October 2008

Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generation Units

U.S. Department of Energy

Office of Electricity Delivery and Energy Reliability

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Executive Summary

The U.S. Senate Committee on Appropriations, Subcommittee on Energy and Water Development, requested the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE or Department) to examine the impacts on electricity reliability of requiring existing steam generators using once-through cooling systems to replace those systems with closed-cycle cooling towers to condense and to cool the steam after its use in the generation of electricity.

DOE provided the North American Electric Reliability Corporation (NERC) with a list of steam generation units that would be required to retrofit to cooling towers. [1] DOE requested NERC to model the reliability impacts of the cooling tower mandate using certain assumptions (*see* Chapter 3). NERC provided DOE with its results in a white paper entitled, "2008-2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generating Facilities, (NERC White Paper), which is provided as an Appendix to this analysis.

In its white paper, NERC concludes that once the deadline for the cooling tower retrofits has passed, the generation losses resulting from the requirement would exacerbate a potential decline in electric generation reserve margins that are needed to ensure reliable delivery of electricity. Generally, the goal for NERC regions is to have the equivalent of between 10.5 and 13 percent of their peak generation demand available to meet contingencies. Assuming only planned generation is built, NERC projects overall capacity reserve margins to fall to 14.7 percent by 2015. However, upon analyzing the impact of a cooling tower mandate, NERC projects that, "U.S. resource margins drop from 14.7 percent to 10.4 percent when both the retired units and auxiliary loads due to retrofitting were compared to the *Reference Case*." (NERC White Paper, p. 4)

Based on the best available data, the loss of generation capacity due to reduced operational efficiency in combination with the early retirement of facilities that either cannot or choose not to retrofit may jeopardize the ability of California, New York, and New England to meet peak demand for electricity. In addition, one could reasonably expect that the capacity margin reduction would further aggravate transmission congestion in the Mid-Atlantic Area National Interest Electric Transmission Corridor.

[1] In preparation of this analysis, DOE's Office of Electricity Delivery and Energy Reliability (OE) worked with staff in DOE's Office of Fossil Energy in the Systems, Analysis, and Policy Group at the National Energy Technology Laboratory (NETL).

Summary

The U.S. Senate Committee on Appropriations, Subcommittee on Energy and Water Development, requested the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE or Department) to examine the impacts on electricity reliability of a potential rule under section 316(b) of the Federal Water Pollution Control Act (Clean Water Act) that would require existing steam generators using once-through-cooling systems to replace those systems with closed-cycle cooling towers to condense and to cool the steam after its use in the generation of electricity.

Section 316(b) was enacted to provide for the regulation of thermal discharges to the Nation's surface waters. On January 25, 2007, the U.S. Circuit Court of Appeals for the Second Circuit remanded several provisions of the Phase II Final Rule promulgated by the Environmental Protection Agency (EPA). The United States Supreme Court has agreed to hear the appeal of the circuit court's ruling and oral argument is scheduled for later in this year. [2] One potential outcome could require all existing power plants withdrawing 50 million gallons of water or more per day and using at least 25 percent of the water withdrawn for cooling purposes to comply with new requirements to minimize impingement and entrainment of larval fish and other aquatic organisms. Among the alternatives advocated is the replacement of existing once-through-cooling systems with cooling towers. This paper evaluates the potential impact of such a requirement on electric reliability.

DOE provided the North American Electric Reliability Corporation (NERC) with a list of steam generation units that would be required to retrofit to cooling towers. [3] DOE requested NERC to model the reliability impacts of the cooling tower mandate using certain assumptions (*see* Chapter 3). NERC provided DOE with its results in a white paper entitled, "2008-2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generating Facilities" (NERC White Paper), which is provided as an appendix to this analysis.

The Nation's electricity industry faces major challenges during the next 15 years to keep adequate reserve capacity margins of electricity generation available to meet peak demand growth, even if that peak demand growth is dampened by initiatives focused on demand-response, improved technology, and energy efficiency. Nevertheless, electricity operators must plan to provide adequate generation capacity during periods of peak electricity demand, with a margin of additional capacity ready for contingencies, such as an unexpected generation plant shutdown. These capacity requirements are expected to grow despite increasing participation of consumers and utilities in demand response

[2] *See* Entergy Corporation v. Environmental Protection Agency, et al., No.07-588, April 14, 2008.

[3] In preparation of this analysis, DOE's Office of Electricity Delivery and Energy Reliability (OE) worked with staff in DOE's Office of Fossil Energy in the Systems, Analysis, and Policy Group at the National Energy Technology Laboratory (NETL).

programs and investments in energy efficiency. According to data collected by the NERC, average peak demand during the summer is expected to increase by over 135,000 megawatts (MW) or 17.7 percent by 2017, while committed resources[4] are projected to grow by only 77,000 MW.[5]

Over half of the existing fleet of thermoelectric power plants in the United States is estimated to be equipped with once-through cooling systems (*see* Table 3-1, p. 17.). This represents 385 existing power plants that could be affected by 316(b) Phase II regulations. By far the majority of the affected plants (roughly 70 percent) are baseload steam plants, predominantly coal and nuclear facilities. The remaining 30 percent are mostly older, less efficient oil- and gas-fired steam facilities.

Retrofitting a facility that was originally designed for once-through cooling to a recirculating cooling system will result in reduced power output from the additional equipment that needs to be run (ancillary load loss), such as pumps and fans, and from the loss of efficiency because the cooling water is generally warmer coming back from a cooling tower than it is from the body of water used by a once-through cooling system. While the reduced power output (energy penalty) from both types of losses is estimated to be less than two percent of the average net power output of the facility, when summer ambient conditions are at their worst (i.e., hot and humid, so that the cooling tower water is at its warmest), the reduced output increases, approaching as much as 4 percent of the facility's net output. Accordingly, the energy penalty of retrofitting to a recirculating cooling system is the greatest when the power grid is strained the most, during periods of peak summer electric demand. The loss of efficiency and generation capacity means that less electricity is available to meet demand or to serve as reliable reserve capacity.

Nuclear plants would be particularly impacted by a cooling tower mandate because re-evaluation of the nuclear plant safety basis and Nuclear Regulatory Commission (NRC) licensing amendments would be required for existing nuclear reactors to comply with such a rule. This is in addition to the engineering, construction, outage, and power replacement impacts and loss of revenue similar to large, baseload coal plants. The licensing impact would be determined by the complexity of necessary design changes to safety and non-safety cooling systems, preparation of required license application documentation and supporting analyses, submission of the license amendment package, and the review and approval by the U.S. Nuclear Regulatory Commission. The potential for significant negative economic impact could influence utilities to not pursue further license renewals based on unfavorable financial returns, further reducing electricity grid operating margins. During Fiscal Year 2009, the Department of Energy will work with NRC and industry to better characterize the scope and impact of such a change to an operating nuclear plant.

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[4] Committed resources include generating capacity resources that exist, are planned, or under construction. These resources are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.
[5] NERC *2007 Long-Term Reliability Assessment*. (NERC further states that, "a major driver of the uncertain or inadequate capacity margins is the industry's relatively recent shorter-term approach to resource planning and acquisition, relying heavily on unspecified, undeveloped, and/or uncommitted resources to meet projected demand."), p. 11 (October 2007).

In its white paper, NERC concludes that once the deadline for the cooling tower retrofits has passed, the generation losses resulting from the requirement would exacerbate a potential decline in electric generation reserve margins that are needed to ensure reliable delivery of electricity. Generally, the goal for NERC regions is to have the equivalent of between 10.5 and 13 percent of their peak generation demand available to meet contingencies. Assuming only planned generation is built, NERC projects overall capacity reserve margins to fall to 14.7 percent by 2015. However, upon analyzing the impact of a cooling tower mandate, NERC projects that, "U.S. resource margins drop from 14.7 percent to 10.4 percent when both the retired units and auxiliary loads due to retrofitting were compared to the *Reference Case*." (NERC White Paper, p. 4)

Absent a plant-by-plant investigation, this analysis is limited in its ability to project which individual generating units subject to a retrofit mandate would not be retrofitted for either economic or siting reasons. Generally, older units may not have sufficient useful operating life remaining to recover the retrofit investment. Also, less efficient generation facilities may not be operated enough hours of the year (i.e., have a low "capacity factor") to justify the retrofit investment.

Similarly, this analysis is not able to make quantitative conclusions on the location and number of facilities that do not have the physical space or could not obtain the requisite permits to construct cooling towers. For example, the 483 MW coal-fired Mirant Potomac River Power Plant, located next to the flight path into Ronald Reagan Washington National Airport and which supplies much of downtown Washington, D.C., would be unlikely to be able to install cooling towers due to both space and permit restrictions.

For this analysis, DOE used capacity factor (the percentage of the time a plant is actually generating) as a proxy for economic and permitting viability of facilities considering a cooling tower retrofit. The DOE analysis assumed a range of potential plant retirements – from no retirements, to retirements by plants with 25 percent capacity factor or less, to retirements by plants with a capacity factor of 35 percent or less. The use of the capacity factor thresholds are used as proxies to estimate those plants that would not be economic to retrofit or could not obtain land or permits, and would have to retire. Using a range of assumptions, DOE estimated the capacity of the plants that would retire as 38,000 to 75,000 MW. The facilities that would retire are overwhelmingly (more than 90 percent) oil- and gas-fired steam units. DOE notes that using the 25 and 35 percent or less utilization rates as proxies for the units that would retire as a consequence of this rule has the effect of assuming few coal plants and no nuclear plants would retire.

Note that this proxy approach does not account for facility-specific economic factors, including revenue streams other than from electricity sales alone, loss of generation revenues, a plant's cumulative capital and operational costs of complying with new SO_x, NO_x, mercury, or carbon emission limits, or the cost of seeking amendments to existing licenses or permits. Although, these proxies likely underestimate the potential impact of the mandate on many baseload coal and nuclear units, they are used in this analysis to provide rough approximations of possible retirement scenarios from a cooling tower mandate.

In its white paper, NERC concludes that once the deadline for the cooling tower retrofits has passed, the generation losses resulting from the requirement would reduce generation capacity by 49,000 MW, or 4.3 percent points compared to what otherwise would be in service. This loss of generation capacity would exacerbate what NERC already projects as a decline in electric generation reserve margins that are needed to ensure reliable delivery of electricity. Generally, the goal for NERC regions is to have the equivalent of between 10 and 15 percent of their peak demand available to meet contingencies. In its reference case (without a cooling tower mandate), NERC assuming no plant retirements and that all "planned" generation is built, NERC projects overall capacity reserve margins to fall to 14.7 percent by 2015. However, upon analyzing the impact of a cooling tower mandate, NERC projects that, "U.S. resource margins drop from 14.7 percent to 10.4 percent when both the retired units and auxiliary loads due to retrofitting were compared to the *Reference Case*." (NERC White Paper, p. 4). The U.S. does not have a national electricity grid, but rather a series of large regional power grids. The amount of reduced generation capacity and its impact on regional reliability would vary from region to region.

Based on the best available data, this loss of generation capacity in combination with the early retirement of facilities that either cannot or choose not to retrofit may jeopardize the ability of California, New York, and New England to maintain reserve margins needed to meet contingencies during peak electricity demand periods. (Figure 4-1, p. 32, and *see* NERC White Paper, p. 6.)

To the extent that a cooling tower mandate would cause the retirement of once-through cooling generation facilities near load centers, additional grid reliability concerns arise with the loss of local generation to provide peaking power as well as frequency and voltage support to maintain the quality of the delivered electricity. Moreover, loss of local generation would necessitate at least some increase in imported generation.

Demand-side management initiatives and smart grid technologies will help reduce future demand and replace some of the lost generation. New wind generation will continue to make increasing contributions, although this will require additional transmission. Nevertheless, additional conventional generation, almost certainly natural gas units, would be required in the near term. Although there is evidence that domestic natural gas production is increasing, these increases are not likely to keep up with growing natural gas demand, thereby increasing dependence on LNG imports that are vulnerable to potentially high global process. Replacing prematurely retired local facilities with natural gas, wind, and solar will require careful planning to ensure enough new natural gas pipeline and electric transmission facilities are sited and constructed in a timely manner.

While a detailed analysis of the impacts on electric transmission reliability was not performed, NERC advises that transmission congestion in the Mid-Atlantic Area

National Interest Electric Transmission Corridor could be expected to be aggravated by reduced capacity margins (NERC White Paper, p. 7.)

This analysis did not update previous DOE studies concerning the potential cost of construction of cooling towers. These costs are expected to be substantial,[6] and would be in addition to the cost of increasing generation and transmission to meet growing electricity demand and the changing mix of the generation fleet to include more remotely-located clean energy sources.

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[6] During the rule-making, DOE submitted analyses to the Environmental Protection Agency (EPA) concluding that the retrofit to closed-looped cooling systems would impose significant capitol cost burdens. The EPA, in adopting the rule, found retrofit of existing plants was many times higher, $130 to $200 million per tower, than for new facilities that are required to install cooling towers.

Introduction: Request from Congress

The U.S. Senate Committee on Appropriations Subcommittee on Energy and Water Development requested the Office of Electricity Delivery and Energy Reliability of the Department of Energy (DOE or Department) to prepare an analysis of the impacts on electricity reliability on a regional basis if the Environmental Protection Agency (EPA) were to promulgate a Clean Water Act (CWA) thermal discharge rule that would require all existing steam generators to retrofit to use cooling towers rather than other options to condense and cool the steam after its use in the generation of electricity. Specifically, the Subcommittee sent the following questions for the record to DOE after the FY 2009 appropriations hearing held on March 5, 2008.

> 1. Part of DOE's mission is to promote America's energy security through reliable, clean and affordable energy. I understand that EPA plans to propose a revised rule before the end of the year governing cooling water intake structures at existing power plants as a result of a recent 2nd Circuit court decision. The central question before the agency is what should be deemed the best technology available (BTA) to minimize the adverse environmental impacts that might result from cooling water intake structures. The Court has directed the agency to clarify why cooling towers or their performance equivalent, were not deemed BTA. I understand that approximately 40 percent of the nation's existing generation will be directly and materially affected by this rulemaking. Has DOE examined the short and long term energy reliability and security impacts of designating cooling towers as BTA for existing generation facilities and does DOE believe they would be significant?
>
> 2. Could DOE do an analysis of the potential impacts for this Committee, including the impacts on electricity reliability on a regional basis, and provide preliminary results as early as May so that these results could be meaningfully considered in the EPA rulemaking?

In response to this request, the Department determined that this analysis should focus on the electricity reliability impacts that would be created if a mandatory cooling tower rule were issued by the EPA. The Department did not attempt to quantify the costs to industry, consumers, and the economy of such a mandate. As discussed later in the analysis, during EPA's rulemaking DOE submitted analyses demonstrating a significant cost associated with requiring a retrofit of existing steam generators.

Chapter 1: Background of Thermoelectric Power Plant Cooling Systems – Technical and Regulatory Issues

Substantial progress is expected in electric power demand reduction technologies and programs. Nevertheless, the DOE Energy Information Administration (EIA) projects electricity demand will grow at an average of 1.1 percent per year through 2030. Substantial amounts of new generation capacity are planned or anticipated for construction over the next decade to meet this demand growth or replace generation facilities scheduled for retirement. Whether sufficient new generation and transmission will be operational to keep pace with demand will depend on public acceptance, availability of labor and materials, new regulatory programs, tax policy, and other factors. Clearly, meeting the growing demand for reliable electricity will require continued reliance on the large base of currently operational power plants for the foreseeable future.

