UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by	)	
	)	Docket No. RM10-23-000
Transmission Owning & Operating Public Utilities	)	

SUPPLEMENTAL COMMENTS

1. On behalf of the Sierra Club, the Natural Resources Defense Council, and Citizens for Pennsylvania's Future, Earthjustice offers the following supplemental reply comments on the Notice of Proposed Rulemaking issued by the Federal Energy Regulatory Commission ("FERC") in this proceeding on June 17, 2010 ("NOPR"). *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 75 Fed. Reg. 37,884 (June 30, 2010). As outlined in the reply comments submitted previously, Earthjustice commissioned Synapse Energy Economics ("Synapse") to analyze why integrating public policies into a transparent, regionally coordinated transmission planning process is needed to ensure just and reasonable rates for electricity as prescribed by the Federal Power Act ("Synapse Report").

2. The attached Synapse Report examines two fundamental concerns that illustrate the relationship between just and reasonable rates and incorporating public policies requirements into bulk power system planning efforts. First, the report reviews recent analyses indicating that new federal regulations will spur the retirement of fossil generation facilities and explains why planning must account for an expanding universe of "at-risk" generation in order to avoid excessive costs to ratepayers. In the absence of effective planning requirements, planning authorities identify reliability concerns and the

means to resolve them only after a retirement is announced definitively. At that point, it can take several years to implement needed transmission or non-transmission fixes, and in the meantime, the unit receives reliability payments that ultimately are made by electricity consumers. Even when a cost-of-service agreement is negotiated and a retirement schedule is set, there is no ongoing planning requirement to track changes in the transmission system and ensure that a retirement can go forward on schedule. Thus, although there may be relatively cheap solutions available to ensure electric reliability, planning authorities are not actively identifying and implementing them, and as a result, ratepayers may be forced to make unnecessary reliability payments to retiring facilities for a decade or more.

3. These reliability payments may cover the costs of installing pollution controls even in the common instance when a generator is seeking to retire based on a determination that investment in pollution control is not economic. In other words, generators can take advantage of reliability concerns to shift the cost of uneconomic clean-ups to electricity consumers. Alternatively, retiring generators that are maintained for reliability purposes may be excused from environmental compliance, an even worse outcome for ratepayers who are forced not only to pay excessive costs but also to prolong their exposure to harmful pollution as a consequence. As the U.S. Environmental Protection Agency ("EPA") finalizes new rules that are critically important to protecting human health and the environment, planning authorities must take swift and effective action to ensure that electric reliability does not come at the cost of clean air and water.

4. The report includes several case studies illustrating why the planning reforms proposed in the NOPR are essential to respond to new federal regulatory

mandates that are expected to elicit retirement of 40 to 60 gigawatts of fossil generation. These case studies reveal how the dynamics discussed above are playing out with respect to specific facilities in PJM Interconnection ("PJM") and the New England Independent System Operator ("ISO") regions. Importantly, this analysis illustrates that Order 890's planning directive, even in combination with other forward capacity markets, and other progressive tariff requirements, is not sufficient to prevent excessive costs in connection with generation retirements.

5. In addition to EPA regulations and at-risk generation, the Synapse Report further focuses on the need to consider energy efficiency mandates in power system planning processes. Specifically, the report evaluates the potential for state energy efficiency mandates to reduce peak load demand in turn reducing the need for new generation and transmission infrastructure. As set forth in our previously filed reply comments, the results of this analysis are remarkable. Considering only the effect of existing energy efficiency programs, peak loads in the Midwest ISO will be significantly lower in 2030 than they were in 2010, and the load demand will remain flat in the New England ISO. These results are directly at odds with current load forecasts which assume ever increasing loads through 2030. Thus, as the Synapse Report explains, planning authorities must account for energy efficiency as they forecast demand and seek to identify any capacity shortfalls. Because energy efficiency resources can eliminate perceived capacity "gaps," accounting for efficiency mandates will discourage unnecessary expenditures on new transmission and/or generation that is not needed—much to the benefit of ratepayers.

6. Given the practical consequences of failing to plan effectively, accounting both for fossil generation retirements and offsetting load reductions achieved by energy efficiency programs, the authors of the Synapse Report conclude that planning reforms are needed to yield realistic projections of future transmission needs. Unrealistic projections lead directly to excessive or misplaced investments in new transmission and generation infrastructure, and if transmission and generation investments are poorly targeted, the ensuing costs to consumers are likely to be unjust and unreasonable.

7. In conclusion, the Synapse Report recommends that FERC enhance its proposed reforms in the NOPR by specifying what categories of state and federal mandates must be considered in the system planning process and by requiring the development of specific evaluation criteria. At a minimum, planning authorities should be required to consider federal mandates established by the Clean Air Act, the Clean Water Act, and other environmental statutes, renewable energy mandates, including renewable portfolio standards and tax incentive programs that can increase penetration of renewable resources, energy efficiency and demand response mandates, and carbon reduction mandates.

8. With respect to EPA regulatory mandates and "at-risk" generation, the Synapse Report proposes that each planning authority be required to catalog resources that meet appropriately defined at-risk criteria and file an annual assessment of at-risk generation in its planning footprint as part of its annual system planning report. The report recommends that authorities be required to assess potential reliability issues and identify alternatives to address them on an annual basis. Further, the report suggests that all planning authorities be required to consider the issuance of requests for proposals to

secure timely solutions once a reliability concern is identified. In summary, planning authorities should be required to develop principled strategies to enable retirements on an expeditious schedule, with a primary focus on the imminent retirement of a significant portion of the nation's coal-fired generation fleet.

Respectfully submitted,

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Public Policy Impacts on Transmission Planning

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Table of Contents

Appendices

Executive Summary

This report examines the need to analyze federal and state public policy mandates in planning processes for the bulk power system. The Federal Energy Regulatory Commission (Commission) is proposing to revise Order 890 to require mandatory annual planning that accounts for renewable portfolio standards and other unspecified policy mandates. We consider in detail two additional sets of policy mandates that should figure into planning decisions given their influence on the electric system and the rates paid by electricity consumers.

First, we examine federal regulatory mandates imposed by environmental statutes—specifically regulation of air and water pollution and coal combustion waste from power plants. New rules that the U.S. Environmental Protection Agency ("EPA") is expected to finalize over the next three years will have significant impacts on the existing fleet of fossil-fuel-fired generation, particularly inefficient coal-fired power plants that have yet to install modern pollution controls. Several recent analyses conclude that 40 to 60 gigawatts (GW) of existing generation is likely to retire rather than comply with environmental standards mandated by the Clean Air Act and Clean Water Act. Figure ES-1 below is a summary of recent retirement estimates by industry and financial analysts.

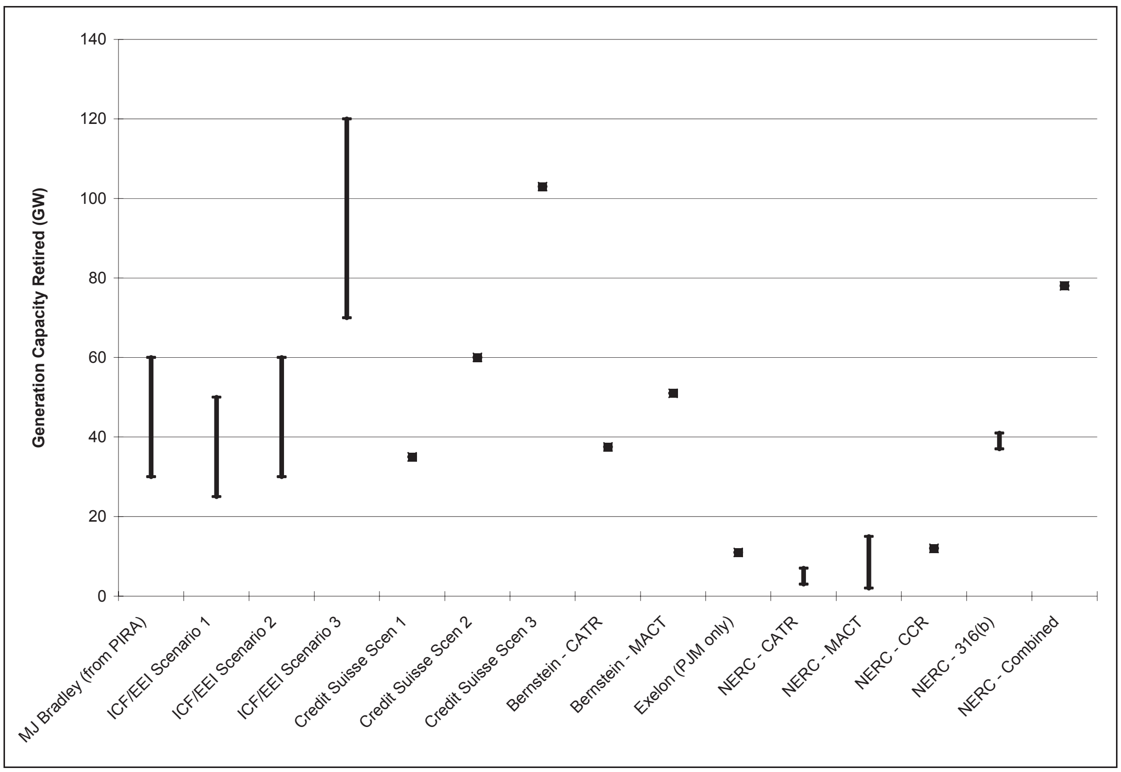

Figure ES-1. Generation Capacity (GW) Retired Due to EPA Rules, by Study and Scenario

Note the general consensus that 40-60 GW of coal retirements are likely over the next half-dozen years. There is also general agreement that uncontrolled and relatively small units of 300 MW or less are most likely to retire. We consider this cross-section of the existing power fleet to be "at-risk" generation. Planning authorities must begin planning now for the retirement of these "at-risk" facilities. Effective planning is essential to identify any reliability concerns raised by retirements and to address them expeditiously to avoid excessive costs to ratepayers. The revised EPA regulations will create a reasonable timeline for compliance and allow planning authorities sufficient time to address concerns provided that the Commission's proposed reforms are finalized soon.

In the absence of such planning, uneconomic units may be retained and paid a special cost of service rate. That rate may include customer-financed investments in costly pollution controls for uneconomic units that otherwise would retire (or in some cases extended periods of non-compliance with health-based environmental standards). We present several case studies in which at-risk generation is not allowed to retire and is instead paid under special reliability agreements that impose excessive costs on electricity consumers. We conclude that annual planning must incorporate analysis of at-risk generation and retirements that federal regulations are likely to elicit in order to avoid this result, which is at odds with the Federal Power Act's fundamental directive to maintain just and reasonable rates.

Second, we consider state policies aimed at reducing energy consumption. The energy efficiency programs that are now in place in many states are sufficient today to stabilize load growth or even reduce load growth over the next ten years. In this way, these programs can offset the impacts of expected retirements. Programs in a majority of states are expressly designed to slow load growth very significantly. We provide an analysis of future load growth in three regional transmission organizations (RTOs)—the Midwest Independent System Operator (MISO), ISO New England, and PJM Interconnection (PJM)— using several different assumptions about implementation rates of energy efficiency programs. Table ES-1 below provides a summary of that analysis.

Table ES-1 Summary of EE Scenarios in 3 RTOs

Scenario	MISO	ISO-NE	PJM
Base Peak Load (MW), 2010	98,963	27,190	129,102
Base Peak Load (MW), 2030	116,165	35,808	176,956
RTO Assumptions, Cumulative EE (MW), 2030	11,233	1,073	679
Load - EE (MW)	104,932	34,735	176,277
Δ (RTO Assumptions Net Peak Load 2030 - Base Peak Load 2030), %	-9.67%	-3.00%	-0.38%
RTO Modified Assumption, Cumulative EE (MW), 2030	19,373	5,187	23,516
Load - EE (MW)	96,792	30,621	153,440
Δ (RTO Modified Assumptions Net Peak Load 2030 – Base Peak Load 2030), %	-16.68%	-14.49%	-13.29%

Scenario	MISO	ISO-NE	PJM
RTO Current Programs, Cumulative EE (MW), 2030	23,392	7,723	30,250
Load - EE (MW)	92,773	28,085	146,706
Δ (RTO Current Programs Net Peak Load 2030 – Base Peak Load 2030), %	-20.14%	-21.57%	-17.09%
RTO Best Practices, Cumulative EE (MW), 2030	29,618	10,075	40,984
Load - EE (MW)	86,547	25,733	135,972
Δ (RTO Best Practices Net Peak Load 2030 - Base Peak Load 2030), %	-25.50%	-28.14%	-23.16%

This table shows that the Current Programs case reduces forecasted peak load by an average of about 20% for all three RTOs. The impact on MISO is to lower its peak load in 2030 below its peak load in 2010. The impact on ISO New England is to maintain peak loads in 2030 at about the same level as they are in 2010. In PJM, the 2030 peak load is still higher than its peak in 2010 but is still reduced by over 17%. We conclude that the failure to account for these significant reductions in load growth during the planning process would create a significant risk of over-building the grid and/or over-investing in new generation, ultimately at the expense of ratepayers.

Other federal and state policies will have similarly profound impacts on the availability and need for generation and transmission resources. Renewable portfolio standards, carbon abatement polices, feed-in tariffs, and direct subsidies all need to be evaluated in the planning process. We provide recommendations at the end of this report on how the Commission can provide appropriate guidance to ensure that planning authorities thoroughly address the impacts of public policies on future bulk power system needs.

We recommend that the Commission's proposed reforms to the planning process be adopted and that additional guidance be provided to ensure that planning authorities can identify cost-effective solutions for bulk power system enhancements and avoid misplaced or unnecessary investments.

1. Overview

On June 17, 2010, the Federal Energy Regulatory Commission (FERC or the Commission) issued a Notice of Proposed Rule Making (NOPR) that focused on transmission planning and cost allocation issues.[1] In this report, we examine the NOPR's proposal to incorporate federal and state public policy requirements into the transmission planning process.[2] This report analyzes the impacts of federal and state public policies on the efforts of planning authorities to maintain a reliable bulk power system that can deliver electricity services at just and reasonable rates pursuant to the Federal Power Act.

Future grid infrastructure needs will be shaped by federal and state policy mandates—new federal regulations governing power plants, state energy efficiency programs and renewable resource portfolio standards, carbon abatement measures, and other policies designed to curb the substantial environmental pollution associated with the electric industry.[3] Incorporating these public policy requirements into planning processes will allow for better decision-making, reduce costs, and avoid unnecessary investments.

Conversely, if planning authorities fail to account for public policy requirements, planning exercises will not yield realistic projections of future transmission needs. Instead, they are likely to yield excessive or misplaced investments in new transmission and generation infrastructure (*e.g.*, unneeded projects, projects that make use of outdated technologies, or projects that would be better implemented in other parts of the bulk power system). If transmission and generation investments are poorly targeted, the ensuing costs to consumers may not meet the just and reasonable rates requirement of the Federal Power Act.

To assess the impacts of public policies on bulk power system planning and maintenance, we examined two sets of issues that demonstrate the relationship between rates and responsible planning.[4] First, we considered the potential for new federal regulations to spur retirements of fossil generation and the corresponding need to account for so-called "at-risk" generation in the planning process. It is important for planning authorities to have effective procedures in place to identify at-risk generation, monitor at-risk facilities, and plan for power system enhancements (new transmission, new generation, new demand resources, or a combination thereof) in the context of annual planning. Good planning will help to target system upgrades most cost-effectively and avoid expensive reliability agreements to retain uneconomic or unlicensed resources. Second, we considered the potential for state energy efficiency mandates to reduce system demand and the corresponding need to account for reduced loads both in developing

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[1] *Transmission Planning and Cost allocation by Transmission Owning and Operating Public Utilities,* RM10-23, 75 Federal Register 37,884 (June 30, 2010).
[2] Id., at ¶ 70.
[3] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 17. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.
[4] While this report focuses on federal regulations and state energy efficiency measures, there are many other public policies that should be incorporated into the transmission planning process. They include renewable portfolio standards, feed-in tariffs for specific resources, regional greenhouse gas initiatives, and investment tax credits for specific resources. Future state or federal actions related to carbon emissions will also be relevant for consideration in transmission planning processes.

load forecasts and in planning new infrastructure to meet projected demand. Because energy efficiency can eliminate perceived capacity "gaps," accounting for efficiency mandates will discourage unnecessary expenditures on new transmission and/or generation that are not actually needed. In this way, the two sets of issues addressed in this report are intertwined. Effective system planning requires accounting for the impacts of federal regulations on retirements and also accounting for state efficiency mandates that can counter-balance these reductions in generation capacity.

We follow our discussion of these issues with case studies that illustrate the practical consequences of failing to plan effectively for likely retirements in response to federal air, water, and waste regulations and for significant reductions in electricity demand in response to energy efficiency mandates.

We conclude the report by providing specific recommendations for enhancements to the Order 890 planning process in response to the Commission's NOPR on reforms to planning and cost allocation. The Commission has the statutory obligation pursuant to the Federal Power Act to ensure that rates are just and reasonable and not unduly discriminatory. The Commission has exercised that authority in Order 890 to impose obligations on planning authorities. The current NOPR recommends further enhancements to existing planning processes, and this report recommends Commission adoption of specific requirements for planning authorities to monitor and evaluate the potential impacts of federal and state public policies. In addition, planning authorities should be required to develop principled strategies to enable retirements of at-risk resources on an expeditious schedule, with a primary focus on the imminent retirement of a significant portion of the nation's coal-fired generation fleet.

Implementing these recommendations would provide planning authorities with additional analytical tools to better assess future bulk power system needs and to avoid uneconomic investments and expensive reliability agreements. The operational requirements for the bulk power system and the resources needed to meet those requirements are evolving at a rapid pace. Federal and state policies, rules, and regulations are contributing to this evolution. In order to effectively respond to this rapidly changing environment, planning authorities need to expand the scope of issues that they review when making recommendations for future system enhancements.

2. Federal Regulation of Power Plants: Planning Must Account for Likely Retirements

Current approaches to retirement planning have led to delays in unit retirements and costly reliability agreements. In some cases, resources have avoided compliance with federal and state regulations (or forced consumers to pay those compliance costs upfront) because of reliability issues that planning authorities have failed to address. Planning authorities must undertake reforms to avoid this result as more power plants contemplate retirement, particularly in response to coming EPA regulations that will force compliance with key pollution control mandates under the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act (RCRA).

The largest quantity of at-risk facilities are fossil-fuel generators that will need to comply with these new, more stringent environmental standards being developed by the Environmental Protection Agency (EPA).[5] We begin with a brief summary of what "at-risk" generation is. We then review the upcoming rule changes, and provide estimates of the compliance costs for some of the new regulations. We also review various estimates of the quantities of coal-fired generation that are likely to retire over the next several years.

In light of these anticipated retirements, we review the available options to account for at-risk generation in the transmission planning process. Planning authorities currently use a variety of methods to assess generation resources that may be at risk of retiring. We examine current approaches and detail failures to avoid the continued operation of uneconomic resources with uplift charges and reliability agreements.

