is reviewed for any potential reliability issues, and any issues must first be mitigated before the planned retirement can occur. Since most generation owners do not announce their intent to retire a generating unit before it is necessary to get the RTO review, only a small number of units have been identified for future retirement through the PJM and MISO processes. In previous Long Term Reliability Assessments, the amount of unit retirements included in the assessment has been low.

Based on the data in this retirement assessment, PJM and MISO are projected to need additional resources or demand response by 2019 and 2018, respectively, under the moderate assumptions case. For the strict assumptions case, additional resources or demand response will be need as early as 2015 by MISO and in 2017 by PJM. The amount of retirements in this assessment, while exceeding recent experience, is a reasonable representation of the range of potential future generation retirements given the scope of the NERC special assessment and compliance to new EPA regulations. The amount of uncertainty in demand forecasts, future capacity additions and future generation retirements becomes greater with each additional year of the projected forecast. The inherent uncertainties in forecasting future reserve margins means that future retirement plans need to be more closely monitored in order to assess whether future reserve margin targets can be satisfied.

Recently, AEP has announced plans to retire nearly 6,000 MW of existing capacity to comply with these proposed regulations. Many of the proposed AEP capacity retirements are included in this future retirement assessment. As much as 1,900 MW of capacity identified by AEP as retirement candidates, were considered retrofitted in the NERC special assessment. The AEP announcement also indicated the repowering of several retired coal units with natural gas. This would effectively replace an additional 600 MW. The analysis in this assessment does not include any additional future capacity additions or repowering beyond what was already listed in the PJM and MISO generator interconnection queues. Modifying the PJM retirement assessment data for the AEP projected changes would reduce generation an additional 1,300 MW within PJM in the Moderate Case and 800 MW in the Strict Case. When these are added to those in the retirement scenario, PJM may need additional resources one year earlier.

SERC

Entities within SERC are currently in the process of evaluating the potential impacts of the Cross-State Air Pollution Rule (CSAPR) to meet the compliance obligations that begin January 1, 2012. The short timeframe to comply is a concern amongst entities, as there is the possibility of significant reductions in capacity factors for some generating units, which will require Must Run operations under certain system conditions. Implementation of CSAPR in 2012 will restrict dispatch flexibility, reducing options for addressing reliability challenges during adverse operating conditions such as weather extremes and significant unplanned events. The Utility MACT Rule that EPA plans to issue in December 2011, will initiate a three year implementation period requiring an aggressive construction schedule in SERC to

install transmission reinforcements, generation additions, and environmental controls retrofits. Transmission and generation outage coordination will be significantly challenged. CSAPR limits in interstate allowance trading may also impact the ability to obtain assistance from neighboring areas.

With Utility MACT compliance requirements in 2015, severe reductions in capacity could result depending upon the levels of environmental controls required by the final rule and the ability of entities to retire/replace generation and install controls within the 3 year compliance deadline. In many areas of SERC, utilities are working internally and with consultants to gain a better understanding of the EPA rules and to assess the costs and scheduling of implementing various pollution control measures or generation alternatives. Efforts are ongoing at this time as entities strive to develop strategies to comply based upon the thresholds provided in EPA's proposed rules. However, these strategies will not be finalized until future regulations are released.

The data below represents additional information collected in August 2011, as requested by NERC. Fluctuations in capacity reflect the changes that entities have made for the 2011 annual peak data reported from February to September 2011. Announced retirements and station loads due to retrofits are reflected in the values of the SERC 2011 Long-Term Reliability Assessment reference case. However, many generation retirement decisions will not be made until the final Utility MACT rules have been issued and assessed. These uncertain retirement decisions are not included in the 2011 reference case because resource plans typically reflect only existing rules and regulations and do not include resource impacts related to potential requirements.

