2011 Northeast Coordinated System Plan

ISO New England, New York ISO and PJM

Final

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Preface

This report is a compilation of summaries of activities that have been completed or are currently ongoing with the Joint ISO/RTO Planning Committee (JIPC) during the years 2010 and 2011. The report also includes discussion of the Northeast Power Coordinating Council (NPCC), the Reliability*First* Corporation (RFC), and the North American Electric Reliability Corporation (NERC).

1 Executive Summary

ISO New England Inc. (ISO-NE), the New York Independent System Operator (NYISO), and the PJM Interconnection (PJM) each produce their own annual regional plan covering the needs of the region that each ISO/RTO serves. In addition, these ISO/RTOs work jointly under a formal protocol studying numerous issues related to interregional electric system problems, developments and performance. The intent of collaboration under the joint planning protocol is to ensure that the electric system is planned on a wider interregional basis, and that this planning is proactive and well coordinated. This report covers the current joint activities and their status as well as planned activities to be conducted under the protocol.

ISO-NE, NYISO, and PJM follow a planning protocol to enhance the coordination of planning activities and address planning seams issues among the interregional balancing authority areas.[1] Hydro-Québec TransÉnergie, the Independent Electric System Operator (IESO) of Ontario and the New Brunswick System Operator (NBSO) participate on a limited basis to share data and information. The key elements of the protocol are to establish procedures that accomplish the following tasks:

- Exchange data and information to ensure the proper coordination of databases and planning models for both individual and joint planning activities conducted by all parties
- Coordinate interconnection requests likely to have cross-border impacts
- Analyze firm transmission service requests likely to have cross-border impacts
- Develop the Northeast Coordinated System Plan (NCSP) on a periodic basis[2]
- Allocate the costs associated with projects having cross-border impacts consistent with each party's tariff and applicable federal or provincial regulatory policy

To implement the protocol, the Joint ISO/RTO Planning Committee (JIPC) was formed, and an open stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) was created to discuss work conducted by the JIPC.[3] The IPSAC provides input to the JIPC on study scopes of work, assumptions, results, and reports. Through the open stakeholder process, the JIPC has made progress addressing several interregional balancing authority area issues.

The 2009 NCSP (NCSP09) summarized several studies performed by the JIPC.[4] These included analysis of transmission and generation facilities affecting interregional system performance, such as major 500 kV and 765 kV expansion plans in PJM, new ties between NYISO and the neighboring PJM and ISO-NE systems, planning evaluations of the loss of source limit for New England, and other joint interregional analyses and updates. The JIPC also conducted studies to investigate concerns regarding potential generation deliverability and load deliverability issues near the PJM/NYISO border and market efficiency analyses performed with focuses on the NYISO/PJM and the NYISO/ISO-NE border areas.

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[1] Additional information about the Northeastern ISO/RTO Planning Coordination Protocol ("Protocol") is available online at http://www.interiso.com/public/document/Northeastern%20ISO-RTO%20Planning%20Protocol.pdf. An RTO is a Regional Transmission Organization that has operational control of the transmission system for a wide geographic area. ISO New England is the RTO for Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. The New York Independent System Operator (NYISO) is responsible for New York State. The PJM Interconnection is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
[2] Past NCSP reports and related materials are available at http://www.interiso.com/documents.cfm. While "periodic" is not explicitly defined within the protocol, new analytical material has historically been provided on an annual basis.
[3] See "Inter-ISO Planning," IPSAC meeting notices: http://www.interiso.com/default.cfm
[4] See NCSP09: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/2010/ncsp09final.pdf

This 2011 NCSP (NCSP11) builds upon the NCSP09 report and summarizes several interregional studies and issues which were addressed. Since the issuance of NCSP09, two additional JIPC reports were posted documenting subsequent studies and can be referenced as addenda to the information presented herein.[5] Key issues summarized in this NCSP11 report include the following:

- Market efficiency analyses, including the development of coordinated production cost models of the three ISO/RTOs and neighboring regions. These joint production cost analyses will serve as guidance for future interregional transmission studies.
- The effects of environmental regulations, including the integration of wind and other renewable resources
- Fuel diversity issues, including the current and future dependency upon natural gas.
- The effect of demand side resources and how they are reflected by each of the ISO/RTOs in their respective system operations and planning.
- Coordinated tracking and discussion of the Federal Energy Regulatory Commission (FERC) Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation, which became a Final Rule (FERC Order 1000) in 2011.