We provide several case studies to illustrate the current capabilities and limitations of existing planning authority processes. This analysis demonstrates that there are two broad concerns related to at-risk generation assessments: the reliability issues associated with plants that want or need to retire and the out-of-market costs that are assessed to consumers when resources are retained for reliability purposes. Planning authorities can impose significant costs on consumers (through reliability cost-of-service agreements) if they determine that specific at-risk facilities need to be retained for reliability purposes.

A. Identifying at-risk generation

Efforts to identify and develop sensitivity analyses to address at-risk generation are increasing across the country. ISO New England addressed several kinds of risks in its annual assessment of the New England grid. The 2010 Regional System Plan discussed risks associated with fuel sources, air regulations, aging plants, environmental compliance, as well as general economics.[6]

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[5] FERC already is aware of the need to consider the role that forthcoming EPA regulations will play in eliciting retirements of older, dirtier generating plants. *FERC Chairman Seeks Review Of EPA Rules Affecting Electricity Reliability,* EnergyWashington.com (Sept. 17, 2010) ("Chairman Jon Wellinghoff is calling for an inter-agency taskforce that would include EPA to examine how upcoming greenhouse gas controls and other air quality requirements could affect the reliability of the electricity grid.").

[6] The annual Regional System Plan is a comprehensive look at the New England bulk power system: the loads, the resources, and the wires that link them together. It is a required study pursuant to ISO New England's FERC-

PJM is devoting a series of stakeholder meetings to vet issues related to at-risk generation in order to improve its annual Regional Transmission Expansion Plan ("RTEP") process.[7] The NOPR reforms and the recommendations we provide at the end of this report will assist the planning authorities that have already begun to address at-risk generation and provide guidance to those who need to start the process.

Identifying resources that have or could have licensing issues is important for cost-effective system planning. Resources that are unable to meet their licensing requirements (due to outdated technology, age, or other reasons) may be subject to restrictions on when they can operate or may be compelled to retire. Planning authorities need to look forward and identify the resources that may become at risk due to licensing and other regulatory issues. Once they identify potential at-risk resources, the planning authorities need to develop plans for system enhancements that can accommodate the reduced operation or retirement of these resources.

Most generation facilities have restrictions on air emissions, water discharges, waste containment and disposal, and specific local operating conditions. Most of these facilities require licenses or periodic demonstrations of compliance with appropriate regulatory authorities. The future EPA regulations mentioned above are a form of licensure for fossil-fueled resources in regard to air, water, and solid waste impacts. Power plants generally have several types of operating permits that must periodically be renewed.

Nuclear plants have operating licenses from the Nuclear Regulatory Commission (NRC). Most first-generation nuclear facilities have reached the end of their initial 40-year operating licenses and have either received renewals or will soon be applying for renewals.

Ultimately, economics are the best indicator of what qualifies as at-risk generation. If anticipated revenues from continued plant operation do not cover future operating costs, maintenance, and investments, then a resource is "at-risk." Some resources are at-risk because they have old structures, they use old technology that is difficult to retrofit, or they are simply less efficient than units with new boilers and turbines. All planning authorities need to develop a screening analysis to identify regional resources that are at risk of retirement based on age, fuel-type, technology, and other relevant factors.

Details about specific plant characteristics can be useful in assessing at-risk generation. For instance, it is important to know whether or not a facility has scrubbers and what other types of pollution controls it has in order to determine whether it will be able to comply with the more stringent emission limits that EPA is expected to finalize over the next two years. It is also important to know what a facility's water consumption needs are and what waste containment procedures (such as those developed to handle coal ash) it employs. Fuel supply itself can create at-risk generation. Due to potential limitations on natural gas supplies during cold winter weather, ISO New England has developed specific programs to encourage dual-fuel capability for gas-fired generation. These limitations occur due to competing demands from space heating and industrial uses of natural gas with power generators who want to produce electricity. Absent the expansion of pipeline capacity to New England or a significant increase in liquefied natural gas

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designated role as the regional system coordinator. The ISO New England Board of Directors approved the 2010 Regional System Plan in October 2010 after a twelve-month stakeholder process.

[7] *Planning Process Timeline*, PJM Regional Planning Process Working Group, October 29, 2010, slide 12.

(LNG) imports, the availability of gas generation resources may be limited during severe winter weather. ISO New England has implemented special notification procedures and special bidding rules that are used whenever weather forecasts and system conditions create potential "cold snap" events. These special provisions try to ensure that owners of gas-fired generation can provide necessary services and receive appropriate compensation for those services.[8] New England's special cold weather rules and operating procedures are a good example of proactive planning that addresses and accommodates a specific class of at-risk generation, in this case natural gas resources operating during cold weather. There is nothing that prevents planning authorities from developing additional specific rules and procedures for other classes of at-risk generation in order to minimize costs and maintain reliability. We provide recommendations at the end of this report on ways that the Commission can require planning authorities to improve their planning processes to address at-risk generation.

B. EPA Regulations

The EPA is in the process of numerous rulemakings, many of them court-ordered, which implement statutory requirements under the Clean Air Act, Clean Water Act and RCRA. Several of these rules will regulate the power sector directly. These include revisions of Clean Air Act new source performance standards for power plants, regulation of interstate pollutant emissions from power plants, regulation of hazardous air pollutant emissions from power plants, haze regulations, new standards governing cooling intake water, and new effluent limitation guidelines for wastewater discharges from power plants. In addition, EPA has proposed to regulate the disposal of coal combustion wastes for the first time. Finally, the EPA is in the process of revising several National Ambient Air Quality Standards ("NAAQS") for pollutants including particulate matter, ozone, sulfur dioxide, and nitrogen oxides. Revised NAAQS will result in the designation of additional nonattainment areas, which in turn will obligate states to require emissions reductions from major pollution sources including power plants.

When considered individually, these rules to varying extents will require retrofits and associated outages and may result in retirements and/or the repowering of existing electric generating units across the United States. Taken together, these rules will have a significant effect on the generating fleet. The following sections describe what are anticipated to be the most economically consequential rules, and summarize the analysis undertaken to date on the costs of these future regulations and associated impacts on the power sector.

i. Clean Air Transport Rule

The Clean Air Transport Rule, proposed in July 2010, will reduce emissions that contribute to non-attainment of National Ambient Air Quality Standards (NAAQS) or that interfere with maintenance of those standards by downwind states.[9] Based on the current proposal, emissions of sulfur dioxide and nitrogen oxide from electric generating units in 31 eastern states and the District of Columbia will be capped to help enable downwind states to comply with the NAAQS,

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[8] ISO New England Market Rule 1, Appendix H: *Operations During Cold Weather Conditions.* Available at: http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

[9] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Federal Register / Vol. 75, No. 147 / Monday, August 2, 2010 / Proposed Rules, pp. 45210 ff.

including the annual PM 2.5 NAAQS (promulgated in 1997) and the 24 hour PM 2.5 NAAQS (promulgated in 2006).[10] Compliance with the transport rule will require substantial investments in scrubbers and other control devices at many generation stations.

The Clean Air Transport Rule sets limits on the emission of sulfur dioxide and nitrogen oxide that will become effective in two phases. Sulfur dioxide emissions are required to decline from 4.7 million tons in 2009 to 3.9 million tons by 2012, and then to 2.5 million tons by 2014, for a cumulative reduction of 47% over the five-year compliance period. The rule is likely to have a minimal effect on nitrogen oxide emissions, however, because the rule's emission caps (1.4 million tons per year) are slightly higher than the actual nitrogen oxide emissions in the covered states in 2009.

In the July 2010 proposal, the EPA identified a preferred approach, but also took comments on two alternatives. All three approaches would cover the same geographic area, set a pollution limit (or budget) for each state, and obtain the mandated reductions from power plants. The EPA's preferred approach and the first alternative would both allow trading of emissions allowances among power plants within a state, with the preferred approach also allowing some limited trading among states. The third approach would allow averaging among a power plant owner's in-state generating units.[11]

To achieve the required emissions reductions, the EPA expects that power plants will "fuel switch" to lower sulfur coal, operate already installed emissions control equipment more frequently, or install new pollution control equipment.[12] The EPA anticipates that a final rule will be issued in the spring of 2011.

The EPA estimates that the costs of compliance with the Clean Air Transport Rule are $2.8 billion in 2014. The EPA's estimate of the expected benefits from the proposed rule range between $120 and $290 billion in 2014. The EPA expects that electricity prices will increase by less than 2%, natural gas prices will increase by less than 1%, and coal use will be reduced by less than 1%.[13]

The EPA has begun assessing the transport of air pollution across state boundaries that would interfere with attainment of the 2010 ozone standard. The Second Clean Air Transport Rule will address the responsibility of upwind states to downwind state ozone problems under the Clean Air Act. The EPA is expected to propose the Second Clean Air Transport Rule in summer 2011, and promulgate a final rule in summer 2012.[14]

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[10] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 4. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf.

[11] US EPA. *Proposed Transport Rule Would Reduce Interstate Transport of Ozone and Fine Particle Pollution*. Clean Air Transport Rule Fact Sheet. July 6, 2010. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf

[12] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 10. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf

[13] US EPA, Office of Air and Radiation. *Proposed Air Pollution Transport Rule*. July 26, 2010. Slide 13. Available at: http://www.epa.gov/airtransport/pdfs/FactsheetTR7-6-10.pdf

[14] *Id.* Slide 14.

ii. Air Toxics Standards

The EPA is under court order to set emission limits for hazardous air pollutant emissions from electric generating units under section 112(d) of the Clean Air Act. More than 180 hazardous air pollutants are listed under the Clean Air Act, and those most relevant to the electric power industry include mercury, dioxins, and acid gases. This rule would require that sources meet emission limits based on EPA's assessment of "Maximum Achievable Control Technology" or "MACT." For existing sources, this means that the level of control achieved must be in line with the average of the top twelve percent of top-performing power plants. Requirements for new sources are at least as stringent as the single best performing source, reflecting the maximum emissions reductions achievable with state-of-the-art pollution controls. Existing units will have three years to comply with the final rule once it is issued, while new sources will have to comply immediately upon issuance of the rule.[15] The EPA is expected to issue the new proposed rule in March 2011 and finalize the rule in November 2011.[16]

The EPA has not yet released an analysis of costs and benefits of the Maximum Achievable Control Technology rule. However, as discussed below, several recent analyses assess their impact on the power sector.

iii. Coal Combustion Residuals

Coal combustion residuals are byproducts from the combustion of coal that include fly ash, bottom ash, boiler slag, and flue gas materials. In 2008, annual production of these residuals was 136 million tons.[17] The spill of coal ash at the Tennessee Valley Authority's containment facility prompted the EPA in June 2010 to propose two approaches to regulating the disposal of coal combustion residuals under RCRA. The EPA's long-term objective is to phase out the wet handling of coal ash and the use of surface impoundments (ash ponds) in favor of dry ash handling and disposal in lined landfills. Approximately one-third of the coal capacity in the United States uses wet ash handling and storage systems.[18]

The first proposal would regulate coal ash under subtitle C of RCRA and would create a program imposing federally enforceable requirements for waste management and disposal, including the phase-out of wet handling and existing surface impoundments. If EPA pursues the implementation of a coal ash rule under subtitle C, states would be required to adopt the new federal requirements.[19]

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[15] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 17. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

[16] US EPA, Office of Air and Radiation. *Reducing Air Pollution from Power Plants*. September 24, 2010. Slide 7. Available at: http://www.naruc.org/Domestic/EPA-Rulemaking/Docs/EPA%20AIR%20Presentation%20Sept%2024%202010%20_%20Sam%20Napolitano.pdf.

[17] Bryson, Joe. US EPA, Office of Air and Radiation. *Key EPA Power Sector Rulemakings*. Eastern Interconnection States' Planning Council. August 26, 2010. Slide 19. Available at: http://communities.nrri.org/c/document_library/get_file?folderId=107847&name=DLFE-3419.pdf.

[18] Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.

[19] US EPA. *Coal Combustion Residuals – Key Differences Between Subtitle C and Subtitle D Options*. Available at: http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/ccr-table.htm.

The second proposal would regulate coal ash under subtitle D of RCRA, and would apply to coal combustion residuals that are disposed of in landfills or surface impoundments. Under subtitle D, the federal government sets national criteria that are used by the states to issue waste management permits, but states are not required to adopt the federal standards. Utilities would likely continue operating surface impoundments, but states and citizens could seek to enforce new federal requirements through citizen suits in the event of environmental damage.

The Edison Electric Institute (EEI) estimates that the costs to convert bottom ash handling systems to dry ash handling systems are $20 million per unit, while costs to convert fly ash handling systems are $10-$15 million per unit.[20] Costs of new landfills for dry ash are between $30 and $50 million.[21]

A date for release of the final coal combustion residuals rule has yet to be determined. If the subtitle C proposal were adopted, implementation would depend on the timing of the approvals from each of the states, which is expected to take at least two years. A subtitle D rule would become effective six months after promulgation of the rule for most of the provisions, but specific provisions would have a longer effective date.[22]

iv. Clean Water Act § 316(b)

Thermal power plants using water for cooling purposes use one of three types of cooling systems: once-through, recirculating, and dry cooling. Once-through systems withdraw water in large volumes and then discharge it back into the same water body at elevated temperatures. Recirculating systems withdraw water in smaller volumes, and continuously circulate the cooling water through a plant's heat exchangers with the aid of cooling towers. Dry cooling systems are closed-loop systems that do not rely on cooling water, but instead on forced draft air flow.

Section 316(b) of the Clean Water Act requires that new power plants use the best available cooling water intake technologies for minimizing adverse environmental impacts. Adverse environmental impacts include the intake of aquatic organisms with cooling water when using once-through systems.

The EPA promulgated a 316(b) rule in 2004 that covered large existing power plants with water intake in excess of 50 million gallons per day. In 2007, the Second Circuit Court of Appeals remanded this rule to the EPA. Absent federal regulations, states have begun to consider and adopt rules governing the retrofit of existing power plants with closed-loop cooling systems. On March 10, 2010, New York's Department of Environmental Conservation proposed a policy that would set a closed-cycle cooling performance goal at all of the state's power plants.[23] The California State Water Resources Control Board issued regulations on May 4, 2010 that would require many steam generators to replace once-through systems with closed-loop systems,

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[20] Edison Electric Institute estimates taken from: Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 66.
[21] *Id*.
[22] US EPA. *Coal Combustion Residuals – Key Differences Between Subtitle C and Subtitle D Options*. Available at: http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/ccr-table.htm.
[23] New York State Department of Environmental Conservation. *CP-nn/Best Technology Available (BTA) for Cooling Water Intake Structures.* March 10, 2010. Available at: http://www.dec.ny.gov/docs/fish_marine_pdf/drbtapolicy1.pdf.

reducing cooling water intake by 93%.[24] EPA is developing revised national regulatory standards implementing Section 316(b) for existing power plants and manufacturing facilities, and plans to publish a Notice of Proposed Rulemaking in March 2011. The EPA already has taken comments on an Information Collection Request.[25]

If the EPA were to promulgate a new rule that applies to a similar set of large electric generators (with intake of more than 50 million gallons per day), many generating units across the United States would need to upgrade existing once-through cooling systems, and in some cases retrofit plants to use closed-loop systems.[26]

C. Assessments of EPA regulations

Several organizations have developed estimates of the impacts of these forthcoming EPA regulations on the existing fleet of electric generating units. Most of these evaluations have focused on resources fueled with coal. We reviewed the assessments of six entities and the assumptions that supported their analyses. We describe each of the assessments below and then summarize the associated emissions control retrofit costs in Figure 1. Although the majority of the assessments examine only the impacts of the Clean Air Transport Rule and Maximum Achievable Control Technology Rule, two of the assessments (ICF Consulting and the North American Electric Reliability Corporation), estimate the impacts from all four of these forthcoming EPA regulations.

i. North American Electric Reliability Corporation (October 2010)

The North American Electric Reliability Corporation (NERC) examines the impact on reliability and planning reserve margins of all four of the forthcoming EPA rules discussed above. Two separate scenarios are used for each of the proposed rules, a moderate and a strict case, and the amount of capacity reductions are calculated based on: 1) accelerated unit retirements, and 2) increased station loads needed to power new environmental control technologies. Units were retired in the NERC assessment if the replacement cost of a unit is less than the cost of operating the unit with installed environmental controls.[27]

Considered individually, the Clean Air Transport Rule is expected to have the least impact on electric power generators of the four rules discussed above, and may result in the retirement of 12 coal units, or 388 MW of capacity. Higher compliance costs could result in additional

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[24] California State Water Resources Control Board. *Statewide Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling*. May 4, 2010. Available at: http://www.swrcb.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf.

[25] US EPA. *Fact Sheet: Proposed Information Collection Request for a General Population Survey to Allow the Estimation of Benefits for the Clean Water Act Section 316(b) Cooling Water Intake Structures Rulemaking.* July 2010. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/316factsheet2010.pdf.

[26] There are 651 generating units with water intake above 50 million gallons per day. Of these 651 generators, there are 404 that are not currently equipped with closed-loop cooling systems.
Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 72.