According to EIA, approximately 70 percent of the Nation's annual electricity generation in 2006 was produced by thermoelectric generating plants.[7] More than 2,775 billion kilowatt-hours (kWh) were generated by these largely baseload coal and nuclear plants, although older oil- and natural gas-fired steam plants were often used during periods of peak electricity demand.

Thermoelectric power plants generate electricity by boiling water to produce steam. Regardless of the primary fuel (e.g., coal, oil, natural gas, biomass, or nuclear), the process is fundamentally the same. Water is boiled at very high temperature and pressure, and the resulting superheated steam is harnessed to spin a turbine coupled to a generator. While much of the energy is extracted from the steam and used to generate electricity, the turbine exhaust steam must be cooled and condensed so that the water can be reheated and sent back to the turbine to produce more electricity. This process, known as the Rankine Cycle, has been used to generate electricity for more than a century.

In order to cool and condense the turbine exhaust, a large heat "sink" is required. The simplest and most effective power plant heat sink involves the use of substantial volumes of cooling water. Historically, power plants were located on large water bodies or high flow-rate rivers typical of the northeastern United States. Many of these facilities were constructed using what is known as once-through cooling systems, which draw large volumes of cool water from the source (such as a river or ocean), pass it through the power plant's condenser, and return it, warmed by the heat transfer process, to the source downstream from the intake.

Accordingly, section 316 of the Federal Water Pollution Control Act (Clean Water Act), was enacted to provide for the regulation of thermal discharges to the Nation's surface waters. Regarding the existing fleet of electric power plants, section 316 includes three subsections, two of which separately address thermal discharges and cooling water intake structures. Section 316(a) addresses thermal discharges from power plants and provides

[7] DOE/EIA, *Annual Energy Outlook 2008* (June, 2008). http://www.eia.doe.gov/oiaf/aeo/index.html.

that *"the Administrator [of the Environmental Protection Agency (EPA)]…may impose an effluent limitation with respect to the thermal component of the discharge…that will assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife"* in and on the receiving body of water. Section 316(b) addresses the location, design, construction, and capacity of cooling water intake structures and requires that the structures *"reflect the best technology available for minimizing adverse environmental impact."* This latter provision addresses impingement and entrainment[8] of biota with resulting mortality of fish, larvae, and other aquatic organisms.

Section 316 was added as a series of amendments to the Clean Water Act in 1972. Applicability of requirements under section 316(a) was divided to address affected facilities existing as of July 1, 1972, and those built after July 1, 1972. Generation companies comply with section 316(a) mostly by designing plants to produce a specific discharge that minimizes environmental impacts. The rise in temperature of the water discharged to the receiving water body must be kept at a level such that thermal discharges do not adversely affect wildlife in and on that water body, commonly accomplished by dilution. In order to minimize the temperature increase of the cooling water, many large plants require significant water withdrawals, often in excess of 100 million gallons per day.

EPA promulgated a final regulation implementing 316(b) in 1976. Subsequent to substantial challenges from industry groups, the regulation was remanded in 1977, and not addressed again until the 1990s.[9] Even lacking Federal regulation, however, most newer plants have been designed and constructed with cooling systems that require much lower water withdrawals than once-through cooling systems (e.g., cooling towers or recirculating cooling systems, including man-made cooling reservoirs or cooling ponds). Nonetheless, DOE estimates that today, over half of the existing thermoelectric power plants (fossil and nuclear combined) – nearly 300 gigawatts (GW) – are still equipped with once-through cooling systems.

After nearly two decades and a 1995 consent decree, EPA committed to complete a 316(b) rule by August 2001. EPA entered into a series of rulemaking actions, breaking the 316(b) effort into three phases: Phase I established standards for cooling water intake structures at new facilities. The final rule was published November 9, 2001, and was later amended with minor changes on June 19, 2003.[10, 11] Phase II established standards for existing power plants. The final rule was published February 16, 2004.[12] Phase III

[8] Impingement refers to aquatic organisms pinned against parts of the intake structure, entrainment refers to the sucking in and carrying along of organisms throughout the cooling system. Impingement and/or entrainment result in physical harm to the affected organism.
[9] EPA, *Phase I – New Facilities, Proposed Rule for the Location, Design Construction and Capacity Standards for Cooling Water Intake Structures at New Facilities.* EPA-821-F-00-008 (July, 2000).
[10] EPA, *Phase I – New Facilities, Final Rule, Phase I, Fact Sheet.* EPA-821-F-01-017 (November, 2001).
[11] EPA, *Phase 1 – New Facilities, Amended Final Phase I Rule, Fact Sheet*. EPA 821-F-03-010 (June, 2003).
[12] EPA, *Phase II- Large Existing Electric Generating Plants, Fact Sheet: Final Regulations*. EPA-821-F-04-003 (February, 2004).

established categorical requirements (not standards) for new offshore oil and gas extraction facilities.

Relevant to a substantial portion of the existing fleet, final Phase II regulations published in 2004 required that existing power plants withdrawing 50 million gallons per day or more and using at least 25 percent of the water withdrawn for cooling purposes, must comply with requirements to minimize impingement and entrainment. The final rule provided several compliance alternatives including technological and restorative measures but did not require installation of recirculating cooling systems (e.g., cooling towers) at facilities equipped with once-through cooling systems.[13]

On January 25, 2007, the Second U.S. Circuit Court of Appeals remanded several provisions of the Phase II Final Rule (see, Riverkeeper, Inc., v. EPA, 475 F.3d 83, (2nd Cir. 2007)). In response, on March 20, 2007, EPA suspended the Phase II Final Rule.[14] An appeal of the Second Circuit decision was filed by Entergy Corporation and others, and the U.S. Supreme Court has agreed to hear the case. The United States filed a brief in support of the EPA being able to compare costs with benefits in determining the best technology available for minimizing adverse environmental impacts at cooling water intake structures.

DOE estimates that 385 existing power plants (~ 300 GW) could be affected by Phase II regulations. Potential impacts of imposing stringent 316(b) regulations on existing power plants could result in decreased power output due to auxiliary power requirements (parasitic load) associated with cooling water. In addition, the circulating water in a closed-cycle system is usually warmer than the fresh water in a once-through cooling system. The use of warmer water results in less efficient operations, resulting in "derating" the maximum efficiency of the unit. The combination of the auxiliary power load and derating that would result from a retrofit of a once-through cooling to a closed-cycle system is often referred to as the "energy penalty."

DOE conducted an assessment of the energy penalty associated with retrofitting coal-based power plants equipped with once-through cooling systems with either recirculating evaporative cooling towers or indirect dry cooling technology (NETL Energy Penalty Analysis).[15] (Evaporative [wet] cooling towers can be either natural draft or mechanical draft; the two are significantly different in numerous critical respects, including land use.) The NETL analysis considered a variety of cooling system design assumptions and ambient conditions for both wet-and dry-cooling tower retrofits.[16]

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[13] EPA, *Phase II- Large Existing Electric Generating Plants, Fact Sheet: Final Regulations*. EPA-821-F-04-003 (February, 2004).

[14] EPA, *Phase II Implementation Memo*. Last accessed (August 2008) online at http://www.epa.gov/waterscience/316b/phase2/implementation-200703.pdf.

[15] NETL, *Energy Penalty Analysis of Possible Cooling Water Intake Structure Requirements on Existing Coal-Fired Power Plants* (October, 2002). http://www.netl.doe.gov/technologies/coalpower/ewr/water/pdfs/EP%20Final%20Report.pdf

[16] Wet cooling exchanges heat primarily by evaporation, with concomitant consumptive water loss. Wet cooling towers can be either natural draft (i.e., ambient air flow is maintained by convective buoyancy effects) or mechanical draft (i.e., air flow is maintained by fans). The two technologies are significantly

Energy penalties were estimated for five representative regions of the continental United States,[17] and calculated both for an average annual energy penalty and an energy penalty based on the one-percent-high temperature (the recorded ambient condition that is exceeded only 1 percent of the time June through September at each modeled location). The one-percent-high temperature represents the time of year when the performance of the retrofit system is expected to be poorest and the electricity demand is likely to be highest. As expected, the energy penalty that results from retrofitting from once-through cooling to dry cooling towers is higher than that which results from retrofitting from once-through to wet cooling towers. Also, the energy penalty observed during the one-percent-high temperature is more severe than that which is observed as an average annual energy penalty. Summary results of the NETL analysis are presented in Table 1-1.

Table 1-1: Comparative Energy Penalties for a Once-Through Cooling System Retrofit[a]
Wet Cooling Tower Retrofit

Region	Average Annual Energy Penalty, Percent	One-percent-highest Energy Penalty, Percent
Delaware River Basin	1.18	3.12
Michigan/Great Lakes	1.47	3.08
Ohio River Valley	1.14	2.98
South	0.82	2.41
Southwest	0.80	2.06

Notes: a) The energy penalties presented here are for representative fossil (coal) model plants. Nuclear plants were not part of the above analysis and were not modeled. However, the literature suggests that nuclear plants would have slightly higher energy penalties for similar retrofits.

In addition to assessing the energy penalty associated with retrofitting once-through systems with recirculating (closed-cycle) systems, NETL also examined facility-specific factors that may impact the feasibility of retrofitting such systems at existing plants. Recirculating cooling systems are relatively large structures and require large areas for installation. NETL commissioned the Parsons Corporation to evaluate four existing thermoelectric power plants using only publically available data. This analysis affirmed the results of the earlier NETL Energy Penalty Analysis and concluded that the retrofit of closed-loop cooling systems would impose significant capital cost burdens.[18]

different in a number of critical respects. The DOE analysis focused on the application of mechanical draft wet cooling systems. Dry cooling, which is akin to an automobile radiator, does not sustain water loss, but is less energy-efficient, causing higher parasitic energy losses from operation. In either case, a certain amount of water is periodically returned to the source in the form of "blowdown" as a means of purging the system of built up impurities.

[17] The regions and representative locations considered in the DOE Energy Penalty Analysis included the Delaware River Basin (Philadelphia, PA), Michigan/Great Lakes (Detroit, MI), Ohio River Valley (Indianapolis, IN), South (Atlanta, GA), and Southwest (Yuma, AZ).

[18] Parsons Corporation, *An Investigation of Site-Specific Factors for Retrofitting Recirculating Cooling Towers at Existing Plants* (October 8, 2002). http://www.netl.doe.gov/technologies/coalpower/ewr/water/pdfs/316b_NETL_ParsonFinalReport_wAddnd_012203.pdf

Following the issuance of the Parsons Corporation analysis, NETL held discussions with each of the utilities that owned the plants examined in the analysis. In addition to the cost and energy impacts, additional factors not addressed in the Parsons Corporation were identified as worth considering. A condition peculiar to mechanical draft cooling towers is that, under certain atmospheric conditions, a visible plume forms above the cooling tower. This plume can have deleterious effects (i.e., fogging, icing, corrosion) to nearby infrastructure. In the case of natural draft (hyperbolic) cooling towers at fossil-fired power plants, there is the potential for sulfuric acid mist formation from comingling of the water vapor and smokestack plumes of SO_2.

NETL concluded that the supplemental information received from discussions with the plant owners only reinforced the conclusions of the two earlier studies and indicated that cooling tower retrofits can be substantially more difficult and costly when significant, facility-specific constraints are considered.[19] As part of the rule making process, the Energy Penalty Analysis, the Parsons Corporation analysis, and the DOE addendum to the Parsons Corporation analysis based on the conversations with the plant owners were formally submitted to EPA during their regulatory effort.[20]

[19] NETL, Addendum to Report *An Investigation of Site-Specific Factors for Retrofitting Recirculating Cooling Towers at Existing Power Plants* (January 22, 2003). http://www.netl.doe.gov/technologies/coalpower/ewr/water/pdfs/316b_NETL_ParsonFinalReport_wAddnd_012203.pdf

[20] EPA, *Response to Public Comment: CWA Section 316(b) Phase II Existing Facility Rule—Final* (March 29, 2004). http://www.epa.gov/waterscience/316b/phase2/comments/author-ph2.pdf.

Chapter 2: Maintaining Electricity Adequacy

As discussed in Chapter 1, this analysis assumes that a new rule is issued by the EPA pursuant to section 316 of the Clean Water Act that will require all steam-powered electricity generating facilities to use cooling towers to condense the steam that passes through its generators. This analysis indicates that under such a scenario, roughly half of the coal and nuclear facilities in the United States may be required to retrofit and install cooling towers. To provide a context within which to asses the implications of this requirement, the following chapter will examine the current U.S. generating fleet and explore the potential challenges of meeting electricity demand through 2020.

To promote a more efficient use of electricity and slow demand growth, DOE has strongly supported energy efficiency, demand response initiatives, and implementation of smart grid technologies. While the annual growth rate of electricity demand has gradually declined during the past 40 years, it nevertheless continues to grow. The EIA reported in its most recent long-term energy forecast that electricity demand will maintain a 1.1 percent increase every year through 2030, leading to an increase in electricity consumption of 30 percent between 2006 and 2030.[21] Given this outlook, construction of additional generating capacity will be necessary, not only to meet additional demand with an adequate reserve margin, but also to replace existing generation facilities that will be retired.

Electricity operators must plan to provide adequate generation capacity during periods of peak electricity demand, with a margin of additional capacity ready for contingencies, such as an unexpected generation plant shutdown. These capacity requirements are expected to grow despite increasing participation of consumers and utilities in demand response programs and investments in energy efficiency. According to data collected by NERC, average peak demand during the summer is expected to increase by over 135,000 MW or 17.7 percent by 2017 while committed resources[22] are projected to grow by only 77,000 MW.[23] Even assuming no plant retirements, certain regions may be unable to supply enough committed resources to meet the projected increases in peak demand.

Meeting the need for this additional generation capacity will be challenging. Expectations for completion of new generation facilities must be informed by an understanding of the additional time needed for permitting and construction. Because the average cost to build a single power plant (all generating types considered) has been significantly increasing over the past several years, many utilities have become very

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[21] DOE/EIA, *Annual Energy Outlook 2008,* p. 10 (June, 2008).

[22] Committed resources include generating capacity resources that exist, are planned, or under construction. These resources are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

[23] NERC *2007 Long-Term Reliability Assessment*, p. 11, (October, 2007). (NERC further states that, "a major driver of the uncertain or inadequate capacity margins is the industry's relatively recent shorter-term approach to resource planning and acquisition, relying heavily on unspecified, undeveloped, and/or uncommitted resources to meet projected demand.")

cautious in planning future construction.[24] It is important to also consider the sometimes even longer lead times are required to address electricity delivery concerns such as the need to expand transmission capacity, strengthen grid management, and improve distribution systems as needed in order to satisfy the expectations of future demand growth. This particularly applies to situations where longer distances will separate generating facilities and consumers.

Existing Generation Fleet

The United States uses a broad energy mix to generate electricity. This mix shifts over time, most recently emphasizing natural gas and renewable energy, which is expected to continue in the mid-term. However, coal has long been the predominant fuel for electricity generation and continues to generate almost half of the Nation's energy (*see* Figure 2-1).