Flue Gas Desulfurization Scrubbers (FGD) and Select Catalytic Reduction (SCR) controls have already been installed on many units to address emission concerns. Recent SERC entities' responses indicate that approximately 129 units have been retrofitted with FGDs and/or SCRs to comply with EPA regulations. It was reported that 24 retrofit projects are underway or awaiting regulatory approval. Of these projects, 5 (1,563 MW) are scheduled to be completed by the summer of 2012. More than 52 units (~ 8,000 MW) require additional environmental controls for compliance. Many entities note that these are preliminary projections of the projects needed and will continue to evaluate the remaining uncontrolled units to determine which, if any, of the units will be retrofitted with FGD systems and SCRs. Decisions to retrofit, retire, convert to gas operation, or replace those units will be made when future EPA Regulations' criteria and implementation timelines become more transparent. In many cases, transmission enhancements and gas pipeline infrastructure to support these decisions cannot be accomplished during a three year implementation period.
Depending upon the emissions levels established by the final Utility MACT rules, additional controls (such as baghouses) may need to be added to units that are already equipped with FGDs and SCRs. It is unknown whether units which have already installed FGDs and SCRs would be permitted to operate beyond 2015 if additional required controls, such as baghouses, cannot be completed in time.

Units to be retired within the areas are also uncertain at this time. Initial reports show that approximately 10,250 MW (58 units) of coal-fired generation will be retired within the SERC Region to be compliant with the recent rules. Although entities feel it is very early in the process to determine the impacts of the rules, their analyses consider all current, proposed, and expected rules such as: the Cross-

State Air Pollution Rule (or its predecessors CAIR/the proposed Transport Rule), Clean Air Visibility Rule (CAVR), the proposed Electric Generating Unit Maximum Achievable Control Technology (Utility MACT) rule, the proposed 316(b) rule for cooling water intake structures, the proposed Coal Combustion Residuals (CCR) rule, and expected regulation of Greenhouse Gases (GHGs), along with a range of potential fuel prices. State regulators are also involved in the process to help entities establish plans to replace any capacity that may be lost, and approve retirements and retrofits that are needed. Significant amounts of potential generation capacity retirements have not yet been provided for inclusion in the 2011 Long-Term Reliability Assessment reference case because many state resource plans do not reflect the potential impacts of proposed EPA rules.

Recent SERC entities' analyses shows that approximately 6,200 MW or more of coal- and oil-fired generation is expected to be converted to other fuels, such as natural gas. Some capacity will be permanently retired, whereas other capacity may be unable to operate pending additional environmental controls or gas conversion infrastructure. Consideration of various resource selections in the assessment process may require transmission enhancements and take into account construction schedules. In general, many entities are uncertain of specific sites for additional capacity, if needed, at this time. Ongoing nuclear, demand-side management, biomass and renewable resource projects are also being implemented. New resources and programs would require additional time to design, obtain regulatory approval, implement and gain reasonable scale.

SERC entities are also assessing operational reliability impacts related to changes in the generation fleet makeup and operating parameters. These reliability assessments include revisions to System Restoration Plans (Blackstart), gas pipeline contingency studies, multiple unit outage contingencies related to common environmental controls, stability and voltage security impacts, fault current studies, and others.

Entities within SERC are taking various steps to assess the impacts of the EPA rules. Consultants have been hired to assess entity costs, studies are in progress to develop plans for generation redispatch, and operational procedures are being revised to compensate for alternative generation mixes. These tasks reflect SERC entity efforts to find strategies to achieve the lowest reasonable operational cost consistent with the provision of adequate and reliable electric service, while complying with environmental regulations. Entities are concerned that the timeframe to become compliant with the new rules is not sufficient to complete the many retrofit projects needed on existing units. Some deem the impact of these new rules will jeopardize reliability because: 1) units without all of the required environmental control retrofits may not be allowed to operate, 2) replacement generation or infrastructure upgrades for fuel switches may not be complete, and 3) final decisions regarding whether to retrofit, retire and replace, or change the fuel supply of units to natural gas will not be made until all the rules are final.

SPP

Due to the EPA's adoption of the CSAPR in July 2011, the SPP RTO and its members have not had time to fully assess the Rule's impacts to individual systems or to the RTO as a whole. The SPP EPA Study did not originally include the final CSAPR impacts, but the SPP RTO began working on a 2012 assessment of the CSAPR in September 2011 (SPP CSAPR Study). The study began with a review of the EPA CSAPR Model

results which showed that 10.7 GWs of generating capacity in the SPP RTO footprint would not be deployed in 2012.[143] Further analysis to account for capacity that is not expected to be needed for peak yielded a net impact of CSAPR of 5.4 GWs from 48 units that would be unavailable across the 2012 Summer Peak. Additionally, the SPP CSAPR Study showed a shift in the generation from larger plants to smaller plants. Preliminary results of the SPP CSAPR study show that many overloads greater than 120 percent of a facility's emergency ratings were found under N-1 conditions. Furthermore, due to the non-deployment of major units in some areas there were voltage issues below 85 percent, with two-thirds of the voltage issues occurring on 115kV lines, and the remaining one-third on 69 kV lines. However, the reliability impacts have not yet been fully determined and work continues on the SPP CSAPR Study.[144]