[27] North American Electric Reliability Corporation (NERC). *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential US Environmental Regulations*. October 2010. Pages I-II. Available at: http://www.nerc.com/files/EPA_Scenario_Final.pdf

retirements. The rule may result in retirements of 3-7 GW and retrofits of between 28 and 576 power plants with emission controls by 2015.[28]

The air toxics rule could result in retirements of 2-15 GW and environmental retrofits for 277 to 753 units by 2015. Planning reserve margins would be affected in eight different NERC regions and sub regions.[29]

A rule under Section 316(b) of the Clean Water Act is projected to have the greatest impact on existing generating units. The rule would apply to 1,201 units, or 252 GW of coal, oil, and gas generating units and 60 GW of nuclear generating units, and may result in retirements of 37 to 41 MW by 2015. Planning reserve margins in half of the NERC regions and sub regions would drop below the Reference Margin Level.[30] Combined, these rules could result in unit retirements of up to 78 GW. Retirements would occur by 2018 in the moderate scenario, and by 2015 in the strict scenario. These estimates further demonstrate why planning authorities need to actively anticipate how the bulk power system will perform and where new infrastructure is needed.

ii. ICF Consulting (May 2010)

ICF Consulting presented results from three modeling scenarios performed by the Edison Electric Institute in May, 2010. The first scenario looks at both the Clean Air Transport Rule and the air toxics rule and assumes that all coal units are required to have selective catalytic reduction, flue gas desulphurization, activated carbon injection and a fabric filter by 2015 and that conversion from wet to dry ash handling is required. Scenario 2 examines the first three rules and Clean Water Act 316(b) rules, adding the assumption that units with intake above 50 million gallons per day are retrofitted with closed-loop cooling and cooling towers. Scenario 3 examines the same four rules as Scenario 2, but also includes a “carbon adder” to represent the regulation of carbon dioxide.[31]

The Edison Electric Institute analyzed gas price sensitivity cases for each of the three scenarios, resulting in a range of possible retirement outcomes for each scenario. Under Scenario 1, 25-50 GW of coal capacity is projected to be retired by 2015. Emissions control retrofits under Scenario 1 would include the following: 100 GW installing flue gas desulphurization; 150 GW installing selective catalytic reduction; and more than 250 GW installing activated carbon injection.[32] Under Scenario 2 between 30 and 60 GW of capacity is projected to be retired by 2015. Emissions control retrofits would include: 90 GW installing flue gas desulphurization; 130 GW installing selective catalytic reduction; and more than 240 GW installing activated carbon injection. Retirements in Scenario 3 are estimated to be between 70 and 120 GW, and resulting emission control retrofits include 70 GW of flue gas desulphurization, 100 GW of selective catalytic reduction, and 200 GW of activated carbon injection.[33]

[28] *Id.* Page V.
[29] *Id.*
[30] *Id.* Page IV.
[31] ICF International. *EEI Preliminary Reference Case and Scenario Results*. May 21, 2010. Slide 5.
[32] Note that generators may install more than one pollution control technology, and capacity is reported separately for each control.
[33] *Id*. Slides 21 and 28.

iii. MJ Bradley (August 2010)

A study done by MJ Bradley & Associates and the Analysis Group expects that although some of the less efficient coal plants in the United States will be retired as a result of the Clean Air Transport Rule and the air toxics rule, many plants will be retrofitted with the necessary emissions controls. Approximately 150 GW of generating capacity is already equipped with flue gas desulphurization technology, 55 GW plan to install this technology, and some generators have already announced plans to retire, leaving 75 GW to switch to lower sulfur coal, install emissions controls, or retire.[34]

Of those 75 GW, the report projects that 30 to 40 GW will retire,[35] but the electric sector is expected to have surplus generating capacity of 100 GW in 2013, leaving capacity levels in excess of minimum reserve margin requirements.[36] Regional reliability also is assured due to capacity markets and reserve sharing mechanisms in many wholesale markets that allow electric generators to access other companies' available resources.[37]

iv. Credit Suisse (September 2010)

An analysis from investment bank Credit Suisse, released in September 2010, examines the combined effects of the Clean Air Transport Rule and the air toxics rule. Credit Suisse first classified the US coal fleet, determining that of the 340 GW of coal generation:

- 103 GW lack major emission controls (30%),
- 65 GW have flue gas desulphurization but not selective catalytic reduction (19%),
- 58 GW have selective catalytic reduction but not flue gas desulphurization (17%), and
- 115 GW have all basic pollution control equipment installed (34%).[38]

Credit Suisse assumes that the lack of flue gas desulphurization makes a plant more vulnerable to retirement or upgrades, as it is the most effective tool to control mercury emissions as required by expected air toxic rule standards. The analysts then used three discrete scenarios to run an economic dispatch model to determine the effects of these EPA rules. In the baseline scenario, Credit Suisse estimates that 60 GW of coal generation are closed. Making up those 60 GW are all of the small coal plants (less than 300 MW of capacity) that do not currently have environmental controls, and half of the small plants that have selective catalytic reduction but do not have a scrubber.[39] Small plants are more vulnerable to retirements because costs of

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[34] PIRA Energy Group. *EPA's Upcoming MACT; Strict, Non-Hg Can Have Far-Reaching Market Impacts.* April 8, 2010. As cited in: MJ Bradley and Associates, LLC and Analysis Group. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*. August 2010. Page 1. Available at: http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf.
[35] *Id.* Page 8.
[36] MJ Bradley and Associates, LLC and Analysis Group. *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability*. August 2010. Page 8. Available at: http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf.
[37] *Id.* Page 4.
[38] Credit Suisse. *Growth from Subtraction: Impact of EPA Rules on Power Markets*. September 23, 2010. Page 6. Available at: http://epw.senate.gov/public/index.cfm?FuseAction=Files.View&FileStore_id=b42de70d-b814-4410-831d-34b180846a19.
[39] *Id.* Page 12.

environmental retrofits on a per-kW basis are higher for smaller units due to economies of scale in the design and construction and emissions control technologies. Those higher investment costs are more difficult to justify due to the fact that many of these plants were placed into service more than 40 years ago.[40] Under the baseline scenario, another 100 GW of coal generation (both small and large) will require pollution control retrofits at significant cost in order to meet EPA emissions rules.[41]

The Midwest Independent Transmission System Operator (MISO) is projected to see the most plant retirements and retrofits in absolute terms, as the regional transmission organization has 32 GW of coal capacity that is lacking pollution control equipment. PJM and the Southeast Electric Reliability Council (SERC) both have approximately 20 GW of uncontrolled coal capacity.[42]

v. Bernstein Research (October 2010)

A report from Bernstein Research examines the effects of the Clean Air Transport Rule and the air toxics rule separately. The firm uses the same methodology to examine both rules, identifying those coal-fired power plants that currently lack flue gas desulphurization technology, and determining where emissions retrofits are economic and where they are not. Bernstein examines forward prices for energy and capacity, forward coal prices, and unit heat rates to determine the present value of each unit's after-tax operating cash flows, and compares these values to the costs of installing flue gas desulphurization technology, net of tax benefits and depreciation expenses. If the present value of future operating cash flow exceeds the cost of installing flue gas desulphurization, emission control technologies are added to the unit in question. If it does not, flue gas desulphurization is not installed and plants may elect to retire.[43]

Bernstein uses the Electric Power Research Institute's estimates of the cost to install flue gas desulphurization technologies. Installation costs on a per-kW basis rise as the size of the unit declines. Flue gas desulphurization for a 500 MW plant, for example, is estimated at $420 per kW, but would cost $607 per kW for a 200 MW plant. Estimates for nitrogen oxide controls are slightly lower but follow the same increasing path as units get smaller, costing $116 per kW for a 500 MW plant and $156 per kW for a 200 MW plant.[44]

Because the Clean Air Transport Rule sets an emissions budget for states as a whole, if the installation of economic flue gas desulphurization controls leads to achievement of the requisite emission cuts in a certain state, then uncontrolled coal pants that are not economic to retrofit will remain in service. Bernstein estimates that in 2009 the domestic coal fleet generated 1.885 billion MWh of electricity, 62% of which was generated by units that have flue gas desulphurization or have announced plans to install this technology, and 38% of which was generated by units that lack this technology.[45] In order to achieve mandated reductions, Bernstein determined that flue

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[40] *Id.* Page 7
[41] *Id. Page 6.*
[42] *Id.* Page 21.
[43] Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 7.
[44] *Id*. Page 22.
[45] These percentage estimates differ from those percentages calculated by Credit Suisse, as the Bernstein values are based on electricity generated (MWh) while the Credit Suisse values were given in terms of generating capacity (GW) and do not consider unit capacity factors and output.

gas desulphurization technologies would be installed at units producing 211 million MWh of electricity (11% of coal generation) and that unscrubbed units producing 147 million MWh of electricity (8% of coal generation) would be retired.[46] According to Bernstein, regulatory status of power plants will be critical in determining whether plants install pollution control technologies or are forced to retire.[47] For those regulated utilities, costs for emissions retrofits are recoverable costs and may be added to regulated rate base, while unregulated or merchant generators are unable to recover any environmental capital expenditures.[48]

Bernstein expects that the air toxics rule will require flue gas desulphurization, along with additional emission controls, on all coal-fired units by 2015. For each individual unit, if the costs of flue gas desulphurization retrofits are higher than the present value of cash flows, those units are forced to retire no later than 2015. The analysis demonstrates that unscrubbed coal units generating 275 million MWh of electricity (15% of coal generation) will be forced to retire and that the remaining unscrubbed units, generating 439 million MWh of electricity (23% of coal generation), will undergo pollution control retrofits.[49] Bernstein concludes that the rule will force the retirement of many smaller, older coal units "whose low profitability and short remaining useful lives render the required environmental upgrades uneconomic. The scale of these retirements will have a material impact on the markets for energy and capacity, as well as those for coal and natural gas."[50]

The Southeast and Midwest are likely to experience the largest decreases in coal generation, particularly affecting the Southeast Reliability Corporation, Southwest Power Pool, Midwest Reliability Organization, and Reliability First Corporation reliability areas. Bernstein states that plant retirements in these areas could lead to a decline in regional capacity margins of 5-11%, to 8% in the Southeast Reliability Corporation, 8% in the Southwest Power Pool, 10% in the Midwest Reliability Organization, and 12% in the Reliability First Corporation. The firm expects that many of these plants with the potential to retire will become subject to reliability-must-run (RMR) agreements in order to ensure that their generating capacity continues to be available to the electric grid.[51]

vi. Exelon (November 2010)

Exelon presented an analysis of the Clean Air Transport Rule and the air toxics rule specific to PJM at the Edison Electric Institute Financial Conference in November 2010. Of the 75 GW of total coal capacity in PJM, Exelon determined that it would be economically rational to retire 11 GW of coal capacity by 2015. These 11 GW are made up of power plants less than 300 MW in

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[46] Bernstein Research. *U.S. Utilities: Coal-Fired Generation Is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* October 2010. Page 15.
[47] *Id.* Page 24.
[48] *Id.*
[49] *Id*. Page 27.
[50] *Id*. Page 1.
[51] Bernstein Research. *Black Days Ahead for Coal: Implications of EPA Air Emissions Regulations for the Energy & Power Markets*. July 21, 2010. Slide 11. Available at: http://grist.s3.amazonaws.com/eparegs/Bernstein%20-%20black%20days%20ahead%20for%20coal%20-%2007%2021%2010.pdf.

size that lack all environmental controls.[52] Exelon expects that energy prices will rise $5-$7 per MWh due to coal retirements and environmental retrofits. "While results are largely dependent on bidding behavior, Exelon expects increasing capacity prices beginning in the 2014-15 planning year as coal generators evaluate environmental compliance costs."[53]

D. Compliance Costs and Retirements Summary

Costs to comply with EPA's forthcoming rules vary between the different analyses, and also vary according to unit size within analyses. Estimates of the number of gigawatts of generation capacity that retires due to forthcoming EPA rules also vary between analyses. Figure 1 presents the range of estimated compliance costs for the various pollution control technologies presented in the studies discussed above. Figure 2 shows the different estimates of generating capacity that will be retired by 2015 under the various scenarios.

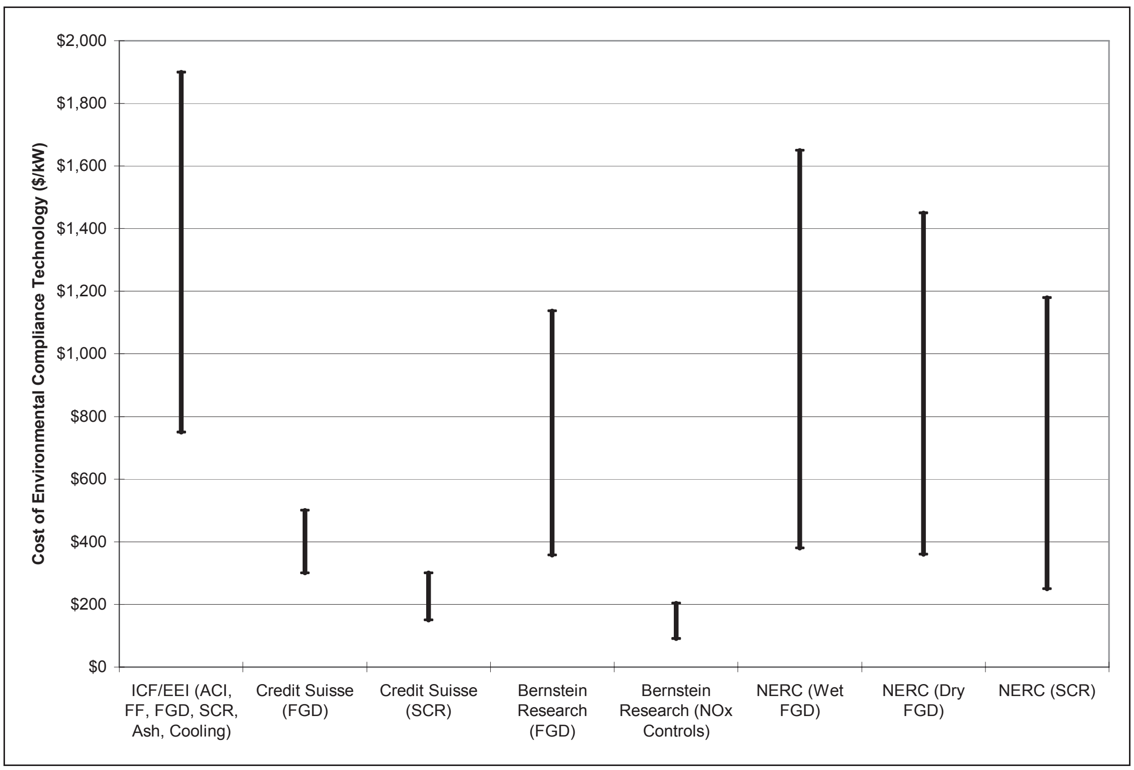

Figure 1. Estimates of Environmental Compliance Costs by Entity and Technology

These estimates of compliance costs raise an important issue for the planning process. In many regions of the United States there is a surplus of generating capacity today. State policies to reduce carbon impacts such as the Regional Greenhouse Gas Initiative and Renewable Portfolio

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[52] Crane, Chris. *Clean in Competitive Markets*. Exelon. Presentation at the Edison Electric Institute Financial Conference. November 1-2, 2010. Slide 4. Available at: http://www.eei.org/meetings/Meeting%20Documents/2010NovFin-Exelon.pdf.

[53] *Id*. Slide 6.

Standards may drive the development of new, clean generation resources that receive substantial financial support outside of the electricity markets (through renewable energy credits or more direct subsidies such as tax credits and feed-in tariffs).

The compliance costs that will be incurred by many generating units will require them to seek additional market revenues from higher energy bids or capacity bids or both. In a wholesale market place with existing surpluses of resources and competition from new resources that may have financial assistance outside of the wholesale markets, retrofitted resources may not be able to recover their compliance costs. This dynamic will either increase the quantity (GW) of resources seeking to retire because they are no longer competitive. If planning authorities do not account for these retirements in their planning process, then these uneconomic resources may be retained for reliability purposes for many years.[54]

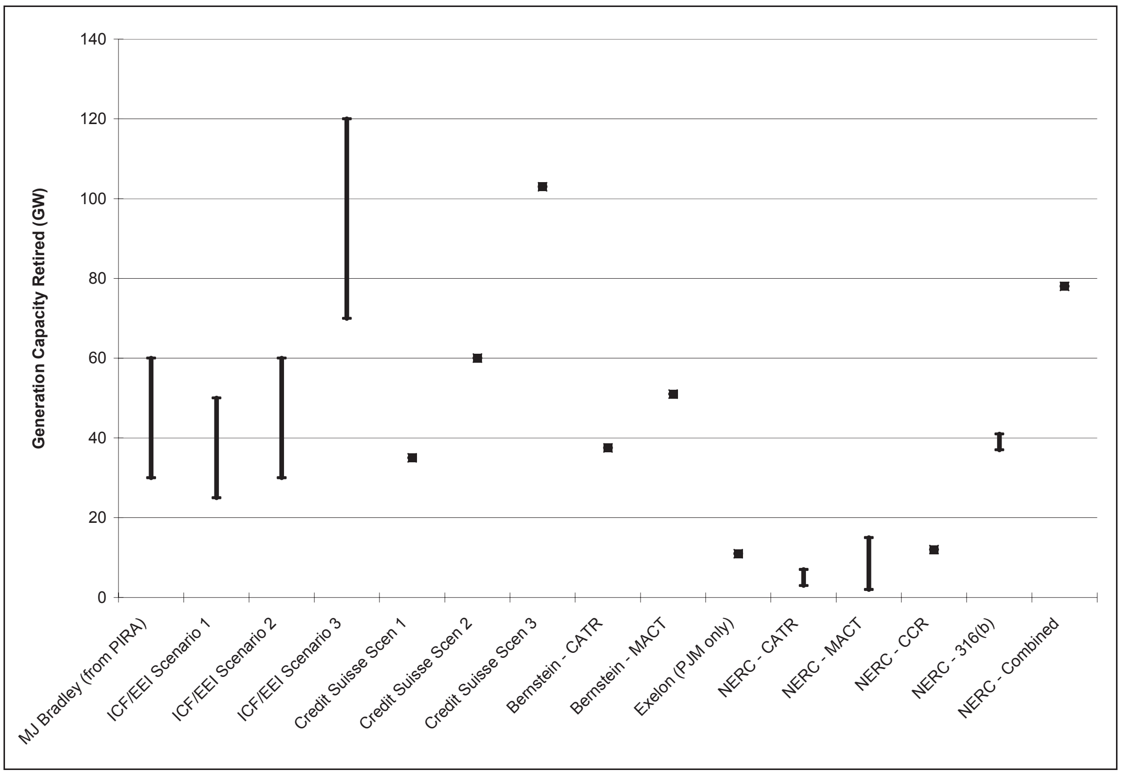

Figure 2. Generation Capacity (GW) Retired Due to EPA Rules, by Study and Scenario

Figure 2 shows that there is consensus among the various estimates that ~60 GW of coal plants will retire pursuant to new EPA regulations. This represents about 17% of the current fleet of coal units (~340 GW) and is consistent with the Exelon estimates of PJM fleet retirements of 14.6% (11 GW out of a total of 75 GW).

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[54] We provide examples of units retained for reliability and estimate some of the excess costs associated with those units in the case studies that follow.

E. Reliability Impacts of at-Risk Generation

While even the most dramatic retirement projections leave the vast majority of existing generating capacity in place, individual retirements are likely to raise at least some localized reliability concerns relating to grid stability, voltage support, reserve margins, and contingency support. Retirements have the potential to contribute to annual resource adequacy deficiencies and long-term planning uncertainties.

i. Resource Adequacy and Operational Reliability

The regional bulk power systems were developed over the years by connecting loads that consume energy to resources that provide energy through a dynamic system of wires and equipment that were designed to meet a specified reliability standard. The geographic locations of loads and generating resources were critical to the development and evolution of integrated power systems.

It is no surprise, therefore, that specific generation resources often provide multiple benefits to the overall reliability of the system due to their geographic proximity to loads, other resources, and existing transmission infrastructure. Although age and size may be indicators that retirement is appropriate and necessary, it requires a case by case analysis to document the role that each resource plays in the overall system. In some cases, retirement of even small resources can have relatively significant impacts.

Resource adequacy determinations can identify specific resources that on a local or system-wide basis are needed for overall system reliability. The standard metric for resource adequacy analysis is no system-wide loss of load events more frequently than "one day in ten years".[55] Planning authorities prepare resource adequacy analyses as a first cut analysis of system reliability. If a region does not have sufficient resources to meet its system wide coincident peak day loads under the "one day in ten years" standard, then remedial steps may be warranted. This can include retaining generation that requests retirement and issuing specific requests for proposals to implement interim and/or permanent solutions.