Interregional planning starts with the individual regional plans developed by the three ISO/RTOs through their open stakeholder processes. These plans address resource adequacy needs, discuss the development of transmission upgrades and new generation interconnections, and include other planning issues. The ISO//RTOs also conduct economic studies that assist policy makers and transmission developers. The regional plans are coordinated with neighboring systems. (Section 3)

Each regional plan is coordinated with neighboring systems, as demonstrated by studies of transmission and generation facilities affecting interregional system performance. Additionally, the JIPC has conducted market efficiency analyses focusing on the NYISO/PJM and the NYISO/ISO-NE border areas. While market efficiency analysis is ongoing, significant progress has been made in the coordination of the joint production cost database. Examination of the high level results produced to date has demonstrated that they are consistent with current market conditions. (Section 4)

There are several other interregional planning activities supported by the ISO/RTOs that are shared and discussed by the JIPC. These include studies coordinated by Reliability Councils, the North American Electric Reliability Corporation (NERC), and the ISO/RTO Council (IRC). Interconnection-wide analysis is also being addressed by the Eastern Interconnection Planning Collaborative (EIPC). Fuel diversity and natural gas issues, and their impact on the electric system, have been coordinated among the ISO/RTOs throughout the Northeast. These ongoing efforts will be of increasing importance due to the combined impacts of upcoming environmental regulations and anticipated low natural gas prices, which will likely lead to increased natural gas reliance within the overall PJM/NYISO/ISO-NE area. (Section 5)

The northeastern states are subject to many environmental regulations, including ozone standards, green house gas (such as carbon dioxide) restrictions, and use of cooling water. The regulations have the potential to affect generator economic performance by increasing costs for emission allowances, new controls, and cleaner fuels. The regulations may also affect reliability by limiting generator energy production, reducing capacity output, or contributing to unit retirements. Because interregional system performance could change as a result of new generation patterns, the JIPC monitors environmental regulations for potential system impacts. (Section 6)

[5] See the June 2011 Joint Report on the Impact of Environmental and Renewable Technology Issues in the Northeast, available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/reports/2011/env_renewable_report.pdf, and the June 2011 New York/New England Economic Study Process Report and Illustrative Results, available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/reports/2011/ny_ne_eco_study.pdf

Most of the states served by PJM, NYISO, and ISO-NE have renewable portfolio standards or related energy policies. The queue for renewable resource development in the three ISO/RTO regions totals more than 48 gigawatts (GW), over 81% of which is wind resources, including a significant amount of offshore wind capacity. There are also a growing number of solar projects, which comprise 7% of renewable project capacity in the three queues. These projects, if developed, would be sufficient to meet the RPS short term goals while recognizing that contributions could come from other RPS sources not in the queues. Many of the RPSs can be met by a combination of renewable generation, energy efficiency, behind the meter generation, and alternative compliance payments that also serve as a cap on the price paid for renewable energy. (Section 7)

The growth of wind resources creates system integration and operating challenges for all three ISO/RTOs. These include transmission development to interconnect these wind projects, system operating flexibility to accommodate wind‘s variability, operator awareness and practices, and the need for wind generator plant performance standards. The JIPC monitors the separate evaluations of wind issues being conducted individually by the three ISO/RTOs, the Department of Energy (DOE), and the NERC (Section 8). Many of the Northeastern states are also promoting demand resources and their use is reflected in each of the ISO/RTOs planning processes and wholesale markets, including efforts to integrate energy efficiency into long-term ISO/RTO planning. (Section 9)

FERC's Order 1000, issued on July 21, 2011, is the Final Rule in Docket RM10-23-000 which sets forth additional requirements to build on Order 890. These additional requirements include regional and interregional planning procedures and cost allocation, and the incorporation of "public policy considerations" into the planning process. The Northeast ISO/RTOs' existing regional reliability and economic planning processes, including cost allocation, are already largely compliant with the requirements of Order 1000. While the ISO/RTOs already include some consideration of public policies in their planning process, there will likely be some tariff modifications needed to comply with the Final Rule. The Northeast Planning Protocol already contains many of the inter-regional planning elements now required under Order 1000. While the Final Rule does not require a multi-regional planning process, the Northeast ISO/RTOs plan to leverage the existing Northeast ISO/RTO Planning Coordination Protocol to address the inter-regional planning and cost allocation requirements of the Final Rule. Compliance filings on the regional requirements are due on October 11, 2012 and the inter-regional requirements are due on April 11, 2013. (Section 10)