Coal-Fired Generation

Coal has long been a reliable and relatively inexpensive energy source, providing a majority of America's base-load generation. Most of the coal facilities operating in the United States today were built before 1990. EIA projects that coal will continue to be the dominant source of electricity generation in the mid-term, increasing its generation by 357 billion kWh between 2006 and 2020 (*see* Figure 2-2).[25]

Figure 2-1. U.S. Net Generation by Energy Source, 2007

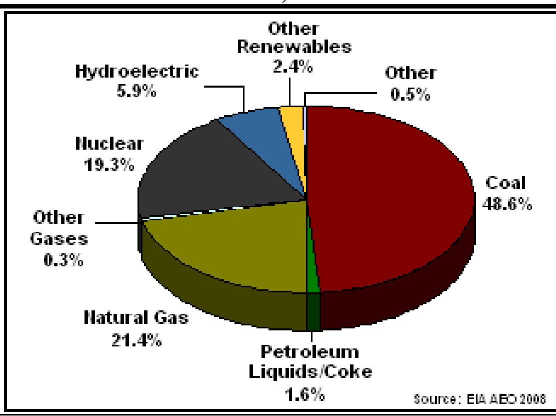
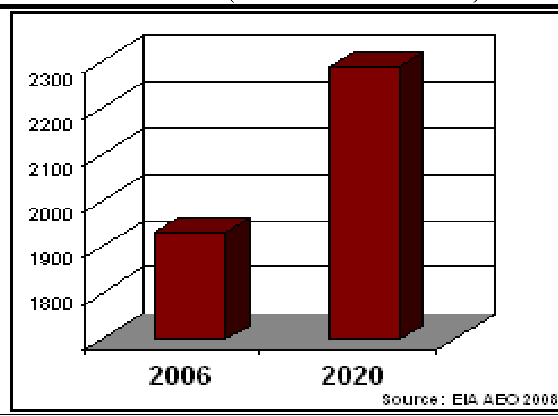


Figure 2-2. Projected Electricity Generation from Coal (billion kilowatthours)



However, coal generation in the United States has faced increased scrutiny because these plants produce roughly twice as much carbon dioxide as natural gas-fired power plants for each unit of electricity delivered.[26] This is a substantial amount, considering electricity generation emitted 33.7 percent of all U.S. greenhouse gasses in 2006.[27] Consequently, coal-fired power plant developers are faced with increasing scrutiny along with regulatory uncertainties, higher capital costs, and skilled labor shortages. These

[24] *See, e.g.,* Wall Street Journal, *Costs to Build Power Plants Pressure Rates* (May 27, 2008).
[25] DOE/EIA *Annual Energy Outlook 2008*, p. 131 (June, 2008).
[26] The Environmental Protection Agency (EPA) *Regulating Greenhouse Gas Emissions under the Clean Air Act*, p. 37 (July, 2008).
[27] Id. p. 101.

problems caused delays in the construction along with several cancelled plans for new coal plants. The current coal-fired projects in development reflect a potential surge in new facility additions. However, it has been evident in the past that coal plant announcements exceed actual plant completions. A NETL analysis indicates that by 2007, only about 12 percent of the capacity announcements pending in 2002 were completed during the subsequent five years.[28]

Nuclear Power

Nuclear power has been a vital source of base-load electricity generation in the United States since the early 1960s. Currently, a fleet of 104 operating nuclear power plants supply about one-fifth of the Nation's total generation.[29] Substantial efforts have been made to increase the output of these units. In 2007, these plants were able to operate at an estimated capacity factor (the percentage of time a facility is operating) of 91.5 percent compared to 71.1 percent a decade earlier,[30] increasing net generation by 28.3 percent.[31] Unlike fossil-fuel fired units, nuclear plants generate electricity with virtually no CO_2 emissions or criteria air pollutant emissions. However, new construction for a reactor has not started since the late 1970s; the last plant to begin commercial operation was the Watts Bar I site in 1996 by the Tennessee Valley Authority (and construction for this plant began over 20 years earlier in 1976).[32]

Looking forward, the EIA projects 10.7 GW of additional nuclear generation capacity between 2006 and 2020 (including 2.7 GW of uprates).[33] NERC's 2007 Long-Term Reliability Assessment assumes 12 GW of proposed nuclear capacity to come online by 2016.[34] The EIA reports that nine applications for new commercial nuclear reactors have been submitted and as many as three reactors could come online between 2114 and 2016.[35] However, delays could be caused by a recent jump in construction costs for nuclear facility developers. Recent estimates anticipate a single nuclear plant could be priced anywhere between $5 and $12 billion, particularly due to the skyrocketing costs for cement, copper, and steel, as well as shortages of skilled labor and specialized parts – particularly the critical pressure vessels.[36]

Natural Gas-Fired Generation

Natural gas-fired generating facilities have several advantages over coal-fired plants, including lower air pollution and CO_2 emissions, lower capital costs, shorter construction times, and smaller site footprints.[37] Unlike base-load coal and nuclear facilities, natural gas plants can be designed to respond quickly to changing electricity demand or

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[28] DOE/NETL, *Tracking New Coal-Fired Power Plants, pp. 9, 14* (February, 2008) – updated with Revised EIA AEO 2008 Projections).
[29] DOE/EIA *Annual Energy Review 2007*, p. 271 (June, 2008).
[30] Id. p. 273.
[31] Id. p. 226.
[32] Id. p. 271.
[33] DOE/EIA, *Annual Energy Outlook 2008*, p. 19 (June 2008).
[34] NERC, *NERC 2007 Long-Term Reliability Assessment*, p. 14 (2007).
[35] *DOE/EIA Status of Potential Nuclear Reactors in the United States*, http://www.eia.doe.gov/cneaf/nuclear/page/nuc_reactors/reactorscom.html.
[36] The *Wall Street Journal, New Wave of Nuclear Plants Face High Costs* (May 11, 2008).
[37] NERC, *2007 Long-Term Reliability Assessment*, p. 15 (October, 2007).

balancing intermittent generation from wind and solar. Newer combined-cycle facilities are able to utilize natural gas more efficiently and provide base-load generation. These attractive features have resulted in an 86.3 percent increase in natural gas-fired electricity generation between 1997 and 2007.[38] Today, roughly one-fifth of America's electricity generation is provided by natural-gas fired power plants.[39] A majority of this generation is used to meet peak electricity demands, especially during the summer when natural gas net capacity exceeds other forms of generation. For example, natural gas accounted for 39.5 percent of the total electric net summer capacity in 2007, compared to smaller contributions by coal (31.4) and nuclear (10.1).[40] Moreover, natural gas units are now producing more electricity in non-peak hours compared to earlier years.

During 2007, 6.9 trillion cubic feet (Tcf) of natural gas (over one-third of total U.S. consumption) was used for electricity generation.[41] To satisfy this demand, the United States has relied primarily on domestic production, importing only about one-fifth of its total consumption, primarily through natural gas pipelines from Canada.[42] These Canadian imports experienced positive growth to satisfy a growing demand between 1988 and 2005, when U.S. natural gas production (gross withdrawals) remained relatively static.[43] During this 17-year period, Canadian imports more than doubled from 1.27 Tcf to 3.7 Tcf.[44] Looking forward, however, EIA projects a sharp decline in natural gas imports from Canada through 2020 (*see* Figure 2-3).[45]

Domestic natural gas production has responded to higher prices by ramping up production, with expected increases of 7.8 percent in 2008 and 3.8 percent in 2009.[46] This current surge is the result of expansion of the outer continental shelf production in the Gulf of Mexico and horizontal directional drilling techniques in natural gas-bearing shale deposits. In 2007, natural gas producers drilled over 31,252 wells, nearly doubling 2002 figures.[47] Domestic natural gas pipeline expansions also reached a record high level of new capacity in 2006 and 2007 with additions totaling 27.6 billion cubic feet (Bcf) per day.[48] By 2020, the EIA projects the completion of an Alaskan pipeline would deliver an additional 4.5 Tcf per year to the United States.[49] Despite these expansions, EIA's long term forecast predicts domestic natural gas production will rise by only 6.3 percent between 2006 and 2020.[50] Even if the EIA long-term forecast underestimates the potential for increased domestic natural gas production, domestic supply is unlikely to match the growth in demand for natural gas over the next decade. A majority of the

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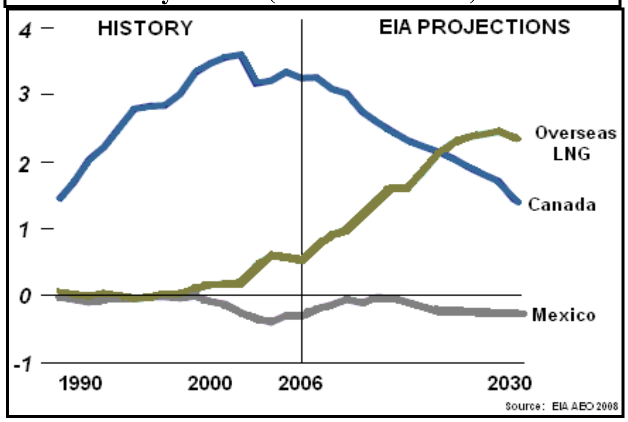
38 DOE/EIA, *Annual Energy Review 2007,* p. 226 (June, 2008).
39 DOE/EIA, *Electric Power Monthly,* p.15 (April, 2008).
40 DOE/EIA, *Annual Energy Review 2007,* p. 260 (June, 2008).
41 Id. p. 191.
42 Id. p. 183.
43 DOE/EIA, *Annual Energy Review 2007*, p. 185 (June, 2008).
44 Id. p. 187.
45 DOE/EIA, *Annual Energy Outlook 2008*, p. 78 (June, 2008).
46 DOE/EIA, *Shorterm Energy Outlook*, p. 5 (September 9, 2008).
47 DOE/EIA Natural Gas Navigator, *U.S. Natural Gas Exploratory and Developmental Wells Drilled (Count)* (http://tonto.eia.doe.gov/dnav/pet/pet_crd_wellend_s1_a.htm]).
48 NERC, *2008 Summer Reliability Assessment*, p. 16 (May, 2008).
49 DOE/EIA, *Annual Energy Outlook 2008*, p. 140 (June, 2008).
50 Id. p. 139.

required new supply will need to come in the form of LNG imports, which the EIA projects will increase from 0.5 Tcf in 2006 to 2.4 Tcf in 2020. The trend of increasing purchases of LNG imports to keep up with growing domestic natural gas demand is illustrated in Figure 2-3, below.

Figure 2-3. Net U.S. Imports of Natural Gas by Source (trillion cubic feet)



In order to support the projected need for increased LNG imports, a robust North American infrastructure will be crucial. The Federal Energy Regulatory Commission (FERC) reports that six regasification terminals currently import LNG into the continental United States. According to the EIA, total U.S. LNG-importing capacity will grow from 1.5 Tcf in 2006 to 5.2 Tcf in 2009 with the completion of two new receiving terminals and several facility expansions.[51] Although these projections indicate U.S. infrastructure will remain capable of importing a steadily increasing supply of LNG, NERC suggests that actual imports "will depend on relative global prices."[52]

EIA anticipates a significant increase in global LNG liquefaction capacity in 2009. However, continuing natural gas demand growth and higher relative prices in Europe and Asia are expected to attract much of the new supply. In its August Short-Term Energy Outlook, EIA notes that the futures price of natural gas for January 2009 delivery in the United Kingdom (as reported on the Intercontinental Exchange) is about double the futures price for natural gas in January 2009 on the New York Mercantile Exchange (NYMX). Accordingly, EIA has been adjusting its near-term forecast for LNG imports to the United States. In its August Short-Term Forecast, EIS indicates it expects U.S. LNG imports fall from 2007's 771 Bcf to only 390 billion cubic feet (Bcf) in 2008 and 480 Bcf in 2009.

The EIA's longer-term projections indicate natural gas will continue contributing approximately 20 percent of the total U.S. electricity generation through 2017. However, certain legislation leading to a substantial increase of natural gas use for electricity generation could have detrimental effects on electricity reliability as well as the economy. Consider a recent EIA-conducted analysis of the proposed Lieberman-Warner Climate

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[51] DOE/EIA, *Annual Energy Outlook 2008*, p. 78 (June 2008).
[52] Id. p. 16.

Security Act (S. 2191) which stated that the affects of the bill would require nearly twice as much natural gas generation by 2030 without a widespread availability of carbon capture and storage (CCS) technology.[53] Doubling the U.S. natural gas-fired generation would require additional LNG imports. However, the EIA stresses the "uncertainty in future domestic and overseas natural gas prices."[54] A separate recent report by EPA warns that: "Among other effects, a large policy-forced shift towards increased reliance on imported LNG would raise energy security and economic concerns by raising domestic prices for consumers (including electricity prices) and increasing U.S. reliance on foreign sources of energy."[55] Without EIA's-projected increases in net coal and nuclear generation, an additional 2.1 Tcf per year would be needed to provide sufficient natural gas-fired generation in 2020.[56] Accordingly, the premature closures of existing coal or nuclear generation facilities, whether the result of a cooling tower mandate or of any other regulatory measure, could require substantial additional generating units dependent on LNG imports that are vulnerable to potentially higher global prices.

Renewable Generation

DOE strongly supports research, development, demonstration, and commercial penetration of renewable energy for electricity generation. While hydroelectric generation has long been the largest source of renewable generation, future growth is limited due to a lack of appropriate sites (*see* Figure 2-4).[57] Alternatively, non-hydro renewables is seeing significant growth due to 25 States and the District of Columbia having "renewable portfolio standards" (RPS) that mandate future minimum levels of electric generation from renewables. RPS initiatives generally require that a specific percentage of a utility's electricity be generated with non-hydroelectric renewable sources by a certain date in the future. If fully met, these existing mandates will require about 61 GW of new renewables by 2025, or about 15 percent of projected electricity demand growth.[58] While biomass, geothermal, small hydro and now some beginnings of solar usage have been built due to the State mandates, wind has captured 93 percent of the RPS capacity additions. Wind power's contribution has risen significantly throughout the past decade providing 10 times more generation compared to a decade ago. EIA's monthly analysis reported wind generation's year-to-date generation April 2008 was 38

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[53] DOE/EIA, *Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, p 25.

[54] DOE/EIA, *Annual Energy Outlook, 2008* (June, 2008) p. 79. According to the EIA, "given the uncertainty in future domestic and overseas natural gas prices, the level of future U.S. LNG imports is highly uncertain. In the high price case, the higher world crude oil price is expected to result in increased natural gas consumption in overseas energy markets, exerting upward pressure on LNG prices. In addition, some LNG contract prices are tied directly to crude oil prices. Higher crude oil prices will also [place] additional pressure on world natural gas supplies. Collectively, these activities are expected to increase overseas wellhead natural gas prices and worldwide LNG prices, reducing both domestic natural gas consumption and LNG imports in the United States."

[55] EPA, *Regulating Greenhouse Gas Emissions under the Clean Air Act*, p. 39.

[56] Assumes nuclear and coal remain at 2008 capacity levels, less planned retirements, and operate at capacity factors consistent with Annual Energy Outlook 2008 values. Generation from missing coal and nuclear is assumed to be made up by natural gas combined cycle with 50 percent capacity factor.

[57] DOE/EIA, *Annual Energy Outlook 2008*, p. 71 (June, 2008).