WECC

On May 4, 2010, California's State Water Resources Control Board (SWRCB) adopted a policy regarding once-through cooling used at electricity-producing power plants in California. *Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*[145] provides clear and consistent standards for implementing the Clean Water Act for electricity-producing power plants, which operate under National Pollutant Discharge Elimination System (NPDES) permits issued by California's nine Regional Water Boards. In developing the policy, the State Water Board staff met regularly with representatives from the agencies that oversee the electricity supply grid (including the California Energy Commission, the California Public Utilities Commission, and the California Independent System Operator) to develop realistic and phased-in implementation plans and schedules. Under the draft policy, the State Water Board will continue to work with the energy agencies to ensure that the compliance schedules assure electric supply reliability. Information regarding the policy, a proposed policy amendment and the compliance plans filed by the owners of the 19 plants (21,000 MW) is available on the SWRCB website.[146] The current fluid nature of compliance plans combined with long-term plans for California's resource additions has created problematic issues in producing a detailed reliability assessment. Despite these circumstances, WECC staff is currently not aware of planned individual unit retirements that are expected to have a significant impact on reliability.

[143] The EPA Model deployed generating units based on a unit retro-fit analysis instead of on a system reliability basis. EPA CSAPR Model

[144] These results are based on EPA CSAPR Model unit deployments rather than individual SPP Member plans for their generation assets.

[145] http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/powerplants/alamitos/docs/ags_ip2011.pdf.

[146] SWRCB Once-Through Cooling Information: http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/.

Conclusions

While none of the EPA rules are final, and thus their impact cannot be completely measured, the results of this update show a measurable impact to Planning Reserve Margins should the four potential EPA rules NERC has examined be implemented as assumed in this update. 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 impacted in certain Assessment Areas, driving potential resource adequacy concerns. Additionally, considerable operational challenges will exist in managing, coordinating, and scheduling an industry-wide environmental control retrofit effort, along with the need to add system reinforcement. The update results along with information provided by NERC stakeholders and industry representatives revolve around five key conclusions:

1. **__Timing__** – Compliance deadlines will challenge the electric industry's planning horizons, existing planning processes and typical construction schedules. Transmission lines, power plants, and environmental control retrofits are often planned and constructed over a long period of time. Successful implementation of the proposed EPA rules will be highly dependent on the amount of time the industry will be given to comply with future environmental regulations and that tools are in place within a timely manner to support the industry's transition given the large number of units that must be retrofit.

2. **__Regionality__** – The fuel-mix differs greatly across the country. Each area will face different dynamics due to the types of generators as well as the types of regulatory environments within a given area (*i.e.,* deregulated markets, regulated utility service areas, state regulations). State decisions could greatly influence the cumulative impacts.

3. **__Outage Coordination__** – Given the window for compliance, many affected units may need to take long-term maintenance outages concurrently. The need to take multiple units out-of-service on extended scheduled outages can exacerbate resource adequacy concerns and reduce needed flexibility, even during off-peak periods. Outage coordination must be a priority to avoid resource adequacy concerns.

4. **__Transmission and Operational Issues__** – The retirement of larger and/or strategically situated generating units will cause changes to the power flows and stability dynamics of the bulk power system. These changing characteristics will require enhancements to the interconnected transmission systems to provide reactive and voltage support, address thermal constraints, and provide for system stability. Based on information gathered from stakeholders and the Regional

Entities, these issues may cause some reliability concerns unless the transmission system is reconfigured. In some cases, these reliability issues can result in violations of NERC Reliability Standards and, therefore, pose a threat to reliability if they are not addressed.

As more gas-fired generation is incorporated into a given system gas and electric interdependency issues must also be addressed. More gas-fired generation will require additional gas pipeline infrastructure, increased coordination with pipeline operators, and developing operational strategies to minimize potential fuel delivery issues. These issues were highlighted in a recent NERC report on gas and electric interdependencies.