Planning is subject to many uncertainties, revised forecasts, and applications of new technologies. Because planning is continuous, the results and activities discussed in NCSP represent a snapshot in time. The JIPC will continue sharing and coordinating planning issues and efforts across ISO/RTO boundaries and remain alert to changes in system conditions and forecasts. The use of new technologies will be considered as a factor that may affect future transmission development within and across the three ISO/RTO territories, and the JIPC will continue to serve as a body to discuss these developments.

Interregional studies are increasing in importance and the need for studies of the future system is vital. In addition to the JIPC, the three ISO/RTOs participate in other interregional study groups that support the Northeast Power Coordinating Council (NPCC), the Reliability*First* Corporation (RFC), the NERC, and the IRC. For the Northeast, the three ISO/RTOs will continue and expand planning activities that address the mutual interactions of the planned high voltage transmission systems of all regions, with particular emphasis on major planned transmission system additions and future system power transfer capabilities. The three ISO/RTOs also remain committed to the IPSAC open stakeholder process as a forum to discuss interregional planning activities.

2 Introduction

The New York Independent System Operator (NYISO), ISO New England (ISO-NE) and the PJM Interconnection actively coordinate system planning. In the fall of 2003, the three ISOs/RTOs recognized that a broader initiative including other transmission operators in the Northeast would be beneficial and accordingly, in January 2003, an inter-area Transmission Coordination Task Force (TCFT) was formed including ISO-NE, NYISO, PJM, and the Canadian members of Northeast Power Coordinating Council (NPCC). NPCC staff also participated in these discussions. This led to the development of a protocol for coordinating these planning activities that was formalized in December 2004. The Joint Interregional Planning Committee (JIPC) carries out the coordinated planning of the combined ISO-NE, NYISO and PJM systems and the Interregional Planning Stakeholder Advisory Committee (IPSAC) provides useful public input to the planning process and its activities.

While not parties to the protocol, the Independent Electricity System Operator of Ontario (IESO), Hydro-Québec TransÉnergie (HQ), and New Brunswick Power (NB Power) agreed to participate on a limited basis in the data-sharing and information-exchange process. They also participate in interregional planning studies for projects that may have inter-area impact, to ensure better coordination in the development of the power system. Planning activities are conducted in close coordination with the Northeast Power Coordinating Council (NPCC) and the Reliability First Corporation (RFC).

To report periodically on these interregional planning activities, a Northeast Coordinated System Plan (NCSP) describes these activities and their progress. The last NCSP was produced in 2009. Since then, periodic updates have been provided to the IPSAC.[6] This document is an update on some of these interregional activities occurring since the previous NCSP report was issued in May 2010.

This report is organized as follows: Section 3 provides summaries of the ISO/RTO's annual regional plans. Section 4 summarizes the interregional studies conducted by the JIPC. Section 5 covers additional coordinated planning activities and issues, including fuel diversity issues. Section 6 covers key environmental issues with potential interregional impacts. Section 7 summarizes renewable portfolio standards. Section 8 summarizes wind and renewable resource studies. Section 9 discusses demand resource issues, Section 10 gives an overview of FERC Order 1000, and Section 11 describes plans for additional interregional studies. Finally, Section 12 presents a report summary and conclusions and Section 13 contains a matrix that provides additional information on the existing transmission cost allocation methods for all the ISO/RTOs and a list of reference materials.

The planning studies discussed in this report are based on 2011 load forecasts and other projected system conditions.

3 Summary of RTO System Plans

Interregional planning starts with the individual regional plans developed by the three ISO/RTOs through their open stakeholder process. Because the planning processes are continuous, interested stakeholders are encouraged to participate in each of the ISO/RTO planning meetings to obtain the most up-to-date information. This section summarizes the individual ISO/RTO plans for 2011. These plans address resource adequacy needs, discuss the development of transmission upgrades and new generation interconnections, and include other planning issues. The ISO/RTOs also conduct economic studies that

[6] Since issuance of NCSP09 a total of six IPSAC meeting were held on the following dates: February 2, 2010, April 30, 2010, October 29, 2010, March 30, 2011, June 27, 2011, and November 29, 2011. Meeting materials are available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/index.html

assist policy makers and transmission developers. Each of the ISO/RTOs continuously strives to improve their planning processes that will include compliance with Order 1000.