[58] Lawrence Berkeley National Lab, *Renewable Portfolio Standards in the U.S.: A Status Report*, p. 1 (April 2008).

percent higher than April 2007, and 70 percent higher than April 2006. Wind power accounted for only 0.77percent of total U.S. generation in 2007, though it is expected to account for more in the future.[59]

Figure 2-4. Renewable Electricity Generation (billion kilowatthours)

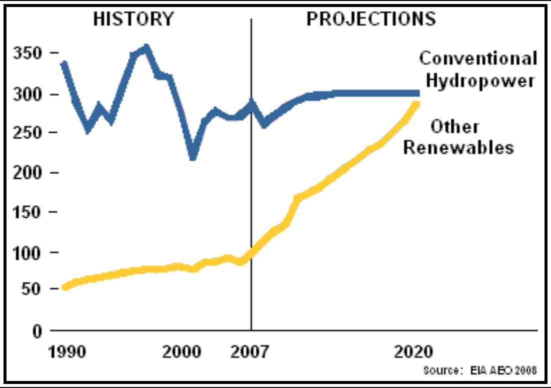
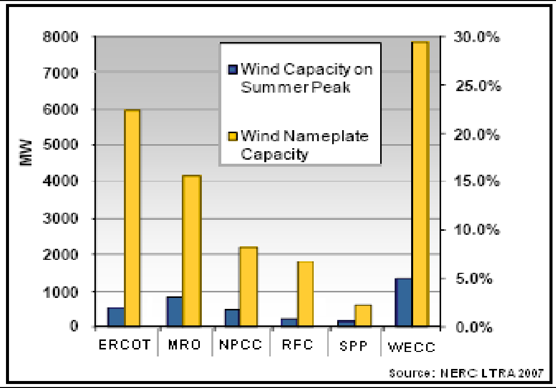


Figure 2-5. Wind Plant Nameplate and 2008 Summer Peak Capacity



DOE recently released a report which explores the impacts of strengthening wind's contribution so that it can provide 20 percent of America's electricity by 2030. In order to meet this scenario, wind capacity would need to grow from its 2006 level of about 11.5 GW to about 305 GW by 2030.[60] NERC expects a large expansion of wind power as a result of recently implemented RPS and other similar forms of legislation in over 25 States.[61]

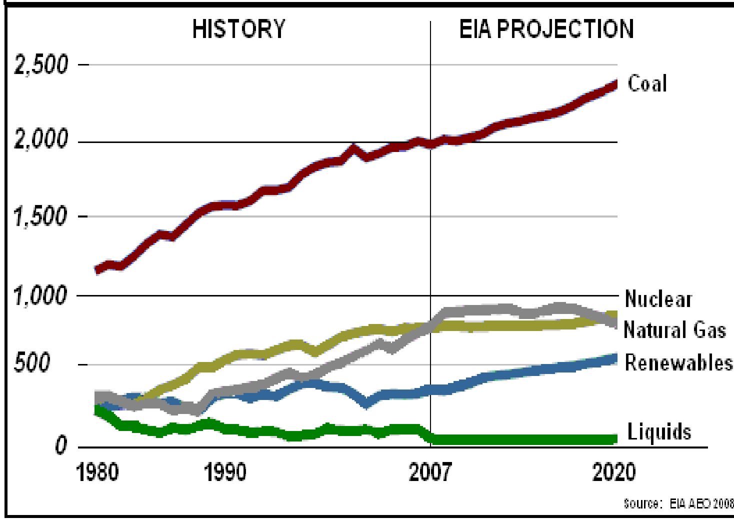
Wind generation is intermittent, which poses operational challenges for grid operators when the installed wind percentage is high. However, diversification of wind facilities over large geographic areas in the same grid will do much to balance the intermittency of particular wind farms. Nevertheless, a persistent concern is the need for improved or new transmission to bring remote wind power to consumers. Until advanced storage technology is developed along with new grid balancing mechanisms, wind farms will have an only limited ability to provide firm power without other forms of generation to ensure a steady flow of power to the grid. This is especially crucial on hot summer days, when higher temperatures thwart ideal wind conditions.

Electricity Generation Challenges

The U.S. electricity industry faces major challenges during the next 15 years to keep adequate reserve capacity margins of electricity generation available to meet peak demand growth, even if that peak demand growth is dampened by initiatives focused on demand-response, improved technology, and energy efficiency.

[59] DOE/EIA, *Electric Power Monthly*, pp. 15, 16 (April, 2008).
[60] DOE, *20% Wind Energy by 2030, p. 7 (May 2008)*
[61] NERC, *2008 Summer Reliability Assessment*, p. 17 (May, 2008).

Figure 2-6. Electricity Generation by Fuel
1980 – 2020 (billion kilowatthours)



With little additional hydroelectric or hydrokinetic generation and only modest growth in nuclear power expected by 2020, EIA projects new electricity demand will be met primarily by coal (Figure 2-6). Although there is strong DOE support for research and demonstration of CCS technologies, significant penetration of commercial-scale CCS projects is not expected until after 2020.

Should EIA's projections for net capacity additions of coal-fired plants fail to materialize, increased imports of LNG will be needed to fire natural gas generation in order to make up this shortfall. Policies that result in premature closures of existing power plants, whether the result of a cooling tower mandate, carbon limitations, or other requirements, will result in a likely boost to U.S. reliance on imported LNG during this period. If EIA's projected increases in net coal and nuclear generation do not occur, an additional 2.1 Tcf per year would be needed to provide natural gas-fired generation in 2020.[62] Accordingly, the premature closures of existing coal or nuclear generation facilities, whether the result of a cooling tower mandate or any other regulatory measure, would require additional generating units that will be dependent on imports of LNG.

Finally, a primary goal for electricity planners must include a continuation of providing reliable electricity to meet demand with an adequate reserve margin. Increasing reliance on just one or two new generation sources, such as natural gas and wind, will require careful planning to ensure that enough new pipeline and transmission facilities are completed in a timely manner.

[62] Assumes nuclear and coal remain at 2008 capacity levels, less planned retirements and operate at capacity factors consistent with Annual Energy Outlook 2008 values. Generation from missing coal and nuclear is assumed to be made up by NGCC with 50 percent capacity factor.

Chapter 3: Analysis of Wide-Scale Retrofit of Cooling Systems at Existing Electric Generating Facilities

Identification of Affected Facilities

Using information available to the public, DOE reviewed facility design and operations data to identify a subset of the existing fleet of thermoelectric power plants that are equipped with once-through cooling systems and withdraw cooling water on an annual average basis at a rate of 50 million gallons per day (MGD) or more. DOE reviewed cooling system performance information from EIA Form 767, Steam-Electric Plant Operation and Design Report, for fossil-fueled and nuclear powered thermoelectric generating facilities. DOE used the most current data available. For fossil-based units, data represent operations for the year 2005. For nuclear plants, data represent operations for the year 2000.[63] Furthermore, due to insufficient forecasted load data (*see* Table 3-6, below), Hawaii and Alaska are excluded from this analysis, as well as the analysis conducted by NERC.

Due to the limited scope of this analysis, DOE relied on existing information. DOE constrained its analysis to only those facilities where cooling system data were available, i.e., facilities with nameplate capacity greater than 100 MW. To understand the magnitude of impact that smaller facilities could have, DOE attempted to estimate the number of facilities below 100 MW that may meet or exceed the 50 MGD threshold and the aggregate fraction of electric generating capacity those facilities represent of the NERC region in which they are located. DOE estimates that approximately 160 additional plants (those in the 60-70 MW range or larger) with a combined generating capacity of nearly 17 GW may withdraw cooling water above the threshold. While large in number, on average these facilities represent 1-2 percent of the projected 2015 generating capacity of the respective NERC region in which they are located.[64] While DOE believes that a thorough analysis of the impact of a restrictive 316(b) rule should

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[63] While EIA Form 767 is considered to be one of the most extensive sets of design and operational data for the Nation's thermoelectric generating fleet, it is not exhaustive. Cooling system data considered for this analysis are required to be reported (EIA Form 767 – Schedule 6) only by facilities with a nameplate capacity greater than or equal to 100 MW. Furthermore, due to the reporting requirements and data format, there is no direct link between cooling system data and generator output. As a result, for facilities with multiple boiler/generator/cooling system combinations, there is some remaining uncertainty regarding total capacity served by each cooling system and therefore some uncertainty related to affected capacity. However, DOE believes there is sufficient information to correlate cooling systems to plant output and to differentiate between thermoelectric generation and combustion turbine generation. In instances where data-gaps were identified, DOE used other data sources (public and private) to verify or validate correlations where possible. EIA has discontinued or altered data collection activities over the past decade, removing nuclear facilities after data year 2000 and discontinuing data collection for Form 767 altogether for all facilities after data year 2005. For more information related to EIA's data collection and reporting activities see http://www.eia.doe.gov/cneaf/electricity/page/eia767.html.

[64] Two notable exceptions are Hawaii, where these smaller units approach one-third of the projected 2015 generating capacity, and Alaska, where nearly all of the units are less than 100 MW. Due to a lack of facility design information of suitable detail, no conclusions can be made as to potentially affected facilities.

consider these smaller plants that may be required to comply, the available data do not provide sufficient information to draw conclusions in this analysis.

DOE identified 391existing thermoelectric plants that meet the $\geq$ 50 MGD criterion. In order to account for facilities that were retired between the time of data submission to EIA (April 30 following the data year) and the present, DOE compared the identified subset of affected facilities to the present day operating fleet identified in the Ventyx Energy Velocity Database.[65] This comparison resulted in slightly reduced numbers of affected facilities. This subset of 385 affected plants was aggregated on the basis of the NERC Sub-Regions and is presented in Table 3-1. Figure 3-1 graphically illustrates the percentage of currently installed and operating electric generating facilities that are affected in each NERC region.

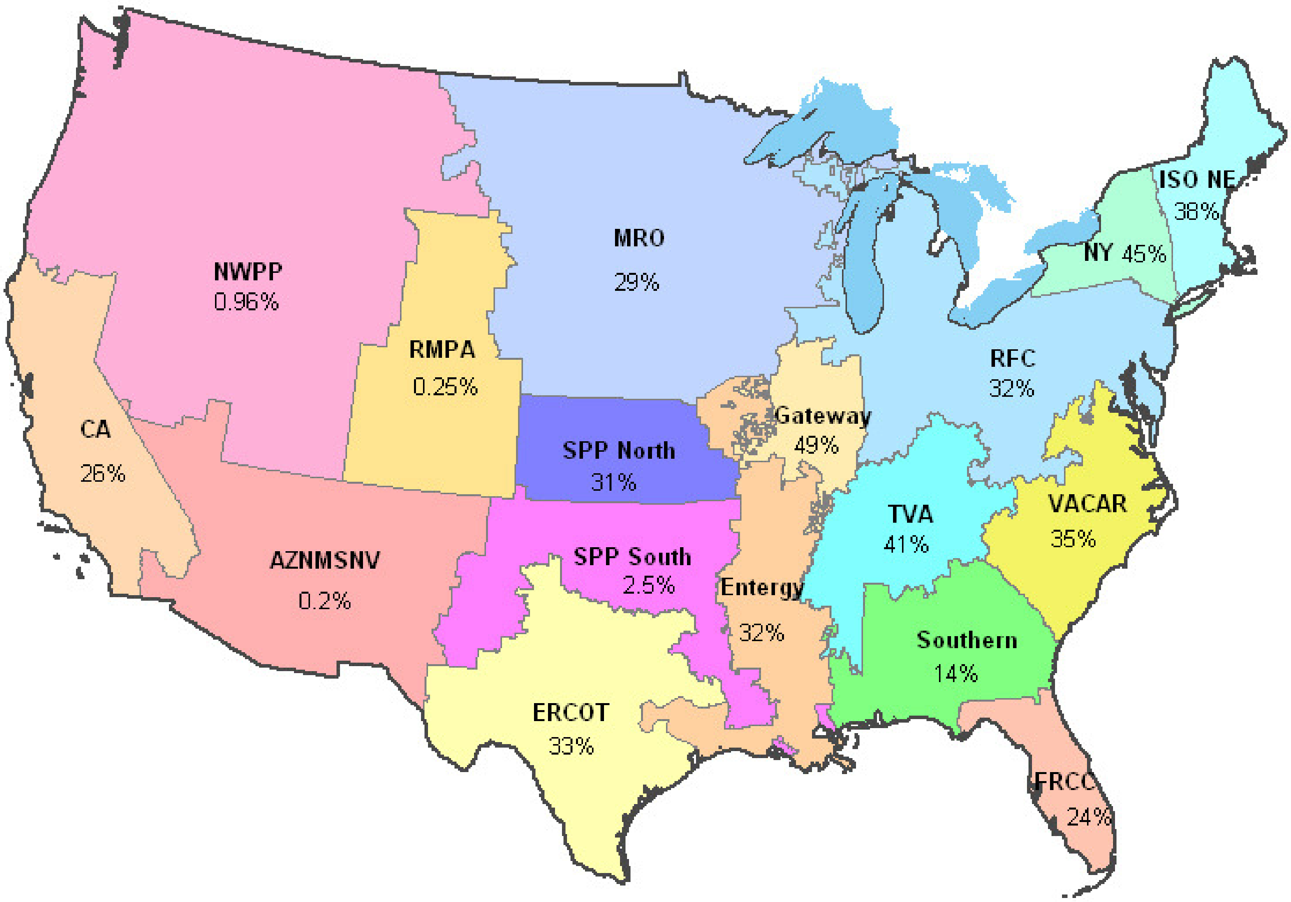
[65] http://www1.ventyx.com/velocity/vs-overview.asp

Table 3-1. AFFECTED FACILITIES
Number of Plants and Aggregate Generating Capacity with Average Daily Cooling Water Withdrawals ≥ 50 MGD

Region	Sub-Region	Fossil Steam[1]		Nuclear[2]		Total	
		Number of Plants[3]	Capacity, MW[4]	Number of Plants[3]	Capacity, MW[4]	Number of Plants[3]	Capacity, MW[4]
ERCOT	ERCOT	28	27,576	1	2,430	29	30,006
FRCC	FRCC	18	12,191	2	2,590	20	14,781
HAWAII	HI/HISR	N/A	N/A	N/A	N/A	N/A	N/A
MRO US	MRO	36	13,180	5	3,519	41	16,698
NPCC	ISO NE	20	9,170	4	4,646	24	13,817
NPCC	NY	21	15,349	5	4,343	26	19,692
RFC	RFC	98	62,220	10	15,867	108	78,087
SERC	Entergy	18	16,607	2	2,102	20	18,709
SERC	Gateway	15	12,126	1	985	16	13,111
SERC	Southern	17	10,344	0	0	17	10,344
SERC	TVA	19	17,820	2	5,973	21	23,793
SERC	VACAR	21	14,925	7	12,335	28	27,260
SPP	SPP North	10	5,138	1	1,237	11	6,375
SPP	SPP South	3	1,023	0	0	3	1,023
WECC	AZNMSNV	1	74	0	0	1	74
WECC	CA	15	13,528	2	4,555	17	18,083
WECC	NWPP	2	631	0	0	2	631
WECC	RMPA	1	40	0	0	1	40
Total		343	231,942	42	60,582	385	292,524

Notes: 1. Data based on EIA Form 767 (Steam-Electric Plant Operation And Design Report) – Year 2005 Data adjusted for retirements since 2005 using the Ventyx Energy Velocity Database.
2. Data based on EIA Form 767 – Year 2000 Data. For Year 2001 and beyond, EIA did not publish operational data for Nuclear Facilities
3. Based on EIA Plant Government ID.
4. Capacity represents the total electrical generating capacity (MW) cooled by the associated cooling system. For combined cycle systems, only the steam cycle generating capacity is captured here.