Operational reliability determinations are made on a day to day or multi-day basis depending on the specific resources available to the planning authority, transmission line availability, and estimated loads. The need to operate generation units out-of-merit in order to meet a reliability need such as stability, voltage support, or energy demand produces uplift charges that are assigned to customers in the zone or region that is experiencing the reliability violation. Uplift charges may occur on an infrequent or frequent basis depending on the specific reliability concern that is being addressed. To a large extent, these are uncontrolled and unhedged costs that eventually flow back to consumers. Uplift costs may be relatively temporary until a new resource or transmission line is in service, or they may continue for a daily basis for several years while a permanent solution is (or is not) developed.[56]

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[55] This is also described as a Loss of Load Expectation (LOLE) of one day in ten years.
[56] Connecticut experience several years of high uplift costs during the last decade until a major new transmission line was completed. The Northeast Massachusetts (NEMA) zone experienced more sporadic uplift charges during that same time period while a 345 kV line was built to provide more imports to the Boston area.

We do not evaluate the numerous reasons for uplift costs or estimate the current and future dollar impacts of uplift from at-risk generation. Such an analysis would require a detailed review on a case by case basis and is beyond the scope of this report. Nonetheless, planning authorities should include an analysis of uplift costs associated with at-risk generation within their footprint.

ii. Out-of-market contracts

When resources are no longer economic to operate, owners will usually seek to retire the resource from service. Prior to approving a retirement request, a planning authority must determine whether the permanent unavailability of the resource will compromise system reliability. That determination can sometimes be made quickly but will usually require a detailed transmission system analysis.

If the planning authority determines that the resource is needed for reliability, even if that reliability need is only for extreme weather conditions or for a few hours each year, the resource can request a cost of service contract. The cost of service contract allows the resource to recover its annual FERC-approved costs regardless of how often, if at all, it actually operates and produces energy. These contracts are also called reliability-must-run (RMR) contracts.

From a planning perspective, the important issues raised by resource retirements are three. First, can the system be operated to reliability standards if the resource retires? If the answer is “no”, then a planning authority needs to address a second issue: what changes to the bulk power system are needed to accommodate the retirement and what is the timeframe in which the changes can be implemented? Finally, the planning authority must determine how long to retain an uneconomic resource that wants to retire while it implements the necessary enhancements to allow the retirement. The length of time that an uneconomic resource is retained or the length of time to implement a system upgrade will have a big impact on the excess costs that customers pay through uplift or reliability contracts. The sooner that a planning authority begins its assessment of at-risk generation and identifies solutions, the less exposure consumers will have to excessive costs and unjust rates.

F. Case Studies of At-Risk Generation

The following examples illustrate the dynamics discussed above and underscore the importance of responsible planning in combination with tariff requirements that compel timely action to allow for retirements and avoid reliability payments.

i. Vermont Yankee

This case examines how a nuclear power plant can impose excess costs on electric consumers through the Forward Capacity Market (FCM) in New England. The system planning process in New England is one of the more progressive ones in the country, and it also benefits from a forward capacity market. Nonetheless, the Vermont Yankee case shows the limitations of this process and the need for the Commission to provide additional guidance through the adoption of specific planning criteria in the NOPR.

Vermont Yankee is a 650 MW nuclear power plant that began operation in 1970. It has an operating license through March of 2012. Entergy owns Vermont Yankee and is currently seeking a twenty-year license extension through 2032.

Vermont Yankee is an existing capacity resource in New England and has participated in the first four capacity auctions that began in 2007. In the first three forward capacity auctions, Vermont Yankee offered and cleared approximately 604 MW.[57]

In the fourth forward capacity auction completed this August, Vermont Yankee entered a de-list bid. A de-list bid acts as a minimum price offer. If the auction price goes below the minimum bid, then that resource is not included as a cleared resource, and it does not have a capacity supply obligation for the relevant power year. Vermont Yankee's de-list bid was for $3.933/kW-month.

The fourth forward capacity auction was for the 2013-14 power delivery year.[58] The clearing price was $2.95/kW-month and the pro-rated MW price (due to oversupply at the clearing price floor) was $2.52/kW-month. Under normal auction procedures, the Vermont Yankee de-list bid would have been accepted. Prior to accepting any de-list bid, however, ISO New England conducts a reliability review to see if the absence of the resource would cause significant reliability concerns. When ISO New England reviewed Vermont Yankee's de-list bid during the auction, it rejected the bid due to reliability concerns.

Once a de-list bid is rejected, the resource remains as a cleared resource for that forward capacity auction delivery year, but its payments are not limited to the auction clearing price. Depending on the type of de-list bid, the resource may be paid its de-list offer or a payment based on a cost-of-service calculation. If accepted by the FERC, the Vermont Yankee payment for the 2013-14 delivery year will be its dynamic de-list bid of $3.933 kW-month.

As shown in Table 1 below, the difference between Vermont Yankee's de-list bid of $3.933 and the pro-rated auction clearing price of $2.52 results in additional revenue to Vermont Yankee of over $10 million for the 2013-14 delivery year. The $10 million additional payment to Vermont Yankee is a cost that New England consumers could have avoided if other, lower-priced resources had cleared the fourth forward capacity auction instead of Vermont Yankee.

[57] Forward capacity auctions (FCAs) are held approximately three years in advance of the delivery year. In each FCA, capacity is purchased to meet the installed capacity requirement (ICR) for the delivery year. The installed capacity requirement is the total MW needed to meet peak load, reserves, and any specific operational needs to maintain a reliable system.

[58] June 1, 2013 through May 31, 2014. It is unclear how Vermont Yankee will meet its FCA-3 obligation that begins June 1, 2012, if it does not get a license renewal in March of that year. The FCM rules allow for a resource to transfer its CSO to another resource through a bilateral contract.

Table 1. Vermont Yankee Participation in FCA

Vermont Yankee	FCA 3	FCA 4
Unit Capacity, MW	604	604
Pro-rated clearing price, $/kW-month	-	2.52
De-list bid price as accepted by FERC, $/MW	-	3.933
Annual cost over market rate, $ mln	-	10.24

This example illustrates how a delay in identifying a unit that may need to retire can lead to excessive costs to consumers. Under its current planning procedures, ISO-New England is just starting its detailed evaluation of the need for the Vermont Yankee facility and the potential replacement alternatives.[59]

A more robust planning process that identifies at-risk generation based on objective criteria would provide a longer lead time to develop and implement solutions. Excessive costs to ratepayers could be avoided while reliability is maintained. The current approach of waiting for the resource owner to declare his unit at-risk (through a de-list bid) does not provide adequate time, even with a three-year forward capacity market, for a planning authority to develop and implement solutions.

ii. Salem Harbor

Salem Harbor provides another example of how, despite a progressive and well-developed system planning process, resources can be retained for many years past their cost-effective retirement date. In addition, transmission upgrades were implemented to allow Salem Harbor to retire but proved to be ineffective when other retirements on the system occurred. A more robust tracking of at-risk, uneconomic generation resources may well have produced a better outcome for electric consumers while maintaining reliability standards.

Salem Harbor is the site of four separate generation units: an oil facility (430 MW) and three coal facilities (two 80 MW and one 150 MW). The coal units are all 50 years old or older; the oil unit is 37 years old.

[59] It is worth noting that in the Salem Harbor example discussed next, the ISO has asserted that its obligation to seek a replacement for a resource that has its de-list bid denied is only triggered once that resource submits a permanent de-list offer in an FCM auction (in contrast to dynamic de-list offer or a static de-list offer).

Table 2. Salem Harbor Units 1 and 2

Resource Name	Summer Qualified Capacity (MW)	Commercial Operation Year	Age (years)
SALEM HARBOR 1	81.988	1952	57
SALEM HARBOR 2	80.000	1952	57
SALEM HARBOR 3	149.805	1958	51
SALEM HARBOR 4	431.000	1972	37

For the third forward capacity auction, static de-list bids were submitted for all four units. ISO New England conducted a reliability review and determined that Salem 1 and Salem 2 (the two small coal units) could de-list. The ISO review concluded, however, that the two larger units (150 MW Salem 3 and 430 MW Salem 4) were needed to operate the system reliably at peak load.

The economic consequences of rejecting the static de-list bids for Salem 3 and Salem 4 are that consumers will pay higher capacity prices to these two units than are paid to all the other capacity resources that were competitively purchased in third auction at a pro-rated cost $2.54/kW-month. The excess costs are summarized in Table 3.

For the fourth forward capacity auction static de-list bids were again submitted for each unit. ISO New England conducted its reliability analysis and determined that, as for third auction, the two smaller units were not needed but the two larger units were still needed for reliability.

Table 3. Salem Harbor Participation in FCA

Salem Harbor	Unit #3		Unit #4	
	FCA 3	FCA 4	FCA 3	FCA 4
Unit Capacity, MW	140	140	437	437
Pro-rated clearing price, $/kW-month	2.54	2.52	2.54	2.52
De-list bid price as accepted by FERC, $/MW	5.33	5.005	5.33	5.005
Annual cost over market rate, $ mln	4.71	4.20	14.69	13.10

Based solely on capacity clearing prices, the rejected static de-list bids will provide up to $19.4 million in additional revenues in 2012-13 and $17.3 million in additional revenues for 2013-14.[60] Table 3 summarizes the additional revenues for Salem 3 and Salem 4.

The total additional payments of approximately $37 million over two years for the Salem units are costs that New England consumers would not need to pay if other, lower-priced capacity resources had been selected in either auction.

One of the ironies of the Salem Harbor example is that these same units were the focus of a contested cost of service settlement proceeding in 2004. At that time, ISO New England identified and planned new transmission facilities that would solve the reliability issues that required the Salem Harbor units to be available. These transmission enhancements were completed in 2008 and have performed as expected. However, the resource topography in the Greater Boston area had also changed by 2008 because some other generation resources had retired. When ISO New England conducted its reliability analysis on the Salem Harbor units prior to the third forward capacity auction in October 2009, it found that despite the transmission enhancements over the past decade the Salem units were still needed to meet reliability standards. The Salem units have now submitted permanent de-list bids for the fifth forward capacity auction. Pursuant to the tariff rules for the forward capacity market (FCM), ISO New England is obligated to develop and implement an alternative that will allow the Salem units to retire.[61] The rules state that ISO New England should strive to implement a solution prior to the applicable delivery year, which for fifth auction is June1, 2014.

While an end to excess capacity payments may now be in sight, a solution could have been achieved much earlier if the ISO had been required to undertake an annual planning process that specifically addressed at-risk resources. As of 2004, there was no doubt that all of the Salem Harbor units were slated for retirement, yet there was no ongoing planning to ensure that the appropriate transmission enhancements would be in place to allow for delisting as planned in 2008. Remarkably, there was no analysis of how other retirements within the same region would impact the transmission system in light of Salem Harbor's anticipated delisting. Had the ISO been required to assess the impacts of likely retirements in its annual planning process, issues identified for the first time in 2009 would have been identified and either avoided or resolved earlier. In the absence of such planning, New England ratepayers have been forced to pay excessive costs for over a decade.

iii. Exelon RMR requests

Two Exelon plants in the PJM footprint in Pennsylvania are further examples of the types of at-risk generation that need to be addressed in the planning process.

Cromby Unit No. 2 (Cromby) is a 201 MW peaking unit running on either natural gas or fuel oil, and Eddystone Unit No. 2 (Eddystone) is a 309 MW coal unit. Both units are operated by Exelon Corporation. Both of these units failed to clear in the PJM capacity auctions for the 2011/2012

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[60] All capacity market revenues are subject to adjustment for various factors including Peak Energy Rents (PER) and availability penalties. The revenues for the Salem units could be slightly less than our calculated amounts.

[61] Market Rule 1, Section III.13.2.5.2.5(g).

and 2012/2013 delivery years.[62] On December 9, 2009, Exelon provided notice to PJM of its intention to deactivate Cromby and Eddystone, effective May 31, 2011. Exelon explained that its deactivation decision was based on the uneconomic continued operation of the units due to their age and the costly investment needed to meet environmental regulations.[63]

PJM conducted a deactivation study and concluded that Cromby and Eddystone were needed beyond their requested deactivation date for reliability purposes, pending the completion of transmission upgrades. Cromby is needed through May 31, 2012 and Eddystone is needed through December 31, 2013.[64]

Exelon agreed to continue operation of Cromby and Eddystone in return for an RMR agreement. On June 9, 2010, Exelon filed a proposed RMR rate schedule according to which Exelon would recover its costs of operating Cromby and Eddystone beyond May 31, 2011 through a three-part cost of service rate. The three parts include a monthly fixed-cost component to recover capital and fixed costs through a traditional cost of service mechanism, a project investment tracker mechanism to recover Exelon's actual investment costs associated with emissions controls, and a variable cost reimbursement mechanism to recover Exelon's variable fuel, emissions, chemicals, auxiliary power, and incremental insurance costs.

Exelon's proposed cost of service rate is based on an annual revenue requirement of $31.7 million for Cromby and $96.6 million for Eddystone.[65] There is no certainty that the Commission will approve the requested annual recovery for each of these units.[66] Nonetheless, all the payments ultimately approved can be considered excessive costs. Because neither unit cleared PJM's capacity auctions for the 2011-12 or 2012-13 delivery years, neither unit is providing a capacity service through PJM's capacity market. PJM has purchased other units in those auctions to satisfy its capacity requirement. Pursuant to the RMR operating agreement for these two units, they are both prohibited from participating in any future PJM capacity auctions.[67]

This result imposes excessive costs on consumers because they have purchased all the necessary capacity through the PJM capacity market **and** they will pay the full RMR contract costs for the Cromby and Eddystone units. These RMR contract costs could be entirely avoided if the units retired. PJM is optimistic that transmission upgrades will allow Cromby to retire in May 2012 and Eddystone to retire in December 2013, but the operating agreement allows for additional RMR payments (terms to be determined) if either unit is still needed. Table 4 below shows the excess cost to consumers for the Fixed Cost portion if the proposed recovery is

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[62] Those auctions occurred in February 2008 and 2009, respectively.
[63] FERC Docket No. ER10-1418-000, Order Accepting and Suspending Tariff Filing, Subject to Refund and Establishing Hearing and Settlement Procedures at ¶ 4, Issued September 16, 2010. Available at: http://www.ferc.gov/whats-new/comm-meet/2010/091610/E-11.pdf
[64] *Id.*, at ¶ 5.
[65] *Id.*, at ¶ 9. The Cromby value of 31.7 million includes $154,053 requested for the Cromby Diesel unit, a small diesel generator that is used to start the larger Cromby unit.
[66] *Id.*, at ¶ 22. One contested issue in the proceeding is the amortization of investments over the remaining life of the units. The PJM Market Monitor has requested more information to justify the 36 month and 24 month depreciation schedules for Cromby and Eddystone respectively. It is that uncertainty (how long the plant will operate) that contributes to the controversy about the appropriate annual dollar recovery to charge to consumers.
[67] *Operating Procedures for Cromby Generating Station Unit No. 2 and Eddystone Generating Station Unit No. 2 as Required for Reliability*, May 27, 2010 at page 3, section 2.b. Available at: http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/must-run-operating-procedures.ashx.

approved by the FERC.[68] The excess costs do not include the "project investment tracker" costs which are unknown at this time.

Table 4. RMR Payments to Cromby 2 and Eddystone 2

Unit	2011/2012	2012/2013	2013/2014	3-Yr Total
Cromby 2	31,548,701	-	-	31,548,701
Eddystone 2	96,577,979	96,577,979	48,288,990	241,444,948
			Total	**272,993,649**

As noted in the Exelon presentation cited in this report that identified likely retirements of its coal units, Exelon anticipates the economical retirement of 11 GW of its coal plants in the PJM footprint. Cromby and Eddystone represent about 500 MW or less than 5% of Exelon's anticipated uneconomic generation.

Given the much larger quantities of resources that may seek deactivation in the coming years due to more stringent EPA rules, PJM needs to develop better planning criteria to identify these at-risk resources and identify least-cost solutions. Otherwise, PJM (and other planning authorities) will have little choice but to enter into RMR agreements with more and more resources. As demonstrated by the Cromby and Eddystone examples, these RMR agreements are likely to impose excessive costs on consumers until the necessary infrastructure improvements can be implemented to allow the retirement of the units.

iv. Hudson RMR case

Hudson Unit No. 1 (Hudson) is a gas-fired unit with a nameplate capacity of 355MW, which due to its inefficiency operates at a very low capacity factor of 2.1%.[69] The low capacity factor means that out of 8,760 hours in a year, the Hudson unit may produce electricity, on average, less than 200 hours a year. In addition, the actual qualified capacity eligible to offer into the PJM capacity market was established at 270 MW (due to age and poor performance) after its annual test prior to the June 1, 2010 delivery year.

In 2004, PSEG Fossil informed PJM of its intention to retire this Hudson unit due to its inefficiency and the high level of investment needed for its future operation. The retirement would have been effective December 7, 2004, absent an acceptable compensation agreement with PJM. PJM conducted a study to analyze the impact of Hudson's retirement on system reliability and

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[68] These are "excess costs" because consumers are already paying for all the necessary capacity to replace these units, and any energy production (if the units are ever needed to run) will be separately compensated through the variable component of the RMR agreement.

[69] Capacity factor as of 2004.

concluded that Hudson was needed beyond the proposed retirement date to maintain system reliability through at least the summer of 2008.[70]

In 2005, the PSEG Power Companies filed a tariff based on a cost of service analysis, in which they proposed to recover $17,269,948 million per year for fixed costs in order to maintain Hudson and ensure its availability. PJM subsequently settled for a reduced annual fixed revenue requirement of $14,512,408. There were two other components to the proposed tariff: a project investment tracker that would allow recovery of capital investments needed to keep the plant operating; and a variable fuel & maintenance element to allow recovery of any energy production if Hudson was asked to produce electricity rather than sit idle as a reserve unit.

Hudson participated and cleared in PJM RPM capacity auctions for three delivery years, 2007-08, 2008-09, and 2009-10. For the next two delivery years of 2010-11 and 2011-12, Hudson bid into the auctions but did not clear. In each auction, PJM determined that Hudson was still needed for reliability so the RMR contract continued. Hudson did not participate in the auctions for the 2012-13 and the 2013-14 delivery years because it intended to retire by then.

In October of 2010, the PSEG companies filed their annual update with the Commission regarding their anticipated future costs. PSEG provided two different estimates for the project investment tracker expenses: one schedule based on the retirement of Hudson in May 2012, and a second schedule based on Hudson continuing to operate through May 2014.

Table 5 below provides a summary of the recoveries requested by PSEG and an estimate of the capacity revenues that Hudson could have earned in each annual capacity auction.