5. **<u>Uncertainty</u>** – A major concern among planning entities and regulatory bodies, such as NERC, is the lack of certainty both on the generating supply side and from EPA. Planning Authorities disconnected from the owning/operating functions of generation do not have the visibility needed to accurately model these potentially significant system changes. For example, rules within the ISO/RTO market structures allow generators to request retirement within 90 days of the requested retirement date. Even with facilities which are not being retired, Planning Authorities and grid operators may not be aware of significant changes in plant operating parameters and new common contingencies. The lack of information and data sharing, and therefore sufficient planning, causes concern.

   Uncertainty remains within the regulatory policy making process as to what the final requirements will be on generators. While many of the rules have been proposed, with some already finalized, the industry is forced to continue to make assumptions on what the final rules will require. While the proposed rules give a good representation, final rules can be quite different (*e.g.,* as seen in Texas/ERCOT). Increasing the certainty with respect to the timing and requirements of the regulations would promote timely and sound engineering planning to support the implementation of these rules in an orderly and predictable manner.

   Furthermore, as rules are finalized and more flexibility is needed to reliably operate the bulk power system, an efficient and systematic process is needed to grant waivers and extensions for generators that are vital to the grid (*i.e.,* critical reliability units, black-start).

KEY FINDINGS - ENVIRONMENTAL REGULATIONS

Existing and proposed environmental regulations in the U.S. may significantly affect bulk power system reliability depending on the scope and timing of the rule implementation and the mechanisms in place to preserve reliability.

Recommendations

The following recommendations are pertinent to Federal and state regulators, the electric industry, as well as NERC, and supplement the 2010 NERC EPA Assessment:

Regulators:

- The Electric Reliability Organization's Reliability Standards and Regional Criteria must be met at all times to ensure reliable operation and planning of the bulk power system. Based on the results of this study, more time is needed in certain areas to ensure resource adequacy and local reliability requirements can be addressed during the transition period. EPA, FERC, DOE and state utility regulators, working together and separately, should employ the array of tools at their disposal and their regulatory authority to preserve bulk power system reliability, including the deferral of compliance targets and granting extensions where there is a demonstrated reliability need. Coordination among Federal agencies is necessary to ensure the industry is not forced to violate one regulation to meet another.

Industry:

- Industry participants must meet NERC's Reliability Standards to ensure reliability and as they address compliance requirements of the EPA regulations. They should employ available tools and processes to ensure that bulk power system reliability is maintained through any resource transition. Toward that end, regional wholesale competitive market operators should ensure capacity markets are functioning effectively to support the development of new replacement capacity where needed. Similarly, stakeholders in areas without organized markets should work to ensure that investments are made to retrofit or replace capacity that will be affected by forthcoming EPA regulations. Additionally, affected unit owners that may be disconnected from wide-area planning functions (*e.g.,* generator owners operating in an ISO/RTO), should provide Planning Authorities timely and accurate information about the compliance plans for their units in order to adequately measure.

- Perhaps one of the most significant risk factors will be taking the existing units out for maintenance to install the needed environmental control equipment. Outages for retrofits, new generation, and required transmission must be coordinated to ensure continued bulk power system reliability not only during peak periods, but during off-peak shoulder months when more scheduled outages are expected to occur.

NERC:

- NERC should continue to assess the implications of the EPA regulations as greater certainty emerges around industry obligations, technologies, timelines, and targets. Further, NERC should lead industry's effort and response to measure resource adequacy implications along with impacts to operating reliability (e.g., deliverability, stability, localized issues, outage scheduling, operating procedures, and industry coordination) resulting from proposed and pending EPA regulations. NERC should leverage the expertise of the Planning Authorities to assess the local system conditions that could degrade reliability, review plans for meeting environmental regulations as well as NERC Reliability Standards, and submit recommendations to FERC on behalf of the industry.