Figure 3-1. AFFECTED FACILITIES
Percent of Existing Installed Operating Capacity (Affected MW/Existing MW)



To assess the impact of retrofitting to recirculating wet cooling towers at the identified plants, DOE relied extensively on prior work conducted by NETL during EPA's earlier 316(b) activities.[66] For fossil-fueled thermoelectric plants, NETL used the estimated energy penalties for the geographic regions developed for the 2002 Energy Penalty Analysis. NETL did not estimate energy penalties for nuclear fueled facilities in the earlier 2002 report. For this analysis, DOE estimated the energy penalty for nuclear plants by adjusting the fossil energy penalties based on information obtained in the public literature.[67] Energy penalties used in this analysis for fossil- and nuclear-fueled plants are presented in Table 3-2.

Table 3-2. Energy Penalty Assumptions
Derate from Nameplate Capacity Resulting from Retrofit of Once-Through Facility to Recirculating Wet Cooling Towers

Region	Fossil[1]		Nuclear[2]	
	Annual Average Energy Penalty, % Reduction in Nameplate Capacity	1% Highest Energy Penalty, % Reduction in Nameplate Capacity	Annual Average Energy Penalty, % Reduction in Nameplate Capacity	1% Highest Energy Penalty, % Reduction in Nameplate Capacity
Delaware River Basin	1.18	3.12	1.48	3.90
Michigan/Great Lakes	1.47	3.08	1.84	3.85
Ohio River Valley	1.14	2.98	1.43	3.73
South	0.82	2.41	1.03	3.01
South West	0.80	2.06	1.00	2.58

Notes: 1. Source: NETL, *Energy Penalty Analysis of Possible Cooling Water Intake Structure Requirements on Existing Coal-Fired Power Plants*, October 2002
2. Assumes energy penalty for nuclear plants is ~25% greater than that of a fossil plant.

Using the energy penalties identified in Table 3-2, DOE applied these factors to each affected facility based on the State in which the plant is located.[68] Estimates of energy penalties for each NERC sub-region were applied for both the annual average basis as well as for the one-percent-highest temperature basis. Table 3-3 presents the total capacity derate as well as remaining thermoelectric capacity for each NERC sub-region if all affected facilities (as indicated in Table 3-1) were required to retrofit from once-through cooling systems to wet cooling towers.

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[66] For this analysis, DOE did not consider retrofitting once-through cooling to dry-cooling systems. Retrofit of a dry system would result in a greater energy penalty, reduced reliability, and higher economic cost. The impact of requiring such a retrofit would be greater (worse) than the results presented here.
[67] Veil, J.A., J.C. VanKuiken, S. Folga, and J.L. Gillette, *Impact on the Steam Electric Power Industry of Deleting Section 316(a) of the Clean Water Act: Energy and Environmental Impacts*, Argonne National Laboratory Report ANL/EAIS-5 (January 1993).
[68] Energy penalties were applied to units in each State based on a "best-fit" assumption of the climate conditions (temperature and humidity) of the representative regions considered in the DOE Energy Penalty Analysis. For States that did not fit into one of the existing representative regions, the energy penalty was averaged across two regions that were considered closest to the climate conditions of the State in question.

Table 3-3. Impact of Energy Penalty Due To Cooling Tower Retrofits At All Affected Facilities
Capacity Derate at Affected Facilities

		Annual Average Energy Penalty			Highest 1% Ambient Condition		
Region	**Sub-Region**	**Capacity Derate, MW Removed From the Grid**	**Remaining Capacity, MW**	**% Capacity Reduction**	**Capacity Derate, MW Removed From the Grid**	**Remaining Capacity, MW**	**% Capacity Reduction**
ERCOT	ERCOT	251	29,755	0.8%	738	29,268	2.5%
FRCC	FRCC	127	14,654	0.9%	372	14,409	2.5%
HAWAII	HI/HISR	N/A	N/A	N/A	N/A	N/A	N/A
MRO US	MRO	236	16,462	1.4%	519	16,179	3.1%
NPCC	ISO NE	179	13,638	1.3%	467	13,350	3.4%
NPCC	NY	238	19,454	1.2%	634	19,058	3.2%
RFC	RFC	1,235	76,852	1.6%	2,674	75,413	3.4%
SERC	Entergy	170	18,539	0.9%	487	18,222	2.6%
SERC	Gateway	154	12,957	1.2%	404	12,707	3.1%
SERC	Southern	85	10,259	0.8%	249	10,095	2.4%
SERC	TVA	217	23,576	0.9%	626	23,167	2.6%
SERC	VACAR	271	26,989	1.0%	765	26,495	2.8%
SPP	SPP North	77	6,298	1.2%	202	6,173	3.2%
SPP	SPP South	8	1,015	0.8%	24	999	2.3%
WECC	AZNMSNV	1	73	1.4%	2	72	2.7%
WECC	CA	161	17,922	0.9%	446	17,637	2.5%
WECC	NWPP	9	622	1.4%	19	612	3.0%
WECC	RMPA	0	40	0.0%	1	39	2.5%
Total		3,419	289,105	1.2%	8,629	283,895	2.9%

The Remaining Capacity columns in Table 3-3 represent the remaining capacity of the derated affected facilities once the energy penalty is applied to each unit, assuming that all affected facilities undergo a cooling system retrofit.

Scenario Analysis – Retrofit and Retirement Assumptions

Without a plant-by-plant investigation, DOE does not have meaningful information that would allow a projection of which of the facilities subject to a retrofit mandate would not be retrofitted for economic reasons. Generally, older units may not have sufficient useful operating life remaining to recover the retrofit investment. Also, less efficient generation facilities may not be operated enough hours of the year to justify the retrofit investment.

Therefore, the assumption of retiring all affected units with 35 percent or less utilization rate is used in this analysis as a proxy for retirements of all combustion generation units for both economic and siting reasons. Admittedly, the assumption likely underestimates the potential impact to many of the older baseload coal units.[69]

1. Economic Retirements

The new capital and higher operating costs associated with retrofitting a once-through cooling system may make it uneconomic for a plant to undergo a cooling system retrofit. DOE did not conduct an economic impact analysis of the capital and operating costs[70] associated with the retrofits as part of this analysis, nor did DOE consider the impact of increased capital and operating expenses on the economic dispatch of affected facilities and how that would impact the security and reliability of the Nation's grid. However, to provide a high-level view of potential economic impacts to financially marginal plants, a preliminary assessment was considered where capacity factor (CF) was used as a proxy for plants that may not be economic to retrofit.

The use of the capacity factor as a proxy for economic viability is assumed reasonable for this preliminary, order-of-magnitude analysis. Many factors would need to be considered to assess the economic viability at each individual plant, including typical costs associated with cooling equipment, balance of plant modifications, and engineering (including design safety margins, potentially applicable to nuclear facilities) and construction. Furthermore, permitting costs, land acquisition costs, and other "soft" costs

[69] Discussions with the Electric Power Research Institute (EPRI) provided several examples of coal fired facilities that appear likely to be at risk because of site specific considerations. While not intended as an exhaustive list, it clearly shows that all thermal generation units, including coal, may have site-specific constraints that could make compliance very difficult.

[70] While this analysis did not estimate facility costs of cooling tower retrofits, a recent NETL study (NETL, Cost and Performance Baseline for Fossil Energy Plants, Volume 1, DOE/NETL-2007/1281, August 2007, (http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf) identified recirculating wet cooling tower system costs at a greenfield facility of approximately $70/kW for a thermoelectric plant and $35/kW for a combined cycle plant. Considering that retrofit installations can be somewhat more difficult and costly than a greenfield construction, the costs associated with a complete cooling system retrofit could range as high as $100//kW. For a nominal 500 MW facility, retrofit costs could range from roughly $17.5 Million - $50 Million.

may also be relevant to the economic viability. Detailed analysis of individual factors on a plant-by-plant basis is beyond the scope of this analysis. However, potential space constraints are examined on a limited basis later in this report.

Similarly, this analysis did not attempt to project future costs to comply with other potential regulations, such as new ambient air standards and carbon reduction. Such other factors faced by individual generating facilities may result in early retirement not captured in this analysis and subsequently the total impact of a 316(b) rule could be even further underestimated. Ultimately, such facility-specific issues (both physical and economic) should be evaluated thoroughly prior to a final rule.

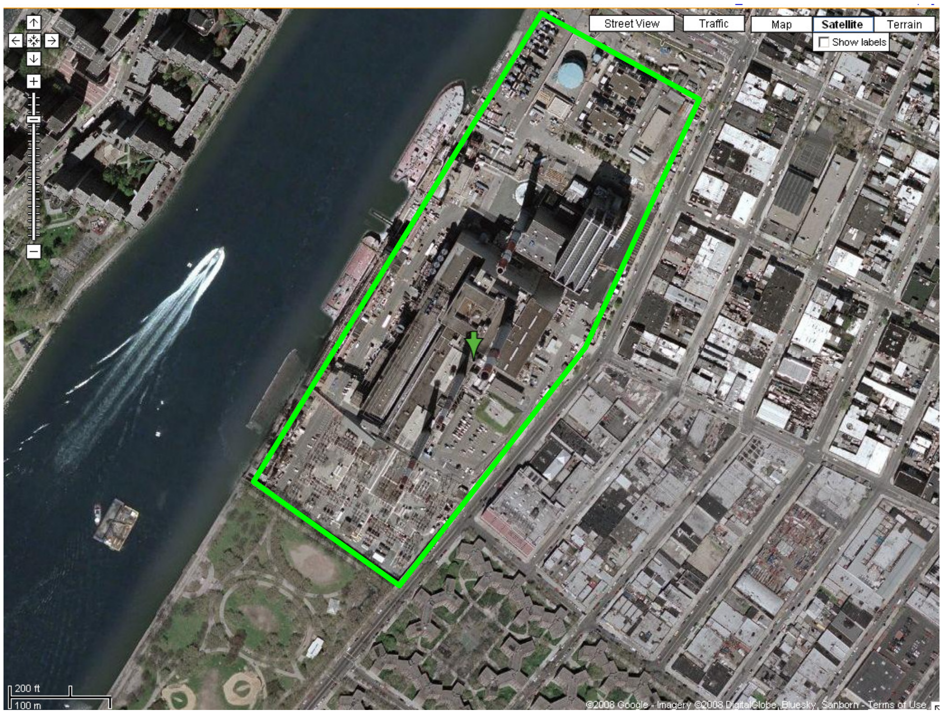
2. Siting/Permitting Retirements

- Siting Constraints

In addition to the nationwide NERC region analysis of capacity loses due to economic retirements, DOE also recognized the potential for capacity losses due to space limitations at existing facilities. While DOE identified a set of potentially affected facilities (see Table 3-1, row no. 6), it may not be feasible to retrofit the identified facilities because of land and space constraints. The New York (NY) NERC sub-region was used as an initial sample to evaluate potential space constraints for building the recirculating cooling retrofits. This region was chosen because it is highly urbanized and many of its generating units are within densely populated areas. The 26 identified facilities in the NY sub-region included in Table 3-1 were visually assessed using publically available satellite images.

The visual analysis was used to qualitatively identify obvious land constraints for a recirculating cooing system retrofit and did not consider any detailed surface features or ownership of any adjacent land. From the aerial view, it was determined that at least three of the 26 plants located in the NY sub-region have apparent land constraint issues. The three plants produce a total of 3,066 MW and have capacity factors greater than 60 percent. Figure 3-4 is a Google aerial view of the Ravenswood plant along the East River in Queens, New York City. The plant produces 1,827 MW with natural gas- or oil-fired steam turbines and uses once-through cooling. The overall plant area is heavily crowded, constrained by the river on the west, buildings to the north, east and south, and by a park to the southwest. The plant site itself is congested by many buildings a substation switchyard and parking lots.

Figure 3-4. Land Constrained Plant – Ravenswood Plant[71]



Using the capacity factor criteria as a proxy for retirement, two of the three units at the Ravenswood plant would be retrofit and continue to operate. However, the aerial image suggests that there may be significant facility-specific constraints to the retrofit of a recirculating cooling system.

New York City is perhaps the country's most highly congested load pocket, with peak summer locational prices regularly exceeding $1,000/MW. Removing 1,000 MW or more from the city would have obvious deleterious consequences, for both price and associated power scarcity. Other plants that share the space and logistical constraints of Ravenswood may have similar value to their regions.

- Permitting Constraints

This analysis is not able to reach quantitative conclusions on the location and number of facilities that could not obtain the requisite permits and water rights required to construct cooling towers. For example, the 482-MW Mirant Potomac River Power located next to the flight path into Ronald Reagan Washington National Airport and which supplies electric power to much of downtown Washington, D.C., would be unlikely to install cooling towers due to both space and permit restrictions.

[71] Source: Google Maps, http://maps.google.com , last accessed June 2008.

Estimate of Generation Capacity Losses

Using the assumptions for energy penalty and retirements discussed above, three cases were considered:

- **Case 1** – 100 percent retrofit;
- **Case 2** – Only facilities with a capacity factor greater than 25 percent would retrofit, those below the 25 percent capacity factor threshold were assumed to retire; and
- **Case 3** – Only facilities with annual capacity factor greater than 35 percent would retrofit, those below the 35 percent capacity factor threshold were assumed to retire.

The rationale for capacity factors as a proxy for economic viability is that it is assumed that plants with low average annual capacity factors are uneconomical to dispatch and are therefore candidates for retirement. Some of these plants, however, may be operated relatively intensively during peak months, especially those near areas of high demand.

In conducting the analysis, DOE considered a retirement range, where the low retirement case (Case 2) and high retirement case (Case 3) were bracketed by the upper and lower bounds of two conceptual approaches to the capacity factor.[72] The first concept, CF1, based as reported by EIA on the Form 767, is percentage annual hours that the affected boiler unit is online, that is:

CF1 = hours of boiler unit operation/8760

The second concept, CF2, refers to generation as a percentage of nameplate capacity, or to asset utilization as a percentage of its potential output, namely:

CF2 = annual generation (Mwh)/(capacity (MW) x 8760), where 8760 is the total number of hours in a year.

[72] The two concepts are derived from the type of data reported in EIA Form 767, specifically "Boiler Hours Under Load" and "Total Net Electrical Generation - Annual". As the illustration indicates, the two concepts result in different conclusions when used as a proxy for economic viability of a cooling system retrofit. For the cases considered here, the limiting concept was applied (i.e., CF1 for the low retirement case and CF2 for the high retirement case).