3.1 PJM 2011 Regional Transmission Expansion Plan (RTEP)

The PJM Regional Transmission Expansion Plan (RTEP) is published annually in February. The 2011 RTEP describes analysis performed over a range of study years and system conditions, including studies of a 2016 summer peak model. The load forecast used represents all Transmission Owners in the PJM system as of January 1, 2012, and includes a weather normalized summer peak demand forecast, which has a load growth rate of 1.3% annually over the next 10 years, from 154,383 MW in 2011 to 176,060 MW in 2021, an increase of 21,667 MW over the decade. Individual geographic zone growth rates vary from 0.6% to 2.1%. This forecast represents the projection of "unrestricted"[7] peak load growth. Energy Efficiency and Demand Response as well as load diversity is accounted for separately and appropriately factored into the various planning analyses. In developing the RTEP, PJM performs comprehensive power flow, short circuit, stability and market efficiency analyses. These studies assess the impacts of forecast firm loads and transactions with neighboring systems, existing generation and transmission assets, and anticipated new generation and transmission facilities. The PJM Board of Directors (BOD) has authorized more than $18 billion of transmission upgrades and additions since the first Board approved projects in 2000. $5.7 billion of these upgrades are under construction or already in service. This figure includes more than $2 billion that were approved in 2011 alone. Approximately $5.3 billion is for additional transmission upgrades that will maintain reliability for nearly 50,000 megawatts (MW) of new generating capacity resources and merchant transmission projects. The 2011 RTEP studies included all previously approved PJM backbone transmission projects. These include: the 2006 approved 502 Junction- Loudoun 500 kV transmission line (TRAIL), the 2007 approved Susquehanna-Lackawanna-Jefferson-Roseland 500 kV circuit and the 2006 approved Carson-Suffolk circuit. In addition to the backbone projects, RTEP included the 500 kV Jacks Mountain dynamic reactive project in western Pennsylvania. The Amos-Kemptown 765 kV circuit (PATH) and the Possum Point-Calvert Cliffs-Indian River-Salem 500 kV Circuit-Mid Atlantic Power Pathway (MAPP) are not included in the 2011 RTEP analysis because the need for these facilities is continuing to be reexamined as part of the 2012 RTEP. The many other upgrades across PJM are discussed in more detail in the 2011 RTEP and on the Planning/RTEP pages of the PJM website.[8] All PJM backbone projects continue to be evaluated annually and as changing system conditions warrant.

PJM continuously addresses the need for improvements to planning processes based on its own initiative as well as comments and suggestions by stakeholders. These on-going efforts include the recent federal requirements of FERC Order No. 1000. During 2012 PJM will be considering significant enhancements to the PJM planning process including how to improve planning under conditions involving uncertain and changing assumptions and how to address public policy interactions as well as potential projects that satisfy multiple drivers. This is expected to impact how PJM conducts both Regional and Interregional Planning.

3.2 NYISO 2010 Comprehensive Reliability Plan

The 2010 Reliability Needs Assessment (RNA) found that the planned New York State Bulk Power System (BPS), as studied in the base case, meets applicable Reliability Criteria consistent with NERC, NPCC, and NYSRC requirements. Therefore, the 2010 Comprehensive Reliability Plan (CRP), published

[7] The unrestricted peak reflects peak load growth prior to any reduction for load management, accelerated energy efficiency or voltage reduction.
[8] RTEP Upgrades located at: [RTEP Upgrades located at: http://pjm.com/planning/rtep-upgrades-status.aspx](http://pjm.com/planning/rtep-upgrades-status.aspx)

January 11, 2011,[9] did not include requests for market based and regulatory solutions and no such solutions were evaluated for this plan. There are three primary reasons the 2010 RNA continues to find no reliability needs for the next 10 years:

1. **Generation additions** – Two new proposed generating plants totaling 1,060 MW located in Zone J were included in the 2010 RNA Base Case, but were not included in the previous RNAs.

2. **Lower Energy Forecast –** two factors contributed to this outcome:

   The 2009 Recession – The effect of the 2009 recession was to reduce the peak demand forecast for 2011 by 1,400 MW, before any energy efficiency adjustments. This also reduced the projections of peak load in subsequent years.