[70] Docket No. ER05-644-000, PSEG Filing, February 24, 2004, pp. 4-5; Docket No. ER05-644-000, PSEG Stipulation and Agreement, September 23, 2005, p. 3; Docket No. ER05-644-000, PSEG Informational Filing, October 1, 2010, pp. 1-3.

Table 5. Hudson 1 RMR and RPM Revenues

	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014
Fixed Revenue Requirement Component, $	14,512,408	14,512,408	14,512,408	14,512,408	14,512,408	14,512,408	14,512,408
Project Investment Tracker Payments (Retirement Case), $	2,232,054	2,232,054	3,867,527	7,726,500	-	-	-
Total RMR Costs (Retirement Case), $	16,744,462	16,744,462	18,379,935	22,238,908	-	-	-
Project Investment Tracker Payments (Continued Operation Case), $	2,232,054	2,232,054	3,867,527	5,672,000	29,205,500	30,706,000	5,880,500
Total RMR Costs (Continued Operation Case), $	16,744,462	16,744,462	18,379,935	20,184,408	43,717,908	45,218,408	20,392,908
RPM Zonal Price (PS Zone), $/MW-day	197.16	150.53	196.53	174.29	110.04	162.87	245.09
Available Capacity, MW	~270[71]	~270	~270	270	270	270	270
Capacity Market Revenue	19,430,118	14,834,732	19,368,032	17,176,280	10,844,442	16,050,839	24,153,620
RMR - Capacity Revenue (Retirement Case)	-2,685,656	1,909,731	-988,097	5,062,629	-	-	-
RMR - Capacity Revenue (Continued Operation Case)	-2,685,656	1,909,731	-988,097	3,008,129	32,873,466	29,167,570	-3,760,712

There is some uncertainty regarding the values in the table. The capacity rating of 270 MW is based on a test in 2010. It is possible that Hudson had somewhat higher capacity ratings for the delivery years prior to June, 2010. A higher capacity rating would provide additional revenues to PSEG from the PJM capacity auctions. Nonetheless, even at the 270 MW rating, the capacity market revenues exceed the fixed recovery and investment tracker payments in two of the three years that Hudson cleared the capacity market auctions (2007-08 and 2009-10). RMR revenues in excess of capacity market revenues are largest in 2011-12 and 2012-13, and the net values of $32.8m and $29.2m in the last row would be excess costs. But Hudson did not clear in the 2011-

[71] 2010 PJM summer verification test identified Hudson's available capacity of 270MW, as reported in the Docket No. ER05-644-000, PSEG Informational Filing, October 1, 2010, pp. 1-3. We also use the value of 270MW as a proxy for Hudson's available capacity in 2007/08, 2008/09, and 2009/10 delivery years.

12 auction and did not offer into the 2012-13 auction, so the excess costs could be the entire reliability payments of $43.7m and $45.2m respectively.

The important issue here is that the inclusion or exclusion of reliability units from the PJM capacity market can have a major impact on the excess costs that consumers pay. A unit such as Hudson that clears in the capacity market when prices are high, and then does not clear when prices are low but is nevertheless paid under a reliability agreement, has no incentive to provide power at competitive rates. PSEG will get paid no less than the reliability agreement under all circumstances and possibly more if market prices are high. This result is at cross-purposes with the way a capacity market is intended to function; resources are not supposed to be able to alternate between cost-of-service compensation and market compensation.

Moreover, capital improvements may be covered under the reliability agreement in anticipation of retirement. As shown in Table 5, PSEG anticipates Investment Tracker payments of about $16 million over four years for the Retirement Case and deactivation at the end of the 2010-11 delivery year. For the Continued Operation Case through the 2013-14 delivery year, PSEG estimates an additional $63 million dollars in new investment for the three additional years. This is a steep price for just three more years of useful life. And there is a possibility that once the investments are paid for pursuant to the reliability agreement that the Hudson plant may choose not to retire after the 2013-14 delivery year. Better planning criteria might avoid these uneconomic investments and continued excessive costs by having infrastructure in place to allow the unit to retire.

G. Summary of RMR Case Studies

These examples of resources that receive out of market compensation (either through capacity market rules or traditional cost of service RMR contracts) illustrate the need for planning authorities to develop new criteria and mechanisms to address the reliability challenges that many of these aging resources pose. In light of the prevailing estimates that as much as 60,000 MW of coal-fired generation is likely to retire in the next several years, planning authorities must accelerate the development of the analytical tools they will need to plan for and accommodate these retirements expeditiously. The alternative is excessive costs to ratepayers potentially paired with periods of environmental non-compliance, a lose-lose result for consumers that are obliged to pay uncontrolled plants to continue polluting. The FERC can provide valuable guidance and assistance to the planning authorities through its current NOPR process.

Despite the development of three-year forward capacity markets in New England and PJM, the excessive costs associated with RMR contracts continue. Even with the specific tariff rules in New England that make the implementation of alternatives a priority, it is uncertain if the Salem units, originally identified as at-risk in 2004, can be permanently retired by June 1, 2014.

While forward capacity markets are helpful innovations, they cannot by themselves ensure cost-effective, forward-looking responses to retirements. The Commission needs to require planning authorities to be actively evaluating resources and determining the risk factors before a resource owner, struggling to maintain economic viability, finally decides to seek retirement. This is particularly true in light of looming, large-scale retirements of coal-fired resources. To avoid many years of excessive costs, planning authorities need to be aggressively identifying and implementing lower cost solutions, whether they may be investments in transmission, generation, or demand resources (or a combination thereof).

3. Energy Efficiency Impacts

In addition to federal regulations that will impact the generation mix across the country, consideration of state mandates in the transmission planning process is essential. The NOPR identifies renewable portfolio standards as a key consideration, which undoubtedly they are. Planning that accounts for state energy efficiency standards is crucial as well. Relative to the above discussion of anticipated coal plant retirements, energy efficiency is particularly important in that it can effectively offset the impact of reduced generator capacity.

Many states have adopted energy efficiency resource standards through legislative or regulatory commission actions. These standards often are established to achieve certain percentage reductions in gross energy usage on an annual basis. Other states have adopted a standard of "all cost-effective energy efficiency," a standard that pursues all measures that provide net savings. With either approach, the objective is to acquire resources through demand reductions, improved efficiency, and load management that can defer new generation and transmission additions.

The challenge for transmission planning is to incorporate these state standards into the planning process to avoid or defer transmission upgrades and/or generation investments predicated on load growth assumptions that do not account for the impact of aggressive implementation of energy efficiency programs.

A. Impact of Energy Efficiency on Load Forecast

Load forecasts are the starting point for all transmission planning exercises. Future loads will determine the need and timing for development of new generation resources and transmission infrastructure. Traditional approaches to load forecasting have used one of two methods (and sometimes a combination).

Some planning authorities aggregate the individual load forecasts of their member distribution companies. They often reconcile the non-coincident peak loads for individual companies to determine a regional coincident peak that becomes the regional load forecast for planning purposes.

Other planning authorities use an econometric forecast to estimate future loads. Econometric forecasts utilize projections about future economic activity, personal income, job growth, or other indexes to estimate future load growth. Some planning authorities may use a combination of approaches or compare one approach to the other.

Estimates of annual peak load growth have been decreasing over the years. For the most part, these lower growth estimates reflect both greater efficiency in energy use and the demise of many energy intensive industries in the United States— for example the steel, aluminum, automobile, and heavy equipment manufacturing industries.

Some of the more dramatic reductions in peak load growth, as well as overall electricity consumption, have occurred in states that are aggressively implementing energy efficiency programs. In addition, many states have committed to aggressive energy efficiency standards that establish specific goals in annual energy reductions and related reductions to peak load growth. A few states have adopted a standard of "all cost-effective energy efficiency" as the standard to be met by their local utility providers of energy efficiency services.[72]

In order to evaluate future infrastructure needs in a system planning process, a planning authority needs to start with a good forecast of future peak loads and overall energy consumption. Implementation of EE programs can have significant impacts on these forecasts.[73]

B. Case Studies

To better understand the impacts of energy efficiency programs, we reviewed load forecasts in three regional transmission organizations (RTOs): the Midwest ISO; ISO New England, and PJM. We took current load forecasts and adjusted the peak loads based on different assumptions of EE program implementation.[74] The results illustrate the potential for excessive infrastructure investment.

We developed four estimates of energy efficiency potential through 2030 and compared them to a baseline projection of future peak demand. The first estimate used EE penetration rate assumptions developed by Global Energy Partners.[75] That estimate assumes EE ramping up to 1.0% of annual energy consumption in 2011; dropping to 0.9% of annual energy consumption in 2016; and then dropping to 0.3% in 2020 and 0.1% in 2025. Although we disagree with Global Energy Partners assumptions about diminishing EE potential after 2015, we used their assumptions for the first case: 2010 RTO assumptions. We label this the RTO Assumptions Case for this report.

The second estimate used a constant 1% from 2011 through 2030 as a correction to Global Energy Partners' overly conservative assumptions. We label this the Modified RTO Assumptions Case for this report.

The third estimate used the same 1% from 2011 to 2015. We then ramp up the annual energy savings to 1.4% in 2020; and then hold it constant (at 1.4%) to 2030. This estimate of 1.4% reflects the annual energy savings targets developed through multiple studies of existing state mandates.[76] We label this the Current Programs Case for this report.

The fourth estimate uses the same 1% estimate from 2011 to 2015. We then ramp up the annual energy savings to 2% in 2020 and then hold constant (at 2%) to 2030. This estimate of 2% reflects the highest penetration rates of the leading states.[77] We label this the Best Practices Case for this report.

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[72] *See*, Appendix B and tables of state goals and achievements.
[73] For this report, we have included the impacts of energy efficiency programs only. We have not included the peak load impacts of demand response programs or distributed generation initiatives.
[74] We based the analysis on a similar analysis we did for a report on demand side resource potential in MISO. *Demand Side Resource Potential: A Review of Global Energy Partners' Report for Midwest ISO*, September 3, 2010.
[75] GEP developed their estimates from surveys of individual utilities in the MISO footprint.
[76] *See*, Appendix B for table summarizing the studies.
[77] *See*, Appendix B for table of leading states.

For the ISO New England and PJM case studies, we varied the RTO Assumptions Case to reflect their present practices for estimating EE penetration. The specifics for each RTO are described below in their respective sections.

All of the cases were built upon assumptions about EE penetration levels expressed as "reductions to annual energy consumption." The results presented, however, are all expressed as annual peak loads (not annual energy consumption). To do this, we used the conversion factor developed in our earlier report to adjust the energy savings into peak load savings.[78]

i. MISO

As we explained above, the RTO Assumptions Case uses the Global Energy Partners' assumptions about declining EE penetration rates from its report to MISO: 1% by 2011; 0.9% starting in 2016; 0.3% starting in 2020; and 0.1% starting in 2025. Although MISO has not adopted these assumptions, they reflect a conservatism that ISO New England and PJM have adopted.

The other estimates (Cases 2-4) shown in Figure 3 are based on the methodology described above. The Modified Assumptions Case uses a constant 1% annual energy reduction. The Current Programs Case uses a constant 1.4% starting in 2020. The Best Practices case uses a constant 2.0% starting in 2020.

[78] In order to calculate the annual peak load savings, we found a "kW savings per MWh savings" ratio from GEP total energy and load savings for each five-year block (i.e., approximately 0.197 kW/MWh ratio). Next, we applied this ratio to the annual energy savings estimates we developed for the alternative scenarios to obtain annual peak load savings. More specifically, we converted annual GWh energy savings from EE (calculated as a percentage of the previous year's net energy) into MW peak load savings from EE for each year in each alternative scenario. Finally, given annual peak load savings from EE, we calculated average annual rate of peak load savings from EE. With this methodology, 2% annual energy savings form EE corresponds to 1.89% annual peak load savings, and 1.4% annual energy savings corresponds to 1.33% annual peak load savings.

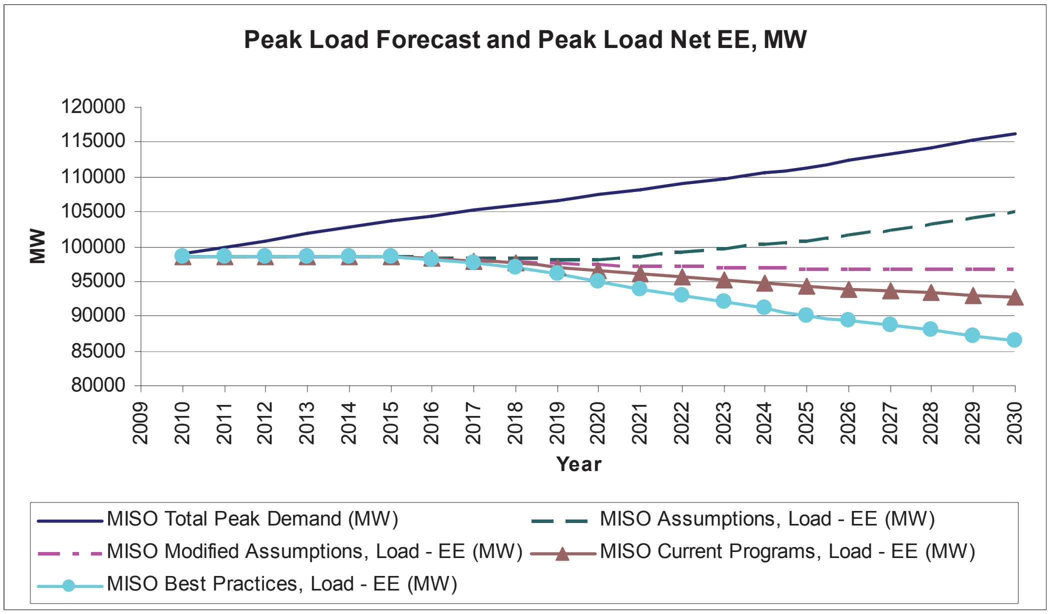

Figure 3. MISO EE Scenarios

The important planning issue for MISO that these cases illustrate is that the historic, constant annual increases in energy consumption that planners have relied on for decades is not a good predictor of future peak loads because these increase do not reflect new and enduring trends that flow from energy efficiency programs.[79] This graph isolates the potential for EE programs to maintain, or even diminish, current peak loads for the next two decades. The challenge for planning entities has always been to predict the pace of growth, the certainty of growth was assumed. The adoption of state goals to reduce demand growth through the implementation of energy efficiency programs is a major change. The historic linkage between economic growth and energy growth has weakened in recent years and may disappear completely in the near future.[80]

ii. ISO New England

The RTO Assumptions Case for ISO New England is based upon the adjustments that ISO New England makes to its load forecasts to reflect the results of its forward capacity auctions. To date, there have been four auctions. ISO New England adjusts its estimate of future peak loads by the amount of EE MW that cleared each auction. Staring in 2015, the ISO assumes no additional EE penetration. For this graph line, there is no need to convert energy values to peak load.

The Modified RTO Assumptions Case for ISO New England is based upon a request in the Planning Advisory Committee process to conduct an economic analysis of the New England

[79] As recently as the 1950s annual electricity growth would track economic growth one for one in percentage terms. Since 1980, the track line has been closer to half as much annual growth in electricity consumption as economic growth. With improved efficiency in electricity uses, the track line for electricity consumption growth can go much lower to one-third or one-quarter of annual economic growth on a percentage basis.

[80] There are other factors, besides direct investment in EE programs that also contribute to this fundamental change in the bulk power system. They include renewable portfolio standards, carbon abatement programs, direct subsidies for particular resources such as wind and solar, and feed-in tariffs for specific resources.

system through 2030. That economic study uses the actual forward capacity auctions results for the reductions through the 2014 power year and then assumes EE penetration rates through 2030 using the average annual capacity reductions of the first three auctions. The average after the first three auctions is 234 MW, or slightly less than one percent of the annual peak load for each year. It is comparable to the 1% annual energy reduction cases used for MISO and PJM.

The Current Programs Case (ramping to 1.4%) and the Best Practices Case (ramping to 2.0%) are based on the same assumptions used for MISO (and PJM).

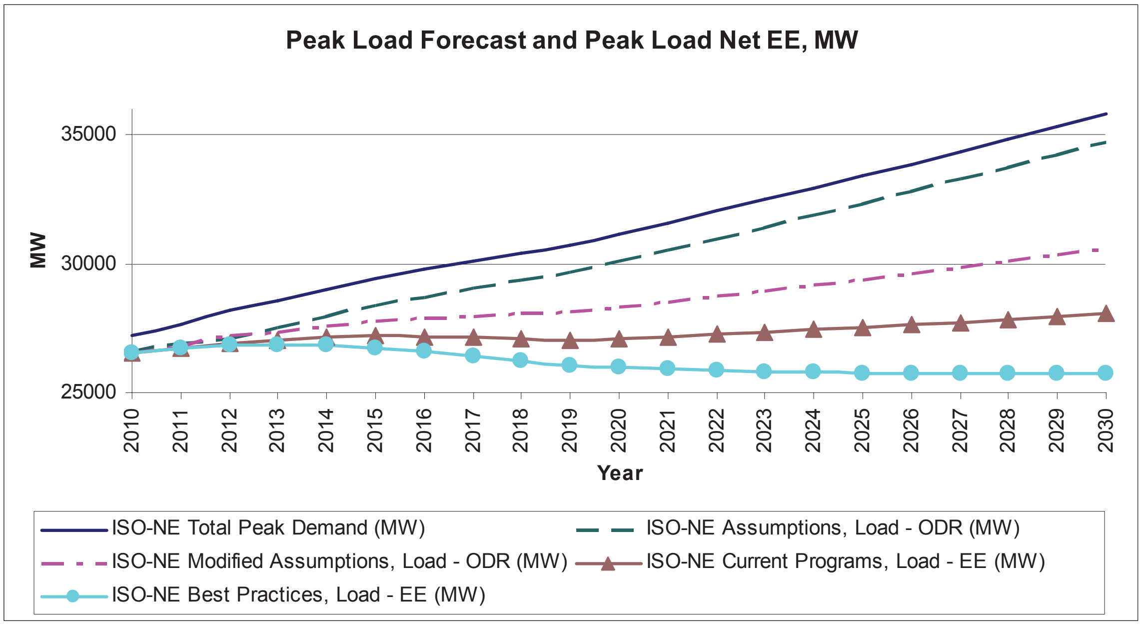

Figure 4. ISO New England EE Scenarios

The same planning issue pertains to New England as it does for MISO: constant annual growth in peak loads is no longer a reasonable assumption for planning entities to make. If New England maintains its current average EE investments, peak load remains constant for the next two decades. If New England achieves a Best Practices level of EE programs, then peak loads will steadily decline for the next twenty years. Some of the same macroeconomic trends that apply to MISO will also apply to New England, so peak load reductions may decline for reasons in addition to the levels of investment in traditional EE programs.

iii. PJM

The RTO Assumptions Case for PJM is based upon the results of two forward capacity auctions in PJM.[81] It is likely that EE participation will increase in future capacity auctions as more states within PJM's footprint expand their EE programs and develop the measurement and verification processes that will support their participation.[82] Nonetheless, for this case, we used only results through the 2013-14 delivery year and assumed no additional EE penetration.