An example of the difference between CF1 and CF2 can be illustrated by Units 2 and 3 of the Arthur Kill generating station in New York. Both units are steam turbines fueled by natural gas. Their 2005 output is given below:

Table 3-4. Example Comparison of Capacity Factor Concepts

Unit	Nameplate Capacity	2005 Generation (MWh)	Unit Load Capacity Factor (CF1)	Annual Generation Capacity Factor (CF2)
Arthur Kill Unit 2	376	752,902	0.75	0.23
Arthur Kill Unit 3	536	605,337	0.41	0.13

Based on CF1, neither unit would be retired; based on CF2, both would be. An attempt was made to see whether reported locational marginal prices of the NYISO justified the operation of plants with CF2 < 0.35. The exercise indicated these plants did not make profits from energy revenues, but DOE had no way of determining whether such plants received ancillary payments or other reimbursements for reserve status, etc. Thus the question of whether any given plant is economic can not be answered by this analysis. Nonetheless, the 35 percent threshold for CF2 may serve as a useful threshold for economically constrained units.

For each NERC region, DOE evaluated the possible loss of system capacity from unit retirement and de-rate occurring at the highest ambient conditions at the remaining retrofitted facilities. The lost capacity was then compared to the expected 2015 regional capacity and load from the Energy Velocity database, which in turn is based on the NERC 2007 Long-Term Reliability Assessment. Results from the three cases for the NERC regions and the WECC-California, New York-ISO, and ISO-New England sub-regions are presented in Table 3-5.

Table 3-5. Potential Loss of Generating Capacity in 2015, Selected NERC Regions

Region	2015 Expected Capacity (MW)	Case 1		Case 2			Case 3		
		Derate at Retrofitted Facilities (MW)	Percent Reduction of 2015 Expected Capacity	Retired Capacity (MW)	Derate at Retrofitted Facilities (MW)	Percent Reduction of 2015 Expected Capacity	Retired Capacity (MW)	Derate at Retrofitted Facilities (MW)	Percent Reduction of 2015 Expected Capacity
WECC-CA	59,694	-446	-0.7%	-8,798	-246	-15.2%	-13,128	-149	-22.2%
WECC-TOT	151,136	-468	-0.3%	-8,912	-265	-6.1%	-13,242	-168	-8.9%
ERCOT	81,307	-738	-0.9%	-15,129	-373	-19.1%	-19,776	-261	-24.6%
RFC	222,732	-2636	-1.2%	-3,152	-2,541	-2.6%	-7,179	-2,423	-4.3%
SERC	254,993	-2531	-1.0%	-4,796	-2,413	-2.8%	-16,194	-2,135	-7.2%
NYISO	33,353	-634	-1.9%	-3,307	-532	-11.5%	-8,708	-364	-27.2%
ISO-NE	30,056	-467	-1.6%	-2,091	-402	-8.3%	-5,040	-310	-17.8%
NPCC-US	63,410	-1,101	-1.7%	-5,398	-934	-10.0%	-13,748	-674	-22.7%
MRO	47,545	-519	-1.1%	-240	-511	-1.6%	-529	-502	-2.2%
SPP	55,583	-222	-0.4%	-817	-201	-1.8%	-1,166	-193	-2.4%
HAWAII	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FRCC	59,473	-372	-0.6%	-303	-365	-1.1%	-3,114	-297	-5.7%

These losses can be compared to regional capacity and expected load in, say, 2015, which could be a compliance year for any new 316(b) rule. Table 3-6 compares the remaining capacity for the regions evaluated with the expected load for 2015. Table 3-6 also illustrates the remaining capacity margins for each of the regions evaluated, and compares the scenario results to the projected capacity margin absent a restrictive 316(b) ruling (No Rule).

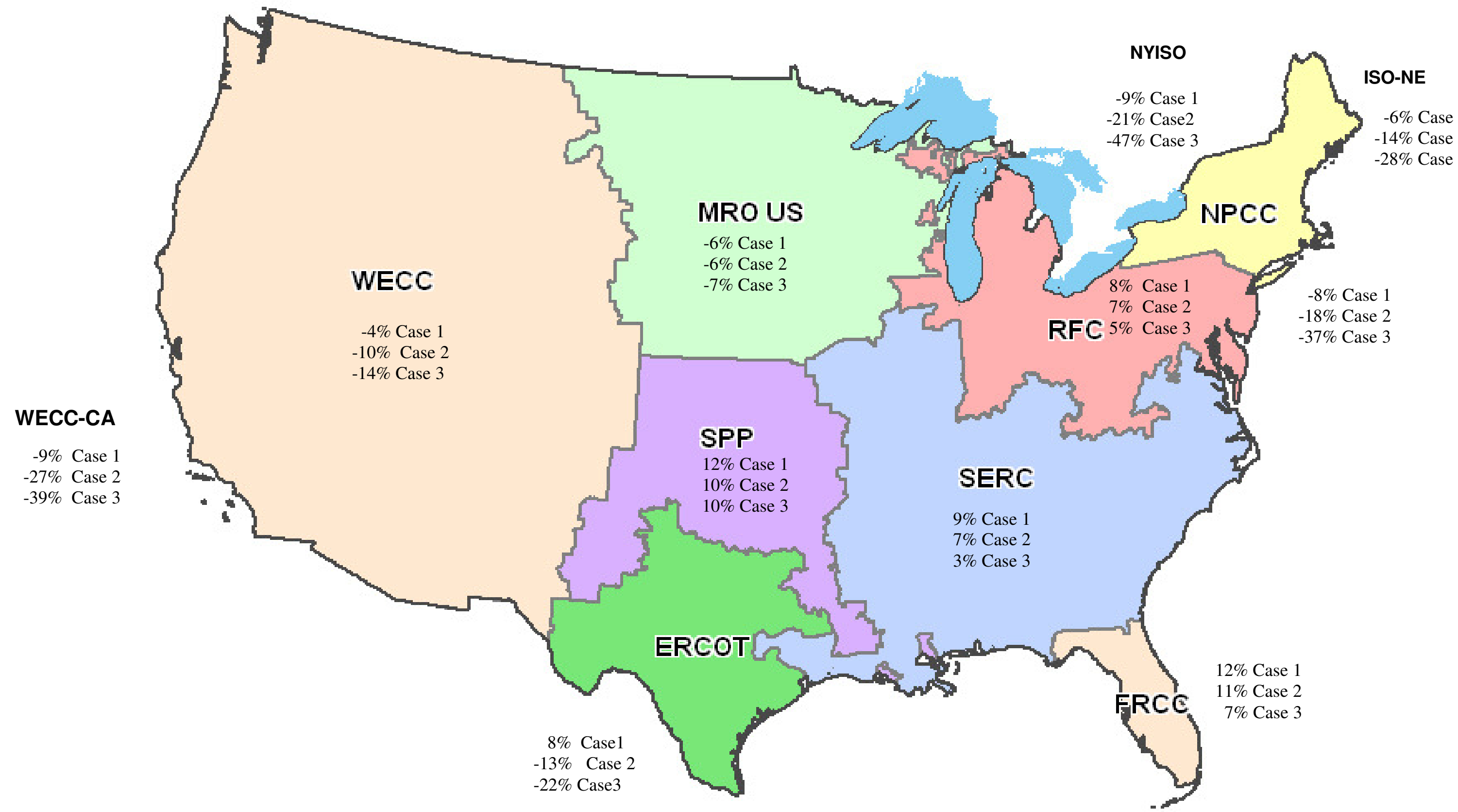
Table 3-6. Capacity Loss and Capacity Margins

Region	2015 Expected Capacity (MW)[1]	Remaining Capacity (MW)			2015 Expected Load (MW)[2]	Capacity Margins[3] (Percent)			
		Case 1	Case 2	Case 3		Case 1	Case 2	Case 3	NERC LTRA[4]
WECC-CA	59,694	59,248	50,650	46,417	64,308	-9%	-27%	-39%	-5%
WECC-TOT	151,136	150,668	141,959	137,726	156,408	-4%	-10%	-14%	0%
ERCOT	81,307	80,569	65,805	61,270	74,471	8%	-13%	-22%	15%
RFC	222,732	220,096	217,039	213,130	202,400	8%	7%	5%	13%
SERC	254,993	252,462	247,784	236,664	229,636	9%	7%	3%	14%
NYISO	33,353	32,719	29,514	24,281	35,669	-9%	-21%	-47%	2%
ISO-NE	30,056	29,589	27,563	24,706	31,510	-6%	-14%	-28%	0%
NPCC-US	63,410	62,309	57,078	48,988	67,179	-8%	-18%	-37%	1%
MRO	47,545	47,026	46,794	46,514	49,615	-6%	-6%	-7%	3%
SPP	55,583	55,361	54,565	54,224	48,934	12%	10%	10%	17%
HAWAII	N/A	N/A	N/A	N/A	N/A[5]	N/A	N/A	N/A	N/A
FRCC	59,473	59,101	58,805	56,062	52,266	12%	11%	7%	13%

Notes:
1. 2015 expected capacity per EV database, 6/2008. Expected capacity = operating capacity+standby+under construction+permitted, as of 8/2008.
2. 2015 expected load derived from NERC forecast Net Internal Demand, EV database 6/2008. Does not include proposed plants that did not have siting permits as of 8/2008.
3. Capacity Margins used here is calculated for each NERC region as [1 – (2015 Remaining Capacity/2015 Expected Load) x 100]. It does not include forecast electricity imports, firm or otherwise.
4. NERC, 2007 Long-Term Reliability Assessment 2007-2016, October 2007.
5. Hawaii did not report forecast load.

Figure 3-2 graphically presents the results from the three cases and the NERC LTRA. Adequate additional electric generation and transmission capacity is required to meet unanticipated demand or unplanned facility losses. Surplus electric generation capacity is required that may quickly be dispatched to match load and to maintain system reliability. The amount of capacity held in reserve, expressed as a percent of peak demand, is called the net capacity reserve margin or reserve margin. Reliable system operation requires a net reserve margin (native generation plus contracted imports) of 10 to 15 percent. The percentage of reserve margin that may be appropriate for a control area varies depending on the generation mix, the load variability, and the interconnectivity of the system with that of adjacent systems. Reserve margin may, or may not, include capacity generated outside the control area. The reserve margins presented in this paper do not include capacity generated outside the control area.

Figure 3-2. NERC Region Map - Potential 2015 Capacity Margins



Chapter 4: Electricity Reliability Scenario Analysis

One measure of electricity reliability is the reserve capacity margin, which measures the bulk power system's ability to satisfy consumers' energy demand in the event of unplanned outages, inclement weather, or other problems. The Office of Electricity Delivery and Energy Reliability requested that NERC assess the reliability impacts that would result from reduced reserve capacity due to retrofitting and retirement cases described in Chapter 3, above. In response, NERC prepared a white paper entitled, "2008-2017 NERC Capacity Margins: Retrofit of Once-Through Cooling Systems at Existing Generation Facilities" (NERC White Paper), which is provided as an appendix to this analysis.

NERC's analysis evaluates the different reserve capacity margins resulting from a reference case with no system changes and a case where the effects of implementing 316(b) regulations are simulated. DOE requested that NERC assume, for purposes of their assessment, that closed-loop cooling systems will be added to all nuclear units, that generation facilities having less than a 35 percent capacity factor will be retired (Case 3) and that no replacement capacity will be built. DOE did not request that NERC evaluate the lower retirement case (Case 2), after concluding that the lower retirement case would simply provide results that would fall between the range of outcomes defined by no mandate and the more significant Case 3 scenario.

NERC White Paper

Using the assumptions defined by DOE for this assessment, NERC determined that capacity reductions due to auxiliary loads caused by equipment retrofitting are about 9,300 MW. In addition, approximately 39,500 MW of capacity resources are eliminated by generation unit retirements under Case 3. NERC's analysis concludes that, across all NERC U.S. regions, that the potential loss of 49,000 MW from the retrofitting energy penalties and premature unit retirements would reduce the NERC-US generation capacity resources by 4.3 percentage points.

However, NERC emphasizes that the reductions in reserve capacity margin would be different in each region and have very different impacts on the electricity reliability in each region depending on the vintage and design of their units. (*See* NERC White Paper, Figure 3, and Figure 3-3, *infra*). NERC identified the regions with the highest generation capacity losses as Texas, New York/New England, California, and the Southeast.

> The WECC-CA US sub-region sees the largest impact with a reduction of almost 15 percent (10,400 MW), significantly reducing their summer peak capacity margin. NPCC-New England also experiences a significant impact of 10.3 percent. This impact may be the result of the abundant gas-fire plants which have low capacity factors in this assessment indicating a retrofit would not be economically suitable.

> ERCOT faces the most substantial impact at the regional level. Retirement and retrofit effects may result in a loss of up to 11,500 MW, reducing their margins almost 13 percent.
>
> Some regions starting above the NERC Reference Margin Level in the *Reference Case* fall below as a direct result of this analysis: ERCOT, RFC, and SERC. These regions may require additional resources to accommodate the potential retirements/retrofits from the Section 316b Phase II action.
>
> Similarly, the full region of SERC shows a total capacity reduction of about 9,300 MW, most coming from the SERC-Delta (South-Central U.S.) sub-region. However, the impact on the Adjusted Potential Resources capacity margin is only 3 percent due to its overall large demand and capacity base line in the *Reference Case* for the region.

NERC also noted in its conclusions that transmission congestion and reliability might be aggravated and detailed system transmission studies may be needed to determine bulk power system reliability resulting from the loss of the specific units studied.

Discussion

The Nation's electricity industry faces major challenges during the next decade or more to keep adequate reserve capacity margins of electricity generation available to meet peak demand growth, even if that peak demand growth is dampened by initiatives focused on demand-response, improved technology, and energy efficiency.

With little increase in hydroelectric generation and only modest growth in nuclear power expected by 2020, EIA projects new electricity demand will be met primarily by coal and renewable energy. However, the magnitude of new coal generation that is actually put in service may be limited by siting restrictions, emissions limits, and RPS pressures. At this time, it does not appear that there will be significant penetration of commercial-scale CCS projects prior to 2020. Alternative energy and conservation will make important contributions in replacing lost generation. Nevertheless, it appears that combined-cycle natural gas generation, which is dependent on LNG imports on the margin, will be required to meet new electricity demand and to replace retirements of existing generation facilities, whether planned or the result of a cooling tower mandate or other regulatory measure.

Regarding the existing fleet of thermoelectric power plants (fossil and nuclear combined), DOE estimates that over half – nearly 300 gigawatts (GW) – are equipped with once-through cooling systems. This represents 385 existing power plants that could be affected by 316(b) Phase II regulations. The majority of the affected facilities (roughly 70 percent) are baseload steam plants, predominantly coal and nuclear facilities. The remaining 30 percent are mostly older, less efficient oil- and gas-fired steam units.

Since retrofitting to a recirculating cooling system at a facility originally designed for once-through cooling will result in reduced power output, this overall loss of capacity (energy penalty) has been modeled for this analysis. However, practical considerations did not permit this analysis to conduct a facility-by-facility investigation to determine how many facilities could not or would not meet the cooling tower mandate. Potential retirements due to economic considerations or site and permitting restrictions are roughly estimated by using a proxy assumption that the cooling tower mandate would cause the retirement of all affected units operating between 25 percent of the time or less, and 35 percent of the time or less (see Table 3-5). Although this range of retirements may underestimate the amount of generation capacity that would be retired, it provides a perspective on the reliability impacts that would result from this range of plant retirements.