Additional Background Information

Table 46: Projected Incremental Capacity Losses through 2013 by Regulation – Moderate Case

	Moderate Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 47: Projected Incremental Capacity Losses through 2013 by Regulation – Strict Case

	Strict Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	-	-	-	-	67	-	-	-	76
FRCC	-	-	-	-	-	8	-	-	-	13
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	12
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	851	212	-	-	1,679	387
PJM	-	-	-	-	1,487	81	-	-	3,173	225
SERC-N	-	-	-	-	65	44	-	-	264	61
SERC-W	-	-	-	-	-	57	-	-	75	100
SERC-SE	-	-	-	-	157	8	-	-	1,555	72
SERC-E	-	-	-	-	262	-	-	-	1,018	14
SPP	-	-	-	-	26	136	-	-	811	256
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	2,847	612	-	-	8,574	1,217
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 48: Projected Incremental Capacity Losses through 2015 by Regulation – Moderate Case

	Moderate Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	9	-	99	-	267
FRCC	-	77	-	-	-	-	628	65	-	176
ISO-NE	-	32	-	-	-	-	-	22	144	93
NYISO	-	51	-	-	-	-	74	16	74	77
MAPP	-	-	-	-	-	-	-	8	-	8
MISO	-	-	-	-	-	10	1,110	508	1,110	519
PJM	-	8	-	-	-	16	2,650	536	2,850	606
SERC-N	-	-	-	-	-	12	262	168	724	175
SERC-W	-	-	-	-	-	-	-	95	-	95
SERC-SE	10	47	-	-	-	4	699	179	1,358	318
SERC-E	-	-	-	-	-	-	656	112	808	110
SPP	-	-	-	-	-	1	187	197	187	198
CAL-N	-	1	-	-	-	-	15	1	15	4
CAL-S	-	3	-	-	-	-	83	1	83	4
Basin	-	-	-	-	-	-	39	29	39	29
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	-	-	-	-	-	-	99	23	89	23
NWPP	-	-	-	-	-	-	12	34	12	34
TOTAL	10	377	-	-	-	53	6,513	2,127	7,491	2,770
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 49: Projected Incremental Capacity Losses through 2015 by Regulation – Strict Case

	Strict Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	50	-	99	-	267
FRCC	-	6	-	-	-	4	1,254	60	1,592	156
ISO-NE	-	-	-	-	-	-	144	19	239	88
NYISO	-	22	-	-	-	9	74	16	74	77
MAPP	-	2	0	-	-	-	-	8	-	10
MISO	44	799	0	-	928	257	1,297	506	3,583	1,400
PJM	5	377	-	-	1,506	168	4,016	513	5,725	1,323
SERC-N	-	214	0	-	65	59	547	164	1,690	435
SERC-W	-	-	-	-	0.02	57	0.02	95	265	95
SERC-SE	10	-	-	-	478	60	1,181	170	2,942	265
SERC-E	-	-	-	-	490	11	903	108	945	303
SPP	-	196	-	-	77	165	187	197	285	415
CAL-N	15	-	-	-	-	-	15	1	67	2
CAL-S	-	-	-	-	-	-	83	1	184	-
Basin	39	6	-	-	-	-	39	29	39	35
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	18	32	-	-	-	-	143	22	203	53
NWPP	-	6	-	-	-	-	12	34	12	40
TOTAL	130	1,817	0.09	-	3,544	841	9,893	2,078	17,844	4,996
Oil/Gas-Steam Turbine Units										
ERCOT	-	-	-	-	-	-	-	-	-	-
FRCC	-	-	-	-	-	-	-	-	-	-
ISO-NE	-	-	-	-	-	-	-	-	-	-
NYISO	-	-	-	-	-	-	-	-	-	-
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	-	-	-	-	-	-	-	-	-	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	-	-	-	-	-	-	-	-	-	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	-	-	-	-	-	-	-	-	-	-
CAL-S	-	-	-	-	-	-	-	-	-	-
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	-	-	-	-	-	-	-	-	-	-
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	-	-	-	-	-	-	-	-	-	-

Table 50: Projected Incremental Capacity Losses through 2018 by Regulation – Moderate Case