   Statewide Energy Efficiency Programs (15 x 15) – This refers to the New York State Governor's initiative to lower energy consumption on the electric system by 15% of the 2007 forecasted levels in 2015. Based on seven factors set forth in the 2010 RNA, the projected impact of these energy efficiency programs increased from the 2009 RNA. The 2009 RNA included cumulative energy savings of 10,235 GWh by 2018. In the 2010 RNA, this value increased to 13,040 GWh by the year 2018 and to 13,684 GWh by the year 2020.

   The 2010 RNA Base Case forecast reflected larger energy efficiency usage reductions than the preceding 2009 RNA Base Case forecast. Each of those base case forecasts was created by subtracting a projected energy efficiency impact from the respective current econometric forecast. For example, in the case of the 2009 RNA Base Case energy forecast for 2015, a projected 8,086 GWh in energy savings were subtracted from the econometric forecast to reach the base case forecast. In the 2010 RNA, for the year 2015, a projected 9,914 GWh were subtracted from the current econometric forecast.

3. **Increased registration in Special Case Resource (SCR)** – The NYISO continues to experience increases in the registration of the SCR[10] programs that supply capacity resources to the system through the NYISO market. The NYISO projected registrations of 2,251 MW of SCRs, an increase of 167 MW of resources over the SCR levels included in the 2009 RNA Report.

3.3 ISO New England 2011 Regional System Plan

ISO-NE's 2011 Regional System Plan (RSP) was published on October 21, 2011. The major findings of the report include the following:

- Capacity—The results of the latest Forward Capacity Auction (FCA #5) show that New England should have adequate resources to meet demand through 2014/2015. Future FCA auctions will

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[9] Available at: http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/CRP_2010_FINAL_REPORT_January_11__2011.pdf

[10] SCRs are end-use Loads capable of being reduced upon demand and distributed generators that are not visible to the NYISO's Market Information System.

help procure the capacity needed, should generation retirements occur after the 2014/2015 timeframe.

- Demand forecast—Energy consumption is projected to grow an average 1.1% annually over the next 10 years, while summer peak demand is expected to grow by 1.4% per year.
- Transmission upgrades—Transmission upgrades have been identified in all six New England states to meet reliability requirements. Several are currently under construction, have been approved in state-level siting proceedings, or are being prepared for siting. These include the Maine Power Reliability Program, upgrades in Southeastern Massachusetts, and the Interstate Reliability Project in Connecticut, Massachusetts and Rhode Island. In all, more than 189 projects, representing an investment of about $5.3 billion, have been proposed to reinforce the reliability of New England's power system.
- Transmission—Eight major 345 kilovolt transmission upgrades required for power system reliability have been completed in the region, and construction has begun on several more. From 2002 to the end of 2011, a total of 397 transmission projects were put into service, representing a $4.8 billion infrastructure investment in all six states. These transmission upgrades maintain system reliability and support market efficiency and have resulted in significant reductions in congestion costs.
- Generation—Competitive wholesale markets have encouraged the construction of more than 13,100 megawatts (MW) of new generation in the region since 1997.
- Demand resources—The Forward Capacity Market has encouraged expansion of demand-side resources, such as energy efficiency and active demand resources, which reduce load only when needed. More than 2,000 MW of demand resources are available in 2011 and more is being planned.
- Renewable Portfolio Standards and related policies—Renewable Portfolio Standards and related goals call for renewable resources and energy efficiency to comprise 31.2% of New England's total projected energy use by 2020, with state energy-efficiency and combined heat and power programs making up about 13.6% of projected energy use.
- Fuel diversity—New England's dependency on natural gas is expected to continue to increase. In 2000, natural gas-fired power plants produced about 15% of the region's electricity. By 2010, that had increased to 45.6%. At the same time, electric energy produced by oil units declined from 22% in 2000 to 0.4% in 2010.
- Environmental regulations—Impending changes to federal air and water regulations are likely to affect some New England generators. The ISO has initiated a study to better quantify the resource implications of existing and upcoming EPA regulations and will continue to monitor how federal and state policy changes may affect the region.
- Environmental performance—Emission rates for New England generators continue to decline. Compared with 1999, the 2009 average emission rate for sulfur dioxide (SO_2) has declined by 71%, nitrogen oxides (NO_X) by 66%, and carbon dioxide (CO_2) by 18%.

The following major initiatives