Nuclear plants would be particularly impacted by a cooling tower mandate because re-evaluation of the nuclear plant safety basis and Nuclear Regulatory Commission (NRC) licensing amendments would be required for existing nuclear reactors to comply with such a rule. This is in addition to the engineering, construction, outage, and power replacement impacts and loss of revenue similar to large, baseload coal plants. The licensing impact would be determined by the complexity of necessary design changes to safety and non-safety cooling systems, preparation of required license application documentation and supporting analyses, submission of the license amendment package, and the review and approval by the U.S. Nuclear Regulatory Commission. The potential for significant negative economic impact could influence utilities to not pursue further license renewals based on unfavorable financial returns, further reducing electricity grid operating margins. During Fiscal Year 2009, the Department of Energy will work with NRC and industry to better characterize the scope and impact of such a change to an operating nuclear plant.

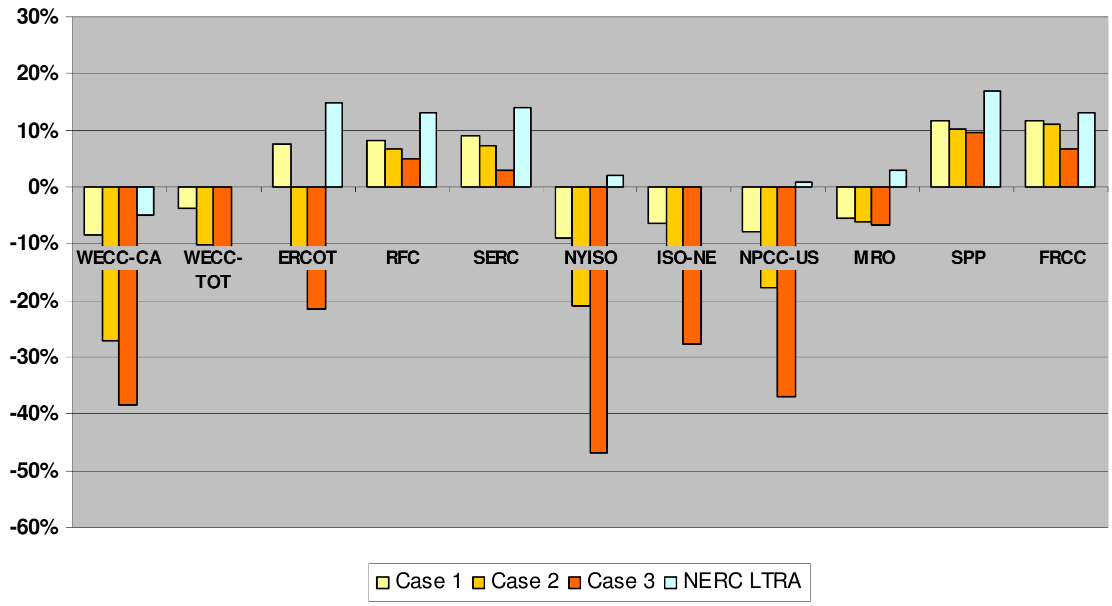
Although the proxies used in the DOE scenario analysis likely underestimate the potential impact of the mandate on many baseload coal and nuclear units, they are used in this analysis to provide rough approximations of possible retirement scenarios from a cooling tower mandate. The analysis indicates that, on a national basis, a cooling tower mandate would cause a relatively modest reduction (46,000 to 81,000 MW)[73] in available generating capacity which has a total capacity of over 1,000,000 MWs. The U.S. does not have a national electricity grid, but rather a series of large regional power grids. The amount of reduced generation capacity and its impact on regional reliability would vary from region to region. While a number of NERC regions likely have adequate capacity margins to accommodate such a reduction, certain sub-regions, particularly the New York, New England, and California NERC sub-regions, could suffer significant capacity margin reductions. The overall impact of the decreased capacity margin could result in impaired reliability during critical periods (peak summer demand) in these already at-risk regions.

Similarly, DOE's independent analysis of changes in capacity margins for the NERC subregions demonstrated concerns for reliability in similar subregions. Note that in

[73] DOE's total projected retired capacity plus derate from Cases 2 and 3. See Table 3-5.

DOE's analysis it assumed no new generation would be constructed where NERC's analysis assumed planned construction would go into service as scheduled. Nevertheless, DOE's results are illustrative of the potential reliability issues that could occur under a cooling tower mandate. DOE's results are depicted in Figure 4-1.

Figure 4-1. Potential 2015 Capacity Margins for the three cases evaluated and from NERC's Long Term Reliability Assessment (LTRA)



Case assumptions:

- Includes only native generation
- No new facilities constructed
- No replacement of derated or retired

Source: NETL, 2008

Figure 4-1 clearly indicates that under this analysis, a national cooling tower mandate would result in a range of impacts to capacity margins across the various NERC regions. Many of the regions are significantly impacted, and ERCOT, NPCC, and WECC margins plunge in the worst case. Potentially more significant is that four of the eight regions (ERCOT, MRO, NPCC, and WECC) result in a capacity deficit in nearly all of the cases evaluated. These regions are affected more because of their relatively high use of older oil and gas steam turbines.

Generally, older units may not have sufficient useful operating life remaining to recover the retrofit investment. Also, less efficient generation facilities may not be operated enough hours of the year, i.e., have too low a capacity factor, to justify the retrofit investment. Within the scope of this analysis, DOE cannot precisely estimate the number of existing generation facilities that would retire rather than meet retrofits required to meet new SO_x, NO_x, mercury, or carbon emission limits. However, it is clear that a significant number of base-load coal generation facilities will not be economic under the burden of the cumulative capital and operational costs of complying with new air emissions limitations in addition to the capital costs and energy penalties caused by a cooling tower mandate. Similarly, some nuclear facilities may determine it is not economic to comply due to the cumulative costs of complying with such a rule, including amending their license and the loss of revenue during retrofit.

If those generation facilities that could not or would not meet a mandatory cooling tower standard were retired, the loss of existing generation capacity would be in addition to the energy penalties that reduce the nameplate capacity of the facilities that do construct cooling towers, as discussed in Chapter 3.

Construction of hundreds of cooling towers over the next six or so years would obligate financing, construction materials, and labor at a time when these resources are in competition with new energy infrastructure facilities needed to meet increasing demand while reducing ambient air emission and greenhouse gases. Construction would require a prolonged outage period for many existing units, as each unit is transitioned from one cooling system to another. Depending on when these outages occur, and for how long, the outages may jeopardize the ability of electricity suppliers to meet peak demand. These types of outages are typically scheduled during periods of reduced demand. Avoiding plant closures during peak demand periods may not be possible based on the deadlines of the mandate, time for permit approvals, or availability of construction firms and materials. Nuclear plants, in particular, may be forced to suspend generation for substantial periods during construction and tie-in of cooling towers. In its Phase I Report on Old Thermal Generation (2008-2012)," (February 2008), CAISO provided a detailed analysis of the reliability dangers caused by requiring too many facilities to retrofit or retire too quickly.

The California Independent System Operator Corporation (CAISO) has been analyzing the impact of cooling tower mandates on electricity reliability in the State of California in response to actions by the California State Water Resources Control Board (SWRCB) proposing to implement section 316(b) for the State as a cooling tower mandate. In its February 2008 Old Thermal Generation Report, cited above, CAISO found that approximately 40 percent of California's entire in-State generation capacity would be subject to SWRCB's proposed cooling tower rules.[74]

In its comment letter to the SWRCB dated May 20, 2008,[75] CAISO warns that increasing electricity imports into a region to replace loss of capacity from the loss of once-through-cooling generation with low utilization rates would create serious grid and delivery reliability problems, including voltage and frequency support, stabilization of system dynamics, emergency local power when import lines are interrupted, loss of critical back up ("Reliability Must Run") units, and loss of WECC required Contingency Reserve capacity.

Additionally, CAISO notes in its May 20 letter that units with low capacity factors that are capable of ramping, load flowing, and regulation services are increasingly important

[74] (http://www.caiso.com/1f80/1f80a4a5568f0.pdf)
[75] (http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316_may08_comments.shtml).

to achieve the reliable integration of increased wind and solar generation. Some of the once-through-cooling units that CAISO believes are "at risk from retirement [due to the SWRCB cooling tower mandate] are those expected to provide the services required to maintain reliable operation in order to accommodate wind power and renewable resource integration capability for ramping and load following." CAISO concludes that the loss of these units may present serious reliability concerns, especially during peak conditions and localized emergencies, such as the 2007 San Diego fires, and increase the likelihood of localized blackouts or load shedding.

Recently, WRCB announced further hearings, opportunities for public comment, and workshops prior to taking action on the once- through cooling ban. (Power Market Today, August 4, 2008.[76]

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[76] (http://www.waterboards.ca.gov/water_issues/programs/npdes/cwa316.shtml#otc).

Chapter 5: Conclusion

A National mandate requiring the installation of cooling towers (recirculating water cooling) at all existing thermal electric generators with once-through-cooling of 50 MGD or greater would require construction of cooling towers at 385 existing fossil and nuclear electric generation facilities. The direct and indirect effects of this action would be to reduce electric generation capacity throughout the country at a time the electric industry faces major challenges to maintain adequate reserve margins. A loss of efficiency of 1 to 4 percent would occur at each retrofitted electric generation unit due to increased ancillary load to power pumps, fans, and other equipment, and to the reduced efficiency of recirculated water compared to once-through cooling water. In addition, a number of existing facilities would be unable to retrofit to cooling towers because of space limitations or the inability to acquire requisite permits or water rights. For this analysis, it is assumed that those facilities would be required to cease operation. Also, owners of older less efficient units may choose to retire units rather than to complete the cooling tower retrofits, especially if other retrofits may also be required to meet new SO_x, NO_x, mercury, and carbon limits.

DOE requested NERC to review the impact of retrofitting potentially affected facilities with existing once-through-cooling systems to closed-loop cooling systems. NERC assumed a 4 percent reduction in nameplate capacity of steam units due to the energy penalty of cooling tower systems combined with a presumed unit retirement if the capacity factor is less than 35 percent. The analysis was conducted NERC-wide for the period of 2008-2017. NERC concludes that nationally, net capacity reserve margins may be reduced up to 4.3 percentage points. Transmission congestion and reliability might be aggravated and detailed system transmission studies may be needed to determine bulk power system reliability resulting from the loss of the specific units studied. The congestion in the Mid-Atlantic Area National Interest Electric Transmission Corridor would likely be exacerbated

The impact of this cumulative lost existing generation capacity would vary from region to region. The net capacity reduction would have a disproportionately large affect on those regions where reserve capacity is already low. This loss of generation capacity in combination with the early retirement of facilities that either cannot retrofit or choose for economic reasons not to retrofit may jeopardize the ability of California, New York, and New England to meet peak electric demand over the next decade.

Construction of hundreds of cooling towers over the next six years would obligate financing, construction materials, and labor at a time when these resources are in competition with new energy infrastructure facilities needed to meet increasing demand while reducing ambient air emissions and greenhouse gases. Construction could require a prolonged outage period for some existing units as they are transitioned from one cooling method to another. Depending on the timing of these outages and their duration, they may jeopardize the ability of certain sub-regions to meet peak demand.

Finally, additional generation and transmission capacity would be required to replace the lost capacity caused by the outages during retrofit, lost efficiency, and forced or economic retirements. Some of that capacity may be replaced by conservation and demand response initiatives. Nevertheless, new conventional generation, some of it sited near the retired plants to maintain load-following capabilities, would also be required. Based on recent construction history, it is presumed that these conventional generation facilities would be natural gas-fired. This additional capacity may be dependent on LNG imports that are vulnerable to potentially high global prices.

APPENDIX

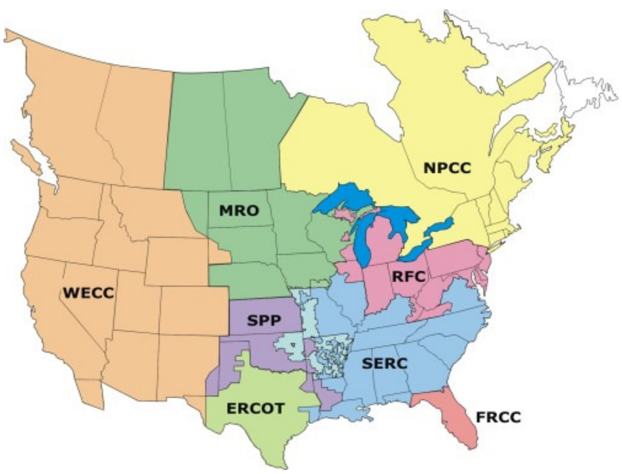
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2008-2017 NERC Capacity Margins:

Retrofit of Once-Through Cooling Systems at Existing Generating Facilities

Background

The North American Electric Reliability Corporation's (NERC) mission is to ensure the bulk power system in North America is reliable. To achieve this objective, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future adequacy; evaluates owners, operators, and users for reliability preparedness; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants that form its various committees and sub-committees. It is subject to oversight by governmental authorities in Canada and the United States (U.S.)[77]



ERCOT Electric Reliability Council of Texas	**RFC** Reliability*First* Corporation
FRCC Florida Reliability Coordinating Council	**SERC** SERC Reliability Corporation
MRO Midwest Reliability Organization	**SPP** Southwest Power Pool, Incorporated
NPCC Northeast Power Coordinating Council, Inc.	**WECC** Western Electricity Coordinating Council

NERC assesses and reports on the reliability and adequacy of the North American bulk power system divided into the eight regional areas. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the U.S., Canada and a portion of Baja California, Mexico.

[77] On June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce reliability standards with all U.S. owners, operators, and users of the bulk power system, and made compliance with those standards mandatory NERC has similar authority in Ontario and New Brunswick, and is seeking to extend that authority to the other Canadian provinces. NERC will seek recognition in Mexico once the necessary legislation is adopted.

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NERC's primary role in providing reliability assessment is to identify areas of concern to the reliability of the North American bulk power system and to make recommendations for their remedy. NERC cannot order construction of additional generation or transmission or adopt enforceable standards having that effect, as that authority is explicitly withheld by Section 215 of the U.S. Energy Policy Act of 2005[78]. In addition, NERC does not make any projections or draw any conclusions regarding expected electricity prices or the efficiency of electricity markets. The enclosed Special Reliability Assessment provides a high-level view of future resource adequacy.

Special Reliability Assessment[79]

Upon a request from the U.S. Department of Energy's (DOE) Offices of both "Electricity and Energy Reliability" and "Fossil Energy," NERC measured the affects on capacity margins resulting from retrofitting existing plants with open-loop cooling systems to closed-loop systems, or retiring them. This special reliability assessment is part of DOE's response to the U.S. Senate Subcommittee on Energy and Water Appropriation's request to identify the impacts of EPA's rulemaking on Section 316b of the Clean Water Act.

Approach - Preliminary 2008-2017 Long-Term Reliability Assessment data was used (*Reference Case*). The data includes U.S. summer peak demand and capacity. Though this data is subject to change, NERC does not believe any future data enhancements will materially change the assessment results. Specific unit information was received from the U.S. Department of Energy, and EPA Section 316b permitting dates were received from the Edison Electric Institute (EEI), providing the year a decision is required.

Capacity Resources & Margins

Net Internal Demand (MW) — Total Internal Demand reduced by dispatchable controllable (capacity) demand response.

Total Internal Capacity — The Sum of Existing (both Certain and Uncertain) and Planned Capacity.