	Moderate Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	9	-	99	-	267
FRCC	-	107	-	-	-	-	628	65	-	176
ISO-NE	-	79	-	-	-	-	-	22	144	93
NYISO	74	60	-	-	-	-	74	16	74	77
MAPP	-	-	-	-	-	-	-	8	-	8
MISO	-	-	96	-	-	10	1,110	508	1,110	519
PJM	209	67	-	-	-	16	2,650	536	2,850	606
SERC-N	-	-	135	-	-	12	262	168	724	175
SERC-W	-	-	-	-	-	-	-	95		95
SERC-SE	10	179	-	-	-	4	699	179	1,358	318
SERC-E	-	-	-	-	-	-	656	112	808	110
SPP	-	-	-	-	-	1	187	197	187	198
CAL-N	15	3	-	-	-	-	15	1	15	4
CAL-S	83	3	-	-	-	-	83	1	83	4
Basin	-	-	-	-	-	-	39	29	39	29
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	-	-	-	-	-	-	99	23	89	23
NWPP	-	-	-	-	-	-	12	34	12	34
TOTAL	390	657	231	-	-	53	6,513	2,127	7,491	2,770
Oil/Gas-Steam Turbine Units										
ERCOT	5,065	119	-	-	-	-	-	-	5,065	119
FRCC	904	27	-	-	-	-	-	-	904	27
ISO-NE	4,898	4	-	-	-	-	-	-	4,898	4
NYISO	4,096	201	-	-	-	-	-	-	4,096	201
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	-	-	-	-	-	-	-	-	-	-
PJM	903	-	-	-	-	-	-	-	903	-
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	-	-	-	-	-	-	-	-	-	-
SERC-SE	237	-	-	-	-	-	-	-	237	-
SERC-E	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	-	-	-	-	-	-
CAL-N	2,138	-	-	-	-	-	-	-	2,138	-
CAL-S	6,439	48	-	-	-	-	-	-	6,439	48
Basin	-	-	-	-	-	-	-	-	-	-
Desert SW	418	5	-	-	-	-	-	-	418	5
RMPA	-	-	-	-	-	-	-	-	-	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	25,097	404	-	-	-	-	-	-	25,097	404

Table 51: Projected Incremental Capacity Losses through 2018 by Regulation – Strict Case

	Strict Case									
	Section 316 (b)		Coal Ash Ponds		CSAPR		Air Toxics		Combined	
	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate	Retired	Derate
Coal Units										
ERCOT	-	159	-	-	-	50	-	99	-	267
FRCC	-	107	628	-	-	4	1,254	60	1,592	156
ISO-NE	-	79	-	-	-	-	144	19	239	88
NYISO	74	60	-	-	-	9	74	16	74	77
MAPP	-	2	-	-	-	-	-	8	-	10
MISO	714	987	109	-	928	257	1,297	506	3,583	1,400
PJM	1,334	949	-	-	1,506	168	4,016	513	5,725	1,323
SERC-N	200	308	135	-	65	59	547	164	1,690	435
SERC-W	-	11	-	-	-	57	-	95	265	95
SERC-SE	120	176	120	-	478	60	1,181	170	2,942	265
SERC-E	143	204	-	-	490	11	903	108	945	303
SPP	74	216	51	-	77	165	187	197	285	415
CAL-N	15	3	-	-	-	-	15	1	67	2
CAL-S	83	3	-	-	-	-	83	1	184	-
Basin	39	6	-	-	-	-	39	29	39	35
Desert SW	-	-	-	-	-	-	-	34	-	34
RMPA	43	33	-	-	-	-	143	22	203	53
NWPP	12	6	-	-	-	-	12	34	12	40
TOTAL	2,850	3,308	1,043	-	3,544	841	9,893	2,078	17,844	4,996
Oil/Gas-Steam Turbine Units										
ERCOT	5,593	105	-	-	-	-	-	-	5,593	105
FRCC	904	27	-	-	-	-	-	-	904	27
ISO-NE	5,015	-	-	-	-	-	-	-	5,015	-
NYISO	4,291	195	-	-	-	-	-	-	4,291	195
MAPP	-	-	-	-	-	-	-	-	-	-
MISO	424	-	-	-	-	-	-	-	424	-
PJM	3,632	2	-	-	-	-	-	-	3,632	2
SERC-N	-	-	-	-	-	-	-	-	-	-
SERC-W	3,134	190	-	-	-	-	-	-	3,134	190
SERC-SE	349	-	-	-	-	-	-	-	349	-
SERC-E	84	-	-	-	-	-	-	-	84	-
SPP	2,523	29	-	-	-	-	-	-	2,523	29
CAL-N	2,138	-	-	-	-	-	-	-	2,138	-
CAL-S	6,924	36	-	-	-	-	-	-	6,924	36
Basin	113	-	-	-	-	1	-	-	113	1
Desert SW	523	2	-	-	-	-	-	-	523	2
RMPA	84	-	-	-	-	-	-	-	84	-
NWPP	-	-	-	-	-	-	-	-	-	-
TOTAL	35,730	587	-	-	-	1	-	-	35,730	588

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