The Modified RTO Assumption Case for PJM is based upon the annual base residual auction results for 2010 delivery year and then ramps up the EE penetration rate to 1% in 2020 and holds that 1% rate constant through 2030.

The Current Programs Case for PJM is based upon the annual base residual auction results for 2010 delivery year and then ramps up the EE penetration rate to 1.4% in 2020 and then holds that 1.4% rate constant through 2030.

The Best Practices Case for PJM is based upon the annual base residual auction results for 2010 delivery year and then ramps up the EE penetration rate to 2% in 2020 and then holds that 2% rate constant (2%) through 2030.

The PJM Assumptions case is almost the same as the initial PJM peak load forecast. Similar to ISO New England, PJM only accounts for energy efficiency that is bid into its RPM capacity market. PJM only began allowing energy efficiency resources to bid starting in the February 2009 base residual auction (for the 2012-13 delivery year). Very few energy efficiency resources were bid into the first auction due to the short advance notice. We have adjusted PJM's load forecast to incorporate the 2009 and 2010 auction results, but they have only a minimal impact on the future peak loads. It is likely that over the next few years that larger quantities of energy efficiency resources will qualify for and clear in the annual capacity auctions.

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[81] PJM has a three-year forward capacity market similar to ISO New England. It is based upon a reliability pricing model and annual base residual auctions each year. Energy efficiency resources have participated in the annual auctions staring in 2009 (for the 2012-13 power year). Current EE participation is about 0.1% of PJM's annual capacity need.

[82] *See*, Appendix D. There was a 20% increase in cleared energy efficiency resources from the 2012-13 auction (568 MW) to the 2013-14 auction (679 MW)

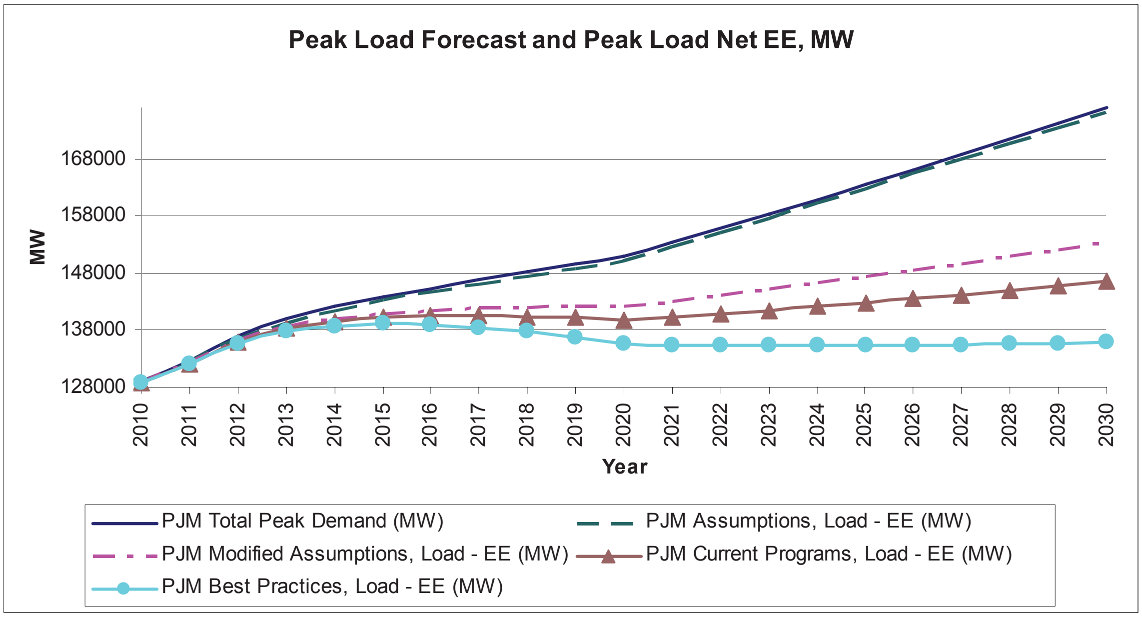

Figure 5.PJM EE Scenarios

The PJM cases have less overall impact on future peak loads due to the slower ramping up of programs that is common to all the PJM cases. PJM also has a stronger underlying annual growth rate assumption than the other two RTOs.[83] Despite this slower pace of energy efficiency program implementation, PJM's peak loads in the Current Programs Case is only a little over 10% higher after 20 years. In the Best Practices Case, PJM's peak load increase is reduced to just over 5% for the twenty years.

iv. Summary for RTOs

Table 6 below provides a summary of all the cases for each RTO. This summary shows that there are substantial reductions to future load estimates when modest, currently achievable levels of energy efficiency investments are made.

[83] PJM 2009 Regional Transmission Expansion Plan. Available at: http://www.pjm.com/documents/reports/~/media/documents/reports/2009-rtep/2009-rtep-report.ashx

Table 6. Summary of EE Scenarios in 3 RTOs

Scenario	MISO	ISO-NE	PJM
Base Peak Load (MW), 2010	98,963	27,190	129,102
Base Peak Load (MW), 2030	116,165	35,808	176,956
RTO Assumptions, Cumulative EE (MW), 2030	11,233	1,073	679
Load - EE (MW)	104,932	34,735	176,277
Δ (RTO Assumptions Net Peak Load 2030 - Base Peak Load 2030), %	-9.67%	-3.00%	-0.38%
RTO Modified Assumption, Cumulative EE (MW), 2030	19,373	5,187	23,516
Load - EE (MW)	96,792	30,621	153,440
Δ (RTO Modified Assumptions Net Peak Load 2030 - Base Peak Load 2030), %	-16.68%	-14.49%	-13.29%
RTO Current Programs, Cumulative EE (MW), 2030	23,392	7,723	30,250
Load - EE (MW)	92,773	28,085	146,706
Δ (RTO Current Programs Net Peak Load 2030 – Base Peak Load 2030), %	-20.14%	-21.57%	-17.09%
RTO Best Practices, Cumulative EE (MW), 2030	29,618	10,075	40,984
Load - EE (MW)	86,547	25,733	135,972
Δ (RTO Best Practices Net Peak Load 2030 - Base Peak Load 2030), %	-25.50%	-28.14%	-23.16%

Based on an average of savings from existing state EE programs (the RTO Current Programs case in the table), all three RTOs would reduce peak loads in 2030 by almost 20% below a no-EE base case. In addition, peak loads for MISO in 2030 would be lower than its 2010 peak loads; peak loads for ISO-NE would be about the same in 2030 as in 2010. Maintaining a constant peak load over twenty years for ISO-NE, or decreasing it as in the MISO case, would have profound impacts on system planning needs.

From a planning perspective, better analysis of state program impacts will result in better estimates of future peak loads, or as we do for our analysis, describe a range of future peak loads. The Commission can provide detailed guidance to planning authorities on the importance and value of analyzing state policies on energy efficiency (and other related policies such as renewable portfolio standards and feed-in tariffs) through the final rules it adopts in this proceeding. The ultimate impact of these efforts will be to allow planning authorities to identify the best system enhancements to recommend and avoid unnecessary or duplicative solutions that create excess costs passed through to ratepayers.

4. Recommendations

Our detailed review of how revised EPA regulations can contribute to the quantity of at-risk resources and how state energy efficiency mandates have the potential to substantially mitigate peak load growth persuades us that planning authorities must consider public policies in their efforts to maintain reliable and cost-effective electricity service in their regions. The case studies illustrate a variety of ways that excessive costs can be incurred through failures to anticipate impending retirements of uneconomic units and the inability to provide load forecasts that can assist in targeting future bulk power system investments.

In this section, we make recommendations for the Commission to implement in this rulemaking that will address the two public policy issues analyzed in this report **and other public policy issues** that planning authorities need to better understand as part of their planning responsibilities. All of these policy initiatives are important features of the future landscape in which planning authorities will be recommending system enhancements.

The NOPR's proposal to require planning authorities to include federal and state public policy mandates has the potential to improve analyses and provide more targeted information about bulk power system enhancements. With a more dynamic planning process, one that incorporates uncertainties around load growth, responsive demand, new technologies, and environmental regulations, ratepayer funded investments in transmission and traditional generation resources can be most cost-effective and improve overall system efficiency.

To ensure that planning authorities provide a proper structure for evaluating federal and state public policies, the Commission could provide useful guidance with respect to the consideration of public policy mandates in at least four planning areas:

1. At-risk and retiring generation;
2. Integrating new generation resources;
3. Minimizing load growth with energy efficiency resources; and
4. Leveraging demand response resource to meet demand and energy needs.

A. Criteria for Incorporating Public Policies

Our first set of recommendations relates to policies that are likely to elicit retirements and assessment of "at-risk" generation. Generation could be at-risk due to age, competitive markets, new regulations, renewal of licenses, or other reasons related to public policy mandates. Each planning authority needs to develop criteria for evaluating and assessing at-risk generation within its planning footprint. The types of public policy mandates that would require consideration in this process are state and federal environmental mandates including EPA regulation of air pollution, water pollution, and waste disposal, regional initiatives to reduce carbon emissions including the Regional Greenhouse Gas Initiative, and any federal commitments to reduce carbon emissions.

This set of criteria may be particularly important in light of the large quantity of generation that is likely to become at-risk once new EPA regulations are final in 2011 and 2012. Our analysis of just a few hundred MW of at-risk generation (the cases in this report) show that annual excessive costs would exceed $50 million a year and approach $100 million per year if even small, marginal units are kept operating for reliability reasons. If 60,000 MW of coal-fired generation is likely to become at-risk by 2015 to 2016, the excessive costs to consumers could easily be in the billions of dollars on an annual basis. Given that EPA regulations will create a reasonable deadline for compliance, there is time now to avoid uneconomic results. In short, addressing these issues sooner, rather than later, will allow planning authorities to develop alternatives in a timely, cost-effective manner.

The second set of criteria that needs to be developed by each planning authority relates to grid integration of new generation resources. Public policy mandates that must be considered in this context include state initiatives to maintain or expand the portion of load served by renewable resources. Some states also adopt specific target quantities of particular renewables such as wind or solar either through portfolio standards or feed-in tariffs. The Federal Tax Code is another example of a public policy initiative to support specific renewables through development tax credits. Tax incentives reduce the effective cost of a resource such as solar photo-voltaics. In the planning process, this “lower cost” value can be used to estimate penetration levels. Planning authorities need to develop ways of incorporating these state and federal initiatives into their assumptions about future resources. The criteria should compel assessments of both specific resources by fuel type and specific quantity targets for renewables.

The third set of criteria for planning authorities to develop relates to the determination of future load growth. These criteria need to address traditional econometric forecasting, adjustments for future efficiency standards and codes, and the impact of state/utility sponsored demand-side management programs. In addition, the development of small-scale distributed generation (e.g., combined heat and power, wind, solar photo-voltaics, bio-waste, and new technologies) will impact the bulk power system as a relatively inflexible load reduction. A good planning process needs to anticipate and adjust for these largely policy driven resource dynamics.

Finally, planning authorities need to develop planning criteria to address an important related issue: demand response. As both New England and PJM are discovering, the “simple” demand response model of interruptions during peak load events has evolved into a more complex issue of resource flexibility. When, and for how long, and how often can demand response resources be activated? Can demand resources effectively bid energy reductions into day-ahead energy markets? The Commission has been active over the years in encouraging the development of demand response resources. Planning authorities need to develop criteria for categorizing different types of “demand response” and neither over-estimate nor under-estimate the performance capabilities for resource adequacy analyses or contributions to balancing daily energy needs. Similar to state-adopted energy efficiency targets, some states establish target levels of demand response resources. These policy initiatives must also figure into the planning process.

B. Procedures to Monitor At-Risk and Retiring Generation

In addition to developing the criteria for defining at-risk and retiring generation, planning authorities need to develop a process by which at-risk generation is monitored for system planning processes. It is the consensus of most industry analysts that forthcoming EPA regulations will have a major impact on the ability of some fossil fueled resources to remain competitive. Each planning authority needs to catalog the resources in its planning footprint that meet appropriately defined at-risk criteria. This may involve a broad stakeholder process to develop the criteria that are filed with the Commission as part of the planning process pursuant to Order No. 890.

The Commission should require each planning authority to file an annual assessment of at-risk generation in its planning footprint as part of its annual system planning report. The assessment should include a process for monitoring at-risk generation with critical milestones identified. These critical milestones should include items such as effective dates of new regulations; transmission enhancements to allow retirements; and timing of upgrades to existing facilities to allow continued operation. The annual assessment should also explain how the planning authority is responding to retirement requests, how it is determining whether units must run for reliability, and what solutions it has identified to maintain grid reliability post-retirement. This information will be essential to cost-effective decision-making not only by grid operators but also by state utility commissions.

One specific option that planning authorities should be required to address is the use of targeted requests for proposals (RFPs) to address specific reliability issues. Basically, an RFP process solicits specific offers from resource providers (generation or demand resources) to address a particular reliability problem. This approach was used successfully in Connecticut for the period of time that Connecticut was resource deficient and was waiting for a transmission enhancement to be completed and put into service. The RFPs developed by ISO-NE for Connecticut paid a premium to providers of resources for a period of years based on their offers. Upon the implementation of New England's Forward Capacity Market in 2010, the RFP contracts and the RMR contracts ended.

In summary, these enhancements to the Order No. 890 planning rules will protect the public from both unnecessary and inefficient investments in transmission and generation infrastructure. In light of the substantial impacts that public policies can have on bulk power system costs, FERC action through detailed rulemaking is appropriate and necessary to meet the Commission's obligation to ensure just and reasonable rates under the FPA.

Appendix A. At-Risk Issues

The need for planning authorities to identify at-risk resources and determine their ability to contribute to reliable operation of the bulk power system is becoming more urgent every day. In this appendix, we provide some of the documents we have found that suggest ways to address this ongoing challenge. We chose documents from ISO New England and PJM because they both have well established stakeholder processes that produce annual assessments of their bulk power systems. Yet, despite their relatively advanced planning processes, both ISO New England and PJM continue to retain uneconomic generation resources due to their inability as planning authorities to resolve reliability concerns in a timely manner. Commission guidance to planning authorities through this rulemaking is essential to improve the planning process both for entities such as ISO New England and PJM and for entities that are well behind these two RTOs in their efforts to address at-risk generation.

Below is an excerpt from an ISO New England memo that identifies topics for discussion this fall between NEPOOL stakeholders and the ISO New England Board of Directors/Senior Staff.[84]

The following are the proposed topics for discussion.
1. Retirement or Unavailability of Oil-Fired Resources
New England's oil-fired generation resources, which were built as baseload or intermediate resources, are aging and rarely run. While they constitute roughly 25% of the region's installed capacity, they produce only about one to two percent of regional energy. Further, ***environmental regulation appears to be moving rapidly in a direction that will make it more expensive and more difficult for these resources to run****. Specifically:*

- *While they remain in service, what should the region do to ensure that these resources are available when needed?*
- ***How should their potential retirement be addressed? In particular, what are the implications for market design and power system planning?***

We have highlighted (in bold) two sections of the memo that are related to issues examined in this report regarding at-risk resources. These are issues that the Commission can address in the current NOPR or in other proceedings before the FERC. At a minimum, this memo demonstrates that ISO New England already has recognized the importance of these issues.

PJM has been monitoring generation retirement requests since 2003 and has included a section on generation deactivation requests in its annual Regional Transmission Expansion Report (RTEP) since 2005. Below we have included the deactivation summary from the most recent RTEP and the retirement requests list from PJM's website.[85] These two PJM documents are examples of the initial data gathering that all planning authorities need to conduct and publish in their annual transmission assessments.

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[84] These NEPOOL and ISO Board discussions occur twice each year. This memo is from ISO New England General Counsel Raymond W. Hepper and is dated October 26, 2010. It is for a meeting on November 18, 2010.

[85] 2009 RTEP Section 2 page 37.

FUTURE DEACTIVATIONS
(as of December 1, 2010)

Unit	Capacity	Trans Zone	Age (Years)	Official Owner Request	Requested Deactivation Date	Projected Deactivation Date	PJM Reliability Status[1]
Hunlock 3	45	UGI	48	1/16/2008	6/1/2010	6/1/2010	Unit being re-powered under interconenction project T117. Cap rights re-used.
Hudson 1	383	PS	39	9/8/2004	12/7/2004	9/1/2011	Reliability Issues Identified - Unit retained through summer 2011
Will County 1	151	CE	52	6/4/2007	9/2010	12/31/2010	Potential reliability issues identified - can be resolved by summer 2011
Will County 2	148	CE	52	6/4/2007	9/2010	12/31/2010	Potential reliability issues identified - can be resolved by summer 2011
Indian River 1	90	DPL	50	9/28/2007	5/1/2011	5/1/2011	Reliability issues identified and expected to be resolved by 5/1/2011
Benning 15	275	PEP	39	2/28/2007	5/31/2012	5/31/2012	Reliability issues identified and expected to be resolved by 5/31/2012.
Benning 16	275	PEP	35	2/28/2007	5/31/2012	5/31/2012	Reliability issues identified and expected to be resolved by 5/31/2012.
Buzzard Point East Banks 1, 2, 4-8	112	PEP	39	2/28/2007	5/31/2012	5/31/2012	Reliability issues identified and expected to be resolved by 5/31/2012.
Buzzard Point West Banks 1-8	128	PEP	39	2/28/2007	5/31/2012	5/31/2012	Reliability issues identified and expected to be resolved by 5/31/2012.
Cromby 1	144	PE	55	12/2/2009	5/31/2011	5/31/2011	Reliability analysis complete - Reliability Impacts identified - Results posted
Cromby 2	201	PE	54	12/2/2009	5/31/2011	12/31/2011	Reliability analysis complete - Reliability Impacts identified - Results posted
Eddystone 1	279	PE	49	12/2/2009	5/31/2011	5/31/2011	Reliability analysis complete - Reliability Impacts identified - Results posted
Eddystone 2	309	PE	49	12/2/2009	5/31/2011	6/1/2012	Reliability analysis complete - Reliability Impacts identified - Results posted
Kearny 10	122	PSEG	39	4/22/2009	6/1/2012	6/1/2012	Reliability analysis underway - along with potential transfer of capacity rights to new interconnection project(s)
Kearny 11	128	PSEG	40	4/22/2009	6/1/2012	6/1/2012	Reliability analysis underway - along with potential transfer of capacity rights to new interconnection project(s)
Kearny9	21	PSEG	43	4/21/2010	6/1/2013	6/1/2013	Reliability analysis underway - along with potential transfer of capacity rights to new interconnection project(s)
Cromby Diesel	2.7	PECO	43	5/27/2010	5/31/2011	5/31/2011	Reliability analysis complete - no impacts identified
Ingenco Petersburg Plant	2.9	DOM	20	7/16/2010	5/31/2013	5/31/2013	Reliability analysis complete - no impacts identified
Chesapeake 7	16	DOM	40	7/28/2010	7/28/2012	7/28/2012	Reliability analysis complete - no impacts identified
Indian River 3	169.7	DPL	40	8/13/2010	12/31/2013	12/31/2013	Reliability analysis complete - reliability impacts identified and expected to be resolved before unit is deactivated
Sporn 5	440	AEP	49	10/1/2010	12/31/2010	12/31/2010	Reliability analysis complete - no impacts identified
Baleville Landfill	3.8	PSEG	9	11/24/2010	2/22/2011	2/22/2011	Reliability analysis underway
Kingsland Landfill	2.8	PSEG	11	11/24/2010	2/22/2011	2/22/2011	Reliability analysis underway
TOTAL:	3448.9						

Table 2.11: Summary of Generation Deactivations in PJM Since 2003

TO Zone	Retirements (MW)	Pending Retirements (MW)	Deferrals (MW)	Totals (MW)
AE	74	0	0	74
AEP	230	0	0	230
ComEd	3,616	299	0	3,915
BGE	0	0	0	0
Delmarva	10	179	0	189
DLCO	0	0	0	0
JCPL	265	0	90	355
METED	20	0	20	40
PECO	253	933	0	1,186
PEPCO	18	790	0	808
PPL	285	45	0	330
PENELEC	391	0	19	410
PSEG	783	383	0	1,166
PJM Total	5,945	2,629	129	8,703

PJM has also begun raising issues related to at-risk resources with its stakeholders. Figure A-1 below is a slide from a PJM stakeholder meeting in October 2010. We also include three slides from an Exelon presentation to a PJM stakeholder group in July 2010 that provide a good summary of the issues that need to be more fully addressed by planning authorities.