Existing Capacity
a) Certain — Existing capacity resources reasonably anticipated to be available and operate and that are deliverable to or into the region.
b) Uncertain — Includes mothballed generation and portions of variable generation not included in "Certain"

Planned Capacity — Capacity resources expected to be available for the 2008-2017 Summer peak conditions that have achieved one or more of the following milestones:
a) Construction has started
b) Regulatory permits approved
c) Approved by corporate or appropriate senior management

Proposed Capacity — Capacity resources not listed in the prior categories, but has been identified through one or more of the following sources:
a) Corporate or appropriate senior management announcement
b) Included in integrated resource plan
c) Generator Interconnection Queues

Capacity Purchases and Sales – the following categories may be applied to existing and future capacity calculations.
a) Firm
b) Non-Firm
c) Expected
d) Provisional

Existing Capacity, Planned Capacity and Net Firm Transactions (MW) — Existing capacity resources reasonably anticipated to be available and operate and that are deliverable to or into the region plus net Firm Purchases/Sales.

Net Capacity Resources (MW) — Total Internal Capacity, less Transmission-Limited Resources, all Derates, Energy Only, and Inoperable resources; plus net Firm, Expected and Provisional Purchases/Sales. Net Capacity Resources do not include Non-Firm Purchases/Sales.

Adjusted Potential Resources (MW) — Net Capacity Resources, Existing Uncertain Resources less all Derates, Total Proposed Resources reduced (multiplied) by a confidence factor (percentage); plus Net Non-Firm and Provisional Transactions.

Net Capacity Resources Margin (%) — Net Capacity Resources reduced by the Net Internal Demand; shown as a percent of Net Capacity Resources.

Adjusted Potential Resources Margin (%) — Adjusted Potential Resources reduced by the Net Internal Demand; shown as a percent of Adjusted Potential Resources.

78 http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_bills&docid=f:h6enr.txt.pdf
79 This Special Reliability Assessment was approved by NERC's Board of Trustees on September 8, 2008

Reliability is measured by comparing Adjusted Potential Resource Margins between the summer peaks from the 2008-2017 Long-Term Reliability Assessment *Reference Cases* to a case with capacity changes resulting from EPA's Section 316b regulations.

> **Adjusted Potential Resources (MW)** — Net Capacity Resources, Existing Uncertain Resources less all Derates, Total Proposed Resources reduced (multiplied) by a confidence factor (percentage); plus Net Non-Firm and Provisional Transactions.
>
> **Net Capacity Resources Margin (%)** — Net Capacity Resources reduced by the Net Internal Demand; shown as a percent of Net Capacity Resources.
>
> **Adjusted Potential Resources Margin (%)** — Adjusted Potential Resources reduced by the Net Internal Demand; shown as a percent of Adjusted Potential Resources.
>
> **Region/Sub-region Target Margin (%)** — a suitable objective to maintain available capacity resources, determined largely by the type of generation that exists in the region.
>
> **NERC Reference Margin Level (%) —** either the Target Capacity Margin provided by the region/sub-region or NERC assigned based on capacity mix (i.e. thermal/hydro)

Capacity margins are used to measure the need for additional resources and serves to measure the bulk power system's ability to supply the aggregate electric power and energy requirements of the electricity consumers, accounting for scheduled and reasonably expected unscheduled outages of system components. Capacity margins measure supply that could be available to cover random factors such as generating equipment force outages, demand forecast errors, weather extremes, and capacity service schedule slippage.

Capacity margin is calculated by reducing the peak capacity by peak demand and normalizing it by peak capacity. Capacity margins are expressed as percent and reference margins are calculated using the peak load and capacity of the *Reference Case*.

Assumptions – The following assumptions were used in this assessment:

Assumptions specified by DOE:

- Close-loop cooling systems will be added to all nuclear units.
- Capacity factors can be used as a proxy for economic suitability for retrofit
- Unit Retirements/Retrofits were based on capacity factors from 2006:
  - Units with a capacity factor less than 0.35 are assumed to be retired.
  - Units with a capacity factor greater than or equal to 0.35 were derated by 4 percent of maximum rated (nameplate) capacity.
  - 60 percent of retirements/retrofits was projected to begin in 2013, 20 percent in 2014 and 20 percent in 2015.
- Plants deemed "difficult to retrofit" due to geographical limitations (i.e. land-locked, space and permitting constraints) could result in early retirement.[80] This assessment does not assume their early retirement.
- No new plants are built to replace capacity lost to retired units or auxiliary loads.
- Retrofits are instantaneous, with no capacity short-falls due to plant shutdowns.

[80] Identifying plants that are "difficult to retrofit" would necessitate a site-specific survey of all plants with open-loop cooling systems. While this assessment does not provide site-specific analysis, some plants with capacity factors greater the 0.35 have been identified as "difficult to retrofit", such as, Eddystone #1 and #2, Fisk Street, Joliet 9 and 29, Crawford, and Will County.

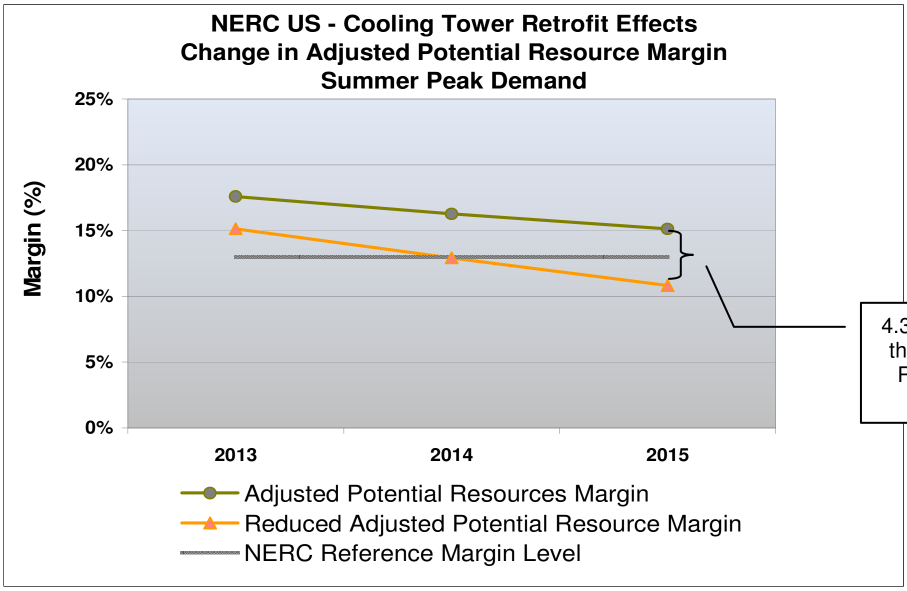
- Plants with a zero capacity factor (inactive or not yet built) are not assessed. These plants are not included in the region's *Reference Case*.

Assumptions specified by NERC:

- The NERC Reference Margin Level adopted the regional/subregional Target Capacity Margin. If not available, the NERC Reference Margin Level is based on supply-side fuel: 13 percent for thermal systems and 9 percent for hydro.
- Unit Retirement/Retrofit capacity reduction comparison is based against "Adjusted Potential Resources", calculated with all Existing Capacity and probable Planned Additions, Proposed Additions, and Net Transactions.
- Units already expected to retire between 2010 and 2015 were not considered part of the capacity reduction as they are already factored into the region's projections.[81]

The difference in Adjusted Potential Resources margins represents the percent reduction a region would experience over the three-year retirement and retrofit time period, based on the previously stated assumptions. Reliability assessment is performed only for the U.S Adjusted Potential Resource Capacity Margins measuring the region's capacity margin against a pre-specified target margin. Falling below the NERC Reference Margin Level may indicate the need for more resources, which, if not acquired, might suggest a higher risk to bulk power system reliability.

NERC-US Impacts - Based on the aforementioned assumptions, NERC-US impacts were calculated. U.S. resource margins drop from 14.7 percent to 10.4 percent when both the retired units and auxiliary loads due to retrofitting were compared to the *Reference Case* (see Figure 1).



4.3 percent reduction in the Adjusted Potential Resources Capacity Margin

Figure 1: NERC-US Summer Capacity Margin

[81] Plants expected to retire during this time frame with open-loop cooling systems represent a total capacity reduction of 9,500 MW.

NERC-US Regional/Subregional Impacts - Capacity resources for NERC regions are each impacted differently, depending on the vintage and design of their units. In Figure 3, the impact on summer peak capacity margins of retirements and retrofitting are provided.

A significant finding is the capacity reductions due to auxiliary loads and parasitic losses caused by equipment retrofitting is about 9,300 MW. Approximately 39,500 MW of the capacity resources are eliminated by unit retirements (see Figure 2). This 49,000 MW total capacity reduction in resources could reduce NERC-US capacity margins by 4.3 percent.

As a percent of the Adjusted Potential Resources margin, WECC-CA-MX US, ERCOT, NPCC-US, and the SERC-Delta sub-region see the largest impact as most units would be retired due to the low capacity factors units.

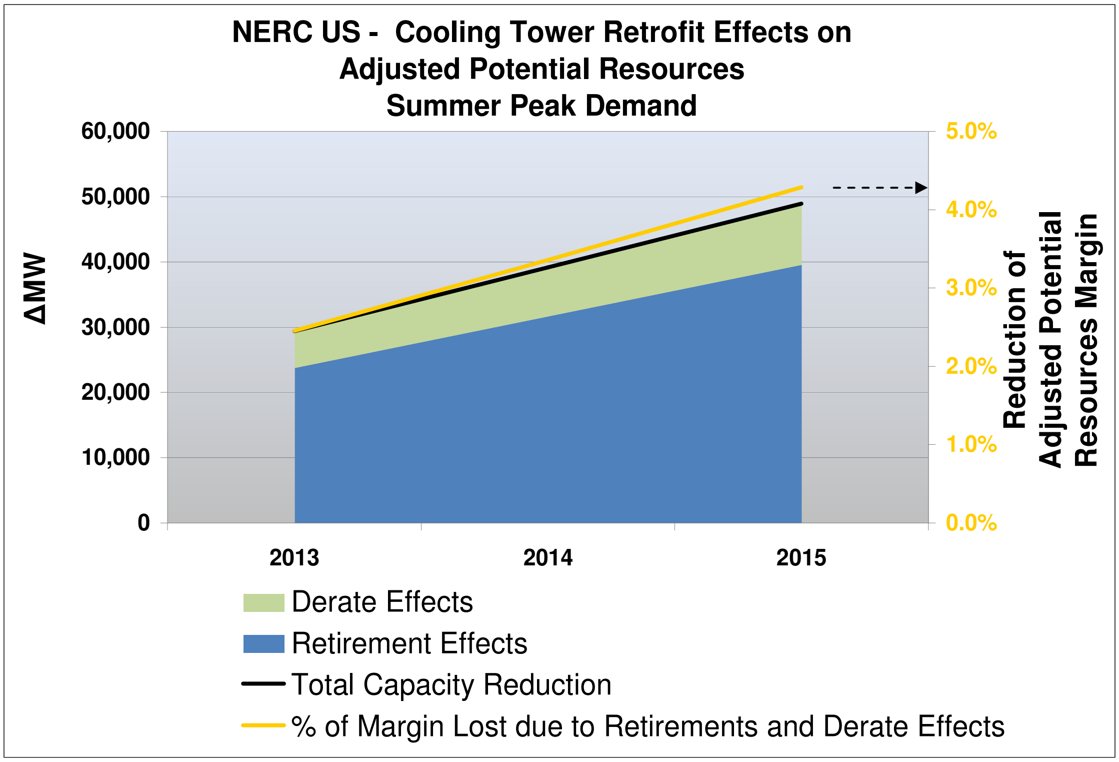


Figure 2: NERC-US Cooling Tower Effects

Table 1 provides a listing of regions/sub-regions whose capacity margins are impacted by plant retirements and retrofits. Note the capacity factor data provided by the U.S. Department of Energy was based on 2006 performance, where natural gas prices were increasing. Natural gas prices can drive capacity factors for gas-fired units and, therefore, many regions with a predominance of natural gas plants see more capacity margin reduction from plant retirements than those regions with plants fired by other fuels experiencing a 4 percent reduction in capacity to support auxiliary demand supporting retrofit equipment.

Table 1: 2015 US Summer Peak Retrofit/Retirement Effects

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

The WECC-CA US sub-region sees the largest impact with a reduction of almost 15 percent (10,400 MW), significantly reducing their summer peak capacity margin. NPCC-New England also experiences a significant impact of 10.3 percent. This impact may be the result of the abundant gas-fire plants which have low capacity factors in this assessment indicating a retrofit would not be economically suitable.

ERCOT faces the most substantial impact at the regional level. Retirement and retrofit effects may result in a loss of up to 11,500 MW, reducing their margins almost 13 percent.

Some regions starting above the NERC Reference Margin Level in the *Reference Case* fall below as a direct result of this analysis: ERCOT, RFC, and SERC. These regions may require additional resources to accommodate the potential retirements/retrofits from the Section 316b Phase II action.

† Adjusted Potential Resource Margins are subject to change, as updated capacity information is expected.

Similarly, the full region of SERC shows a total capacity reduction of about 9,300 MW, most coming from the SERC-Delta (South-Central U.S.) sub-region. However, the impact on the Adjusted Potential Resources capacity margin is only 3 percent due to its overall large demand and capacity base line in the *Reference Case* for the region.

Transmission Reliability Impacts - Though NERC did not perform detailed analysis of the transmission impacts resulting from the loss of capacity, it is expected that the volatility and predictability of intra-regional and inter-regional transmission limits could change. For example, NPCC-US experiences a potential reduction of up to 10 percent of their capacity margin due to unit retirements and auxiliary loads (7,500 MW) while RFC experiences a reduction of less than 3 percent (6,200 MW). System flows from West to East along the interface between RFC and NPCC-US already has shown congestion[82] and has been named a National Interest Electricity Transmission Corridor (NIETC).[83] One would expect that this capacity margin reduction could further aggravate the congestion on this corridor.

More transmission may also be needed to serve replacement supply or demand-side resources that will be added and ancillary services. Retired plants might be replaced by new resources, in which generation may be distant from the load (i.e. wind or other renewables). Detailed transmission system studies may be needed to measure reliability impacts and system reinforcement requirements resulting from specific capacity reductions.

Conclusion

NERC reviewed the impact of either retrofitting units with existing once-through-cooling systems to closed-loop cooling systems (4 percent reduction in nameplate capacity) or unit retirements (capacity factor less than 0.35) on NERC-US and regional capacity margins for 2008-2017. 60 percent of retirements/retrofits were projected to begin in 2013, 20 percent in 2014 and the remaining 20 percent in 2015. This was retirement/retrofit process was consistently performed in each sub-region.

Based on a worst case view, NERC-US Adjusted Potential Resources may be impacted up to 49,000 MW, reducing the Adjusted Potential Resource Margin by 4.3 percent and some areas may require more resources to offset capacity reductions and maintain the reliability of the bulk power system. Some sub-regions experience significant impacts such as California, New England, Texas, South-Central and New York. These regions/subregions may require additional resources to accommodate the potential retirements/retrofits from the Section 316b Phase II action.

Transmission congestion and reliability might be aggravated and detailed system transmission studies may be needed to determine bulk power system reliability resulting from the loss of the specific units studied.

[82] http://nietc.anl.gov/documents/docs/NIETC_MidAtlantic_Area_Corridor_Map.pdf
[83] http://www.oe.energy.gov/nietc.htm