Figure A-1.*Integrating State Policy*, Steven Herling, PJM Regional Planning, October 6, 2010.

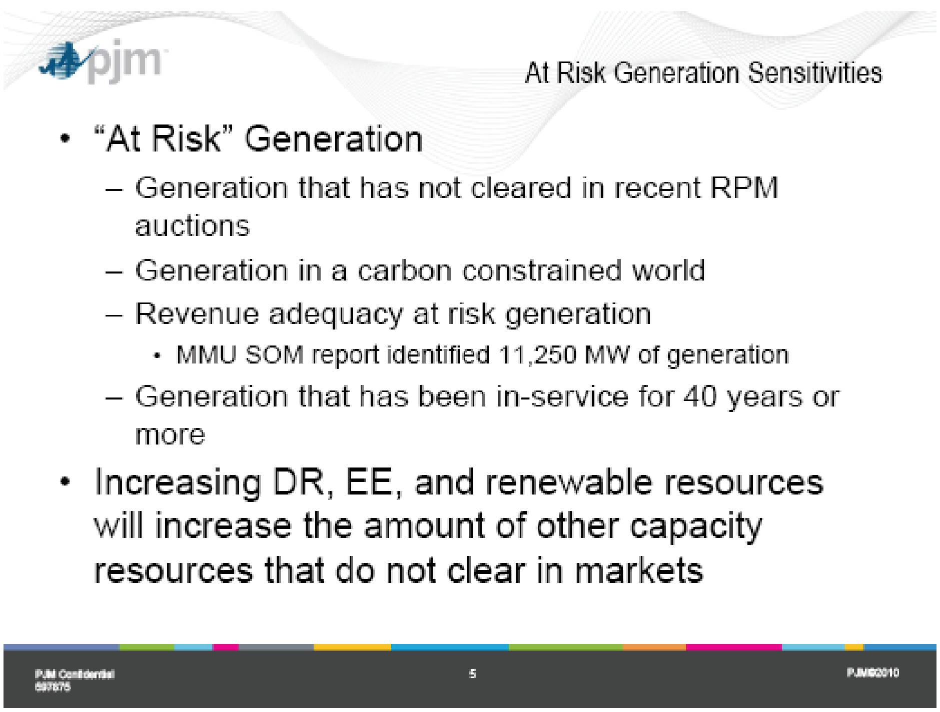

Figure A-2, Exelon slides *At-Risk Generation Retirement*, PJM TOA-AC Meeting, July 2010.

Generation Retirement

2

- ✓ Generation retirements expected to increase over the next several years
  - Increasing cost of operation for older facilities
  - Increased competition at wholesale (DR, Renewable Resources)
  - Decreased load due to economy
  - Increasing environmental regulations
  - Thousands of mws of existing generation not clearing RPM auction
  - PJM projected 28% reserve margin in 2010
  - Monitoring Analytics identified 11,250 MW of coal units did not recover avoidable costs in 2009

Exelon.

Generation Retirement Analysis Objectives

3

- ✓ PJM rule modification(s) to accomplish the following tenets:
  - Extended time for optimum planning, design, material procurement and construction of required transmission upgrades required for **announced** generation retirements
  - Assessment of **anticipated** generation retirements
    - – Identification of reliability impacts
    - – Scope of transmission upgrades
    - – Construction of transmission upgrades

Exelon.

Exelon Input for Improvements to Announced Generation Retirement

4

✓ Modification to PJM tariff 90 day notification requirement

- Longer notification requirement
- Transmission Owner ability to commit to schedule and cost details
  - Preliminary design and cost estimates
  - Internal approval processes
  - Detailed design, material procurement, transmission outage scheduling
- Shorter duration RMR if one is necessary

Exelon.

Appendix B. MISO EE Cases

Our analysis of the impact of energy efficiency programs on the Midwest ISO (MISO) load forecast builds upon a report by Global Energy Partners for MISO that evaluated energy efficiency and demand response potential within the MISO footprint. We made some alternative assumptions to those in the Global Energy Partners' report and provided those results to the MISO stakeholders in September 2010.[86]

In July 2010, Global Energy Partners (GEP) prepared a draft report [87] that established estimates of savings from demand response (DR) and energy efficiency (EE) resources for a twenty-year horizon, from 2010 through 2030. GEP developed a baseline peak demand and energy forecast from actual 2009 MISO utilities' peak load and energy sales data and projected the values of peak demand and energy use twenty years forward.

As a starting point, the GEP report assumes that in the first forecast year of 2010, EE accounts for 0.5% of total baseline peak demand and 0.5% of the baseline energy forecast. By 2030, the report projects that EE will account for 9.7% of the peak demand and 10.2% of the baseline energy forecast. GEP assumes, however, that the majority of savings from EE will accrue in the first ten years, while assuming almost no additional savings from EE in the second decade, as shown in Table 1 below. GEP developed their estimates of achievable potential of EE and DR, as well as forecasts of peak demand and energy, based on the data from 27 Midwest utilities. GEP's approach to peak load forecasting, called "MISO Assumptions" scenario, results in a gradual growth of net peak load through 2030, with the average annual growth rate of 0.32%.

There are several assumptions in the GEP draft report that produce overly conservative estimates of EE resource acquisitions through 2030 and, therefore, overstate the growth of peak loads and energy consumption. Among them is the assumption that EE resource acquisition will consistently decrease after the first five years. The acquisition rate drops to 0.9% in 2015, 0.3 % in 2020, and 0.1% in 2025. The premise for these assumptions is that there is a saturation level that exists for EE acquisition. The actual experience in EE programs has been that EE acquisition can (1) ramp upward for many years and (2) can maintain acquisition rates above 1% for many years. Moreover, GEP assumes a maximum potential for EE acquisition that is unrealistically low and ignores both emerging technologies and economies of scale that will allow EE programs to deliver even more dramatic gains over the next twenty years.

To demonstrate the significance of GEP's assumptions about diminishing EE resources, we adapted GEP's results to an assumption of a constant 1% annual EE resource, called "MISO Modified Assumptions" scenario. Our new results show the cumulative savings from holding the 1% acquisition rate constant after 2015. Total savings from EE increase from 58,605 GWH to, 97,338 GWH in 2030. Total energy consumption in 2030 would decrease from 509,322 GWH to 469,758 GWH. Such a modification to the GEP scenario results in nearly flat energy consumption and peak loads through 2030.

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[86] Synapse Energy Economics. September 2010 "Demand Side Resource Potential: A Review of Global Energy Partners' Report for Midwest ISO"

[87] Global Energy Partners. July 2010. "Assessment of Demand Response and Energy Efficiency Potential for Midwest ISO." Draft. Report #1314.

The savings goals established by several MISO states and the actual experience of states with EE programs indicate that incremental cost-effective savings from EE will continue to accrue after 2020. These savings will come from new emerging technologies and technological improvements and from economies of scale as more EE measures are installed.

Given states' EE goals and the actual achieved EE savings to date, we consider GEP's estimate of 10.2% total energy reduction by 2030 from EE to be an underestimation of the realistic achievable EE potential in the Midwest. Based on the estimates of EE potential in the studies summarized in the ECW study, Synapse determined an average annual achievable energy savings of about 1.4% per year.[88] Table D-1 below shows the studies that were used to develop the 1.4% estimate.

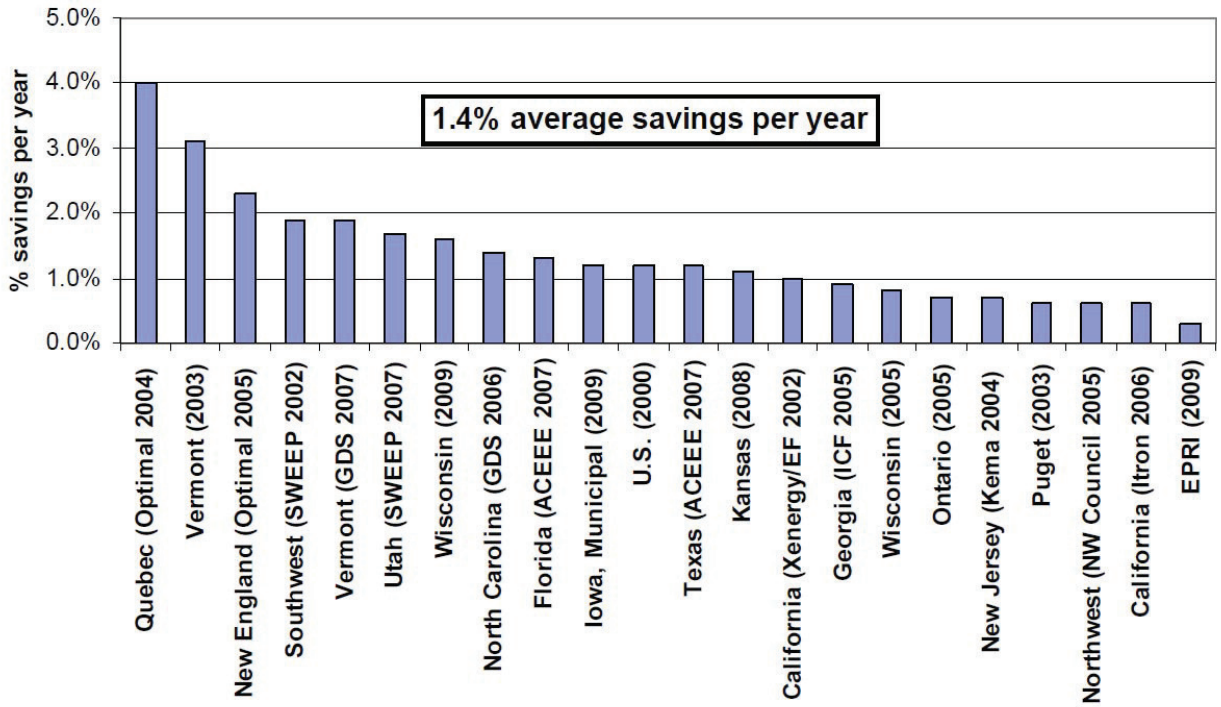

Figure D-1. EE Potential Study

This 1.4% scenario, which we label "MISO Current Programs" scenario, uses the same initial assumptions for 2010-2015 as those used in the GEP report (energy sales forecast and incremental annual savings from EE), then applies gradual annual increases in the savings rate from 1% in 2015 to 1.4% in 2020. We hold the annual savings from EE at a constant 1.4% rate for the remainder of the study period.

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[88] As reported in Synapse Energy Economics report "*Beyond Business as Usual: Investigating a Future without Coal and Nuclear Power in the U.S.*", May 2010, pp. 60-61.

However, since the purpose of this report is to estimate the effect of EE on peak load (rather than annual energy consumption), we convert the average annual **energy savings** from EE into average annual **peak load savings** from EE. In order to calculate the annual peak load savings, we found a “kW savings per MWh savings” ratio based on the GEP savings numbers (i.e., approximately 0.197 kW/MWh savings) and applied this ratio to the energy savings estimates we developed for the alternative scenarios. More specifically, we converted GWh energy savings from EE (calculated as a percentage of the previous year’s net energy) into MW peak load savings from EE.[89] After the conversion, the 1.4% average annual energy savings from EE translates to a 1.33% average annual peak load savings from EE.

In this modified scenario, called “MISO Current Programs” scenario, the cumulative savings from EE increase to 23,392 MW, compared to 11,233MW in the “MISO GEP” scenario. These cumulative savings result in the net peak demand of 92,773 MW in 2030, which is more than 12,000 MW lower than “MISO GEP” 2030 net peak demand.

The Midwest Governors Association adopted a goal of meeting 2 percent of the Midwest’s annual retail sales of electricity through EE by 2015. This 2 percent goal is an appropriate estimate of EE potential over the long term if all states adopted a “Best Practices” standard for their EE programs. A 2% estimate of achievable energy efficiency potential is also supported by the recent report for the Massachusetts Energy Efficiency Advisory Council from June 2009.[90] That report suggests that a reasonable long-term value for all available cost-effective energy efficiency savings is at least 2.5 percent per year over a ten-year horizon. The validity of a 2 percent target is also confirmed by the “best practices”, or the highest recent achieved efficiency savings levels, in the EE leading states and utilities, as shown in Table D-2 below. The top five performers in the table average over 2 percent annual energy savings. Importantly, the numbers for EE savings in the table only reflect savings from utility programs, and do not include any additional savings that accrue from updated building codes and appliance standards.

[89] We use a “kW savings per MWh savings” ratio of 0.197 kW/MWh, which is close to the average of annual “kW savings per MWh savings” ratios. We calculated the peak loads based on GEP’s numbers. “kW savings per MWh savings” ratios used in the GEP study are in line with the ratios used in the other studies. The values of kW to MWh savings ratio in the existing studies range from 0.05 to 0.27 kW/MWh, with the median of 0.16 and the average 0.13 kW/MWh. Therefore, we consider GEP’s estimated to be reasonable and use the average “kW savings per MWh savings” to extrapolate MW peak savings in the scenarios of peak load reductions from EE.

[90] *Assessment of All Available Cost-Effective Electric and Gas Savings: Energy Efficiency and CHP*. Submitted to the MA EEAC by Consultants. June 19, 2009 (Draft). Available at http://www.ma-eeac.org/docs/090623-Assessment.pdf.

Table D-2. Achieved Efficiency Savings for Selected Entities' Efficiency Programs[91]

Entity	Annual Savings (%)	Year(s)	Source
Interstate Power & Light (MN)	2.6	2006	Garvey, E. 2007. "Minnesota's Demand Efficiency Program"
Efficiency Vermont (VT)	2.5	2008	Efficiency Vermont 2009. 2008 Highlights
Massachusetts Electric Co. (MA)	2.0	2006	EIA 861
Pacific Gas & Electric (CA)	1.9	2008	CPUC 2009. Energy Efficiency Verification Reports issued on February 5, 2009 and October 15, 2009
Minnesota Power (MN)	1.9	2005	Garvey, E. 2007. "Minnesota's Demand Efficiency Program"
Puget Sound Energy (WA)	1.4	2007	Northwest Power and Conservation Council
Connecticut IOUs (CT)	1.3	2006	CT Energy Conservation Management Board (ECMB). 2007
Pacific Corp (ID & WA)	1.3	2007	Northwest Power and Conservation Council
Energy Trust of Oregon (OR)	1.3	2005	Northwest Power and Conservation Council
Southern California Edison (CA)	1.2	2008	CPUC 2009
Avista Corp (ID, WA, MT)	1.1	2005	Northwest Power and Conservation Council
Idaho Power Co (ID)	1.1	2007	Northwest Power and Conservation Council
San Diego Gas & Electric (CA)	1.1	2008	CPUC 2009
PUD No 1 of Snohomish (WA)	1.0	2007	Northwest Power and Conservation Council
Otter Trail (MN)	0.9	2005	Garvey, E. 2007. "Minnesota's Demand Efficiency Program"
Seattle City Light (WA)	0.9	2007	Northwest Power and Conservation Council
MidAmerican (IA)	0.9	2008	Iowa Utilities Board 2006

We developed another alternative scenario of EE impact, "MISO Best Practices'" scenario, based on states achieving a 2% implementation rate for EE programs. In this scenario, we used the same methodology as the "MISO Current Programs" scenario with the exception of increasing the annual EE acquisition rate to 2.0% (instead of the 1.4 %) in 2020 and holding that 2% rate constant through 2030. After converting the annual energy savings into annual peak load savings by applying our "kW savings per MWh savings" ratio, the 2% annual energy savings from EE translate into an annual 1.89% peak load savings from EE.

This "MISO Best Practices" scenario produces total cumulative savings from EE in 2030 of 29,618 MW and net peak demand of 86,547 MW, which is more than 6,000 MW lower than "MISO Average EE Penetration" scenario net peak demand and more than 18,000 MW lower than "MISO GEP" 2030 net peak demand.

The tables that follow show the details of the savings for each MISO scenario in a year by year format.

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[91] Source: Synapse Energy Economics. May 2010 "Beyond Business as Usual: Investigating a Future without Coal and Nuclear Power in the U.S."

a) MISO Assumptions scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	98,963	99,914	100,864	101,815	102,765	103,716	104,449	105,182	105,916	106,649	107,382	108,184	108,985	109,787	110,588	111,390	112,345	113,300	114,255	115,210	116,165
Annual Savings (% Previous Year Net Peak)	0.52%	1.00%	1.00%	1.00%	1.00%	1.00%	0.86%	0.86%	0.86%	0.86%	0.86%	0.28%	0.28%	0.28%	0.28%	0.28%	0.13%	0.13%	0.13%	0.13%	0.13%
Annual MW Savings	493	944	944	944	944	944	814	814	814	814	814	268	268	268	268	268	122	122	122	122	122
Cumulative MW Savings	493	1,437	2,381	3,325	4,269	5,213	6,027	6,842	7,656	8,471	9,285	9,553	9,821	10,089	10,357	10,625	10,747	10,868	10,990	11,111	11,233
Load - EE (MW)	98,470	98,477	98,483	98,490	98,496	98,503	98,422	98,341	98,259	98,178	98,097	98,631	99,164	99,698	100,231	100,765	101,598	102,432	103,265	104,099	104,932

b) MISO Modified Assumptions scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	98,963	99,914	100,864	101,815	102,765	103,716	104,449	105,182	105,916	106,649	107,382	108,184	108,985	109,787	110,588	111,390	112,345	113,300	114,255	115,210	116,165
Annual Savings (% Previous Year Net Peak)	-	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Annual MW Savings	493	944	944	944	944	944	944	944	944	944	944	944	944	944	944	944	944	944	944	944	944
Cumulative MW Savings	493	1,437	2,381	3,325	4,269	5,213	6,157	7,101	8,045	8,989	9,933	10,877	11,821	12,765	13,709	14,653	15,597	16,541	17,485	18,429	19,373
Load - EE (MW)	98,470	98,477	98,483	98,490	98,496	98,503	98,292	98,081	97,871	97,660	97,449	97,307	97,164	97,022	96,879	96,737	96,748	96,759	96,770	96,781	96,792

c) MISO Current Programs scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	98,963	99,914	100,864	101,815	102,765	103,716	104,449	105,182	105,916	106,649	107,382	108,184	108,985	109,787	110,588	111,390	112,345	113,300	114,255	115,210	116,165
Annual Savings (% Previous Year Net Peak)	-	1.00%	1.00%	1.00%	1.00%	1.00%	0.96%	1.09%	1.16%	1.24%	1.32%	1.32%	1.32%	1.32%	1.32%	1.32%	1.33%	1.33%	1.33%	1.33%	1.33%
Annual MW Savings	493	944	944	944	944	944	947	1,069	1,140	1,210	1,278	1,272	1,268	1,263	1,258	1,253	1,249	1,246	1,244	1,241	1,239
Cumulative MW Savings	493	1,437	2,381	3,325	4,269	5,213	6,160	7,230	8,370	9,580	10,858	12,131	13,398	14,661	15,919	17,172	18,421	19,668	20,911	22,153	23,392
Load - EE (MW)	98,470	98,477	98,483	98,490	98,496	98,503	98,289	97,953	97,546	97,069	96,524	96,053	95,587	95,126	94,669	94,218	93,924	93,632	93,344	93,057	92,773

d) MISO Best Practices Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	98,963	99,914	100,864	101,815	102,765	103,716	104,449	105,182	105,916	106,649	107,382	108,184	108,985	109,787	110,588	111,390	112,345	113,300	114,255	115,210	116,165
Annual Savings (% Previous Year Net Peak)	-	1.00%	1.00%	1.00%	1.00%	1.00%	1.07%	1.31%	1.50%	1.69%	1.88%	1.88%	1.88%	1.88%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.90%
Annual MW Savings	493	944	944	944	944	944	1,058	1,289	1,466	1,638	1,805	1,786	1,768	1,752	1,735	1,719	1,703	1,690	1,678	1,666	1,654
Cumulative MW Savings	493	1,437	2,381	3,325	4,269	5,213	6,271	7,560	9,026	10,664	12,469	14,254	16,023	17,774	19,509	21,228	22,931	24,621	26,299	27,965	29,618
Load - EE (MW)	98,470	98,477	98,483	98,490	98,496	98,503	98,178	97,622	96,890	95,985	94,913	93,929	92,963	92,013	91,079	90,162	89,414	88,679	87,956	87,245	86,547

Appendix C. ISO-NE EE Cases

Every year ISO New England (ISO-NE) develops its long-term ten-year forecast as a part of its Capacity, Energy, Loads and Transmission (CELT) Report, which is then used in the ISO's transmission planning process and annual Regional System Plan (RSP) report. [92]

Currently, ISO-NE uses Forward Capacity Auction (FCA) results to adjust its load forecast for the amounts of Other Demand Resources (ODR) cleared in the corresponding commitment period (up to three years forward).[93] ISO-NE and then assumes that the total amount of ODR available in the following years stays constant at the level of ODR resources cleared in the last FCA prior to the CELT Report completion date. For example, 2010 CELT Report uses the amounts of ODR resources cleared in the FCA 1, FCA 2, and FCA 3 to reduce system load in 2010, 2011, and 2012, and then assumes that there are no additional ODR resources available after 2012, reducing system load by the amount of ODRs cleared in FCA 3 throughout the rest of the forecasting horizon. This approach results in a gradual growth of net peak load through 2030, with an average annual growth rate of 1.34% (the "ISO-NE Assumptions" scenario).

Given the results of EE participation in the last four FCAs, as well as current states' EE goals and achieved EE savings to date, ISO-NE's assumption of no additional EE after the last FCA commitment period leads to an underestimation of the realistic impact of EE on future loads. Instead, we propose two additional scenarios with more realistic levels of EE participation. The first modified scenario, called "ISO-NE Modified Assumptions", is based on a NESCOE proposal for an ISO-NE economic study. The NESCOE proposal uses the amount of EE resources cleared in the first three FCAs as a measure of EE additions in 2010, 2011, and 2012, and then assumes that the three-year average quantity of EE resources added in 2010-2012 (234 MW) will be added annually throughout 2030.

The "ISO-NE Modified Assumptions" scenario implies an average growth rate of EE penetration of 0.82% and results in the average annual peak load growth rate of 0.71%. It produces a 2030 level of peak load of 30,621 MW, which is more than 4,100MW lower than the 2030 level of peak load in the "ISO-NE Assumptions" scenario.

Next, to be consistent with the MISO scenarios, we also created an "ISO-NE Current Programs" scenario, which assumes achieving 1.33% of savings from EE in peak load by 2015. In this scenario, we use the amount of new EE cleared in FCA 1, 267 MW, as a measure of EE resources available in 2010, which constitutes about 1% of 2010 system load, and then we gradually increase the savings rate from 1% in 2010 to 1.33% in 2015 and then fix the annual savings from EE at a constant 1.33% rate for the remainder of the study period.

The "ISO-NE Current Programs" scenario results in a slower growth in annual peak loads through 2030, with an average annual peak load growth rate of 0.28%. In this scenario, the total cumulative amount of EE by 2030 is almost 7,723 MW, which results in 2030 net peak load level of 28,085 MW (more than 2,500 MW lower than 2030 level of net peak load in "ISO-NE Modified

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[92] ISO New England, Aoril 2010. 2010-2019 Forecast Report of Capacity, Energy, Loads, and Transmission. Available at: http://www.iso-ne.com/trans/celt/report/2010/2010_celt_report.pdf; ISO New England, October 28, 2010. 2010 Regional System Plan. Available at: http://www.iso-ne.com/trans/rsp/index.html

[93] ODR include EE, distributed generation, and combined heat and power resources.

Assumptions" scenario, and more than 4,500 MW lower than "ISO-NE Assumptions" net peak load).

As we did for the MISO analysis, we developed a scenario for ISO-NE that assumes a 2 percent annual reduction in energy savings as a more appropriate estimate of EE potential over the long term based on a best practices standard.[94] This 2% annual savings from EE is calculated as a percentage of the previous year's net energy consumption.

We applied the same conversion factor for EE impact on energy to EE impact on load as we developed in the MISO case study. After applying "kW savings per MWh savings" ratio, the 2% annual savings from EE in energy is equivalent to a 1.89% annual savings from EE in peak load.

The "ISO-NE Best Practices" scenario assumes the achievement of a 1.89% annual reduction in peak load by 2015. In this scenario, we use the amount of new EE cleared in FCA 1 (267 MW), as a measure of EE resources available in 2010, which constitutes about 1% of 2010 system load. Next, we use gradually increased the annual savings rate from 1% in 2010 to 1.89% in 2015. We then held the annual savings from EE at a constant 1.89% rate for the remainder of the study period.

In the "ISO-NE Best Practices" scenario net peak load grows until 2012, and then starts decreasing slowly to an almost flat peak load in the range of 25,700-25,900 MW by 2030, which is below 2010 net peak load level of 26,398 MW.

The tables that follow show the details of the savings for each ISO-NE scenario in a year by year format.

[94] This scenario is based on the same reports of achieved EE savings and estimates of achievable future savings that supported the MISO Best Practices scenario. See Table D-2 above.

a) ISO-NE Assumptions Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	27,190	27,660	28,165	28,570	29,025	29,450	29,785	30,110	30,430	30,730	31,160	31,596	32,039	32,487	32,942	33,403	33,871	34,345	34,826	35,314	35,808
Cumulative MW Savings	572	784	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073	1,073
Load - EE (MW)	26,618	26,876	27,092	27,497	27,952	28,377	28,712	29,037	29,357	29,657	30,087	30,523	30,966	31,414	31,869	32,330	32,798	33,272	33,753	34,241	34,735

b) ISO-NE Modified Assumptions Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	27,190	27,660	28,165	28,570	29,025	29,450	29,785	27,190	27,660	28,165	28,570	29,025	29,450	29,785	27,190	27,660	28,165	28,570	29,025	29,450	29,785
Annual MW Savings	267	228	206	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234	234
Cumulative MW Savings	654	890	975	1,209	1,443	1,677	1,911	2,145	2,379	2,613	2,847	3,081	3,315	3,549	3,783	4,017	4,251	4,485	4,719	4,953	5,187
Load - EE (MW)	26,536	26,770	27,190	27,361	27,582	27,773	27,874	27,965	28,051	28,117	28,313	28,515	28,724	28,938	29,159	29,386	29,620	29,860	30,107	30,361	30,621

c) ISO-NE Current Programs Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	27,190	27,660	28,165	28,570	29,025	29,450	29,785	27,190	27,660	28,165	28,570	29,025	29,450	29,785	27,190	27,660	28,165	28,570	29,025	29,450	29,785
Annual Savings (% Previous Year Net Peak)	1.00%	1.06%	1.13%	1.20%	1.26%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%
Annual MW Savings	267	282	302	322	341	361	362	361	361	360	359	360	361	362	364	365	366	367	369	370	372
Cumulative MW Savings	654	936	1,238	1,560	1,901	2,262	2,624	2,985	3,346	3,706	4,065	4,426	4,787	5,150	5,513	5,878	6,244	6,611	6,980	7,351	7,723
Load - EE (MW)	26,536	26,724	26,927	27,010	27,124	27,188	27,161	27,125	27,084	27,024	27,095	27,171	27,252	27,338	27,429	27,525	27,627	27,734	27,846	27,963	28,085

d) ISO-NE Best Practices Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	27,190	27,660	28,165	28,570	29,025	29,450	29,785	27,190	27,660	28,165	28,570	29,025	29,450	29,785	27,190	27,660	28,165	28,570	29,025	29,450	29,785
Annual Savings (% Previous Year Net Peak)	1.00%	1.17%	1.35%	1.53%	1.71%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%
Annual MW Savings	267	312	361	411	459	507	505	502	499	496	492	491	490	489	488	487	487	487	486	486	486
Cumulative MW Savings	654	966	1,327	1,738	2,198	2,705	3,210	3,712	4,211	4,707	5,199	5,689	6,179	6,668	7,156	7,643	8,130	8,616	9,103	9,589	10,075
Load - EE (MW)	26,536	26,694	26,838	26,832	26,827	26,745	26,575	26,398	26,219	26,023	25,962	25,907	25,860	25,820	25,786	25,760	25,741	25,729	25,723	25,725	25,733

Appendix D. PJM EE Cases

PJM develops an annual ten-year load forecast that is then used in the PJM Regional Transmission Expansion Plan (RTEP). The RTEP process produces an annual assessment of the bulk power system that identifies potential reliability issues and discusses planned and proposed bulk power system enhancements.[95]

PJM's current process uses the amounts of EE resources that clear in its annual capacity auctions (for delivery three years forward) to adjust its load forecast for future auctions. PJM assumes that the total amount of EE available in the following years stays constant at the level of EE resources cleared in the last base residual auction (BRA). The BRA for the 2012-13 delivery year was the first auction that allowed participation of EE resources on an equal basis with all other generation and demand resources. To date, there have been two auctions with EE resources participating: the BRA for the 2012-13 commitment period cleared 568.9 MW and the BRA for the 2013-14 commitment period cleared 679.4 MW of EE, which included 110.5 MW of new resources. Since base residual auctions clear generation and demand-side resources three-years forward, we assume that 568.9 MW of EE available in 2012 are installed gradually throughout a three year period, 2010-2012, with 189.63 MW annual increments. PJM assumes that the amount of EE available stays fixed at 679.4MW from 2013 forward. This approach results in the growth of net peak load through 2030 at an average annual growth rate of 1.58%.

Given the results of EE participation in the last two BRAs, as well as current states' EE goals and achieved EE savings to date, we believe that PJM's assumption of no additional EE after the last BRA commitment period—the "PJM Assumptions" scenario—severely underestimates impact of EE on load forecast. We propose three additional scenarios which represent more realistic levels of EE penetration.

The first modified scenario, called "PJM Modified Assumptions" uses the same 2010 value of EE as "PJM Assumptions" scenario, then applies gradual annual increases in the savings rate to 1% of peak load savings by 2020 and then fixes the annual savings from EE at a constant 1% for peak load rate for the remainder of the study period. The "PJM Modified Assumptions" scenario results in a slower but still increasing net peak load, with an average annual net peak load growth rate of 0.88%. It produces a 2030 net peak load of 153,440 MW, which is about 23,000 MW lower than the 2030 level of peak load in the "PJM Assumptions" scenario.

Next, we modeled "PJM Current Programs" scenario based on the same studies that we relied on for the "MISO Current Programs" and the "ISO-NE Current Programs" scenarios.[96] The 'PJM Current Programs" scenario uses the same 2010 value of EE as "PJM Assumptions" and "PJM Modified Assumptions" scenarios, then applies gradual annual increases in the savings rate to 1.4% energy savings, or corresponding 1.33% of peak load savings, in 2020 and then uses a fixed annual savings rate from EE of 1.4% for energy (1.33% for peak load) for the remainder of the study period. The "PJM Current Programs" scenario results in significantly higher 2030 cumulative peak load savings from EE of 30,250 MW, compared to 3,567 MW in the "PJM Modified Assumptions" and only 679 MW in "PJM Assumptions" scenarios. These cumulative

[95] PJM 2009 Regional Transmission Expansion Plan. Available at: http://www.pjm.com/documents/reports/~/media/documents/reports/2009-rtep/2009-rtep-report.ashx

[96] See Table D-2 above.

savings from EE result in substantial reduction of 2030 net peak load to 146,706 MW from the 176,277 MW PJM 2030 net peak load.

Consistent with the approach we used for MISO and ISO-NE, we developed an additional scenario that reflects the same best practices goal that we used for MISO and ISO-NE. Given nationwide achieved EE savings up to date and states energy efficiency goals, we again used a 2% annual energy savings from EE, or equivalently 1.89% annual peak load savings form EE, as a more appropriate estimate of EE potential over the long term.[97] This estimate resulted in the "PJM Best Practices" scenario.

The "PJM Best Practices" scenario, is very similar to the "PJM Current Programs" scenario, but the EE annual reduction to peak load increases gradually to 1.89% by 2020, and then stays at a fixed 1.89% level throughout 2030. In the "PJM Best Practices" scenario net peak load grows throughout 2015, then decreases slightly for the next 4-5 years and then stays relatively flat around 135,000 MW,900 MW by 2030, which is still higher that 2010 net peak load level of 128,912 MW, but substantially lower (by about 40,000 MW) than "PJM Assumptions" or "PJM Modified Assumptions" scenarios.

The tables that follow show the details of the savings for each PJM scenario in a year by year format.

[97] See Table D-2 above.

a) PJM Assumptions Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	129,102	132,736	137,025	140,029	142,104	143,913	145,377	146,837	148,168	149,609	150,983	153,399	155,853	158,347	160,880	163,454	166,070	168,727	171,426	174,169	176,956
Cumulative MW Savings	189.6	379.3	568.9	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4	679.4
Load – EE (MW)	128,912	132,357	136,456	139,350	141,425	143,234	144,698	146,158	147,489	148,930	150,304	152,719	155,174	157,667	160,201	162,775	165,390	168,047	170,747	173,490	176,277

b) PJM Modified Assumptions Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	129,102	132,736	137,025	140,029	142,104	143,913	145,377	146,837	148,168	149,609	150,983	153,399	155,853	158,347	160,880	163,454	166,070	168,727	171,426	174,169	176,956
Annual Savings (% Previous Year Net Peak)	0.15%	0.23%	0.32%	0.40%	0.49%	0.57%	0.66%	0.74%	0.83%	0.91%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
Annual MW Savings	190	299	420	548	676	803	929	1,053	1,177	1,300	1,422	1,422	1,432	1,442	1,452	1,463	1,474	1,486	1,497	1,509	1,522
Cumulative MW Savings	190	489	909	1,457	2,134	2,936	3,865	4,918	6,095	7,394	8,817	10,238	11,670	13,112	14,564	16,027	17,501	18,987	20,485	21,994	23,516
Load – EE (MW)	128,912	132,247	136,116	138,572	139,970	140,977	141,512	141,919	142,073	142,215	142,166	143,160	144,183	145,235	146,316	147,427	148,568	149,740	150,942	152,175	153,440

c) PJM Current Programs Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	129,102	132,736	137,025	140,029	142,104	143,913	145,377	146,837	148,168	149,609	150,983	153,399	155,853	158,347	160,880	163,454	166,070	168,727	171,426	174,169	176,956
Annual Savings (% Previous Year Net Peak)	0.15%	0.27%	0.38%	0.50%	0.62%	0.74%	0.86%	0.98%	1.09%	1.21%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%
Annual MW Savings	190	342	507	682	858	1,030	1,202	1,371	1,538	1,702	1,864	1,858	1,865	1,873	1,881	1,890	1,899	1,909	1,919	1,929	1,940
Cumulative MW Savings	190	532	1,039	1,721	2,579	3,609	4,811	6,182	7,720	9,421	11,286	13,144	15,009	16,882	18,764	20,654	22,553	24,462	26,381	28,310	30,250
Load – EE (MW)	128,912	132,204	135,986	138,308	139,525	140,304	140,566	140,655	140,448	140,188	139,697	140,255	140,844	141,464	142,116	142,800	143,516	144,265	145,046	145,859	146,706

d) PJM Best Practices Scenario

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Peak Demand (MW)	129,102	132,736	137,025	140,029	142,104	143,913	145,377	146,837	148,168	149,609	150,983	153,399	155,853	158,347	160,880	163,454	166,070	168,727	171,426	174,169	176,956
Annual Savings (% Previous Year Net Peak)	0.15%	0.32%	0.50%	0.67%	0.84%	1.02%	1.19%	1.37%	1.54%	1.72%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%	1.89%
Annual MW Savings	190	414	655	909	1,164	1,413	1,660	1,900	2,135	2,363	2,586	2,563	2,560	2,558	2,557	2,556	2,557	2,558	2,560	2,562	2,566
Cumulative MW Savings	190	604	1,258	2,168	3,332	4,745	6,405	8,305	10,440	12,803	15,389	17,951	20,511	23,069	25,626	28,182	30,739	33,297	35,856	38,419	40,984
Load - EE (MW)	128,912	132,132	135,767	137,861	138,772	139,168	138,972	138,532	137,728	136,806	135,594	135,447	135,342	135,278	135,254	135,272	135,331	135,430	135,570	135,751	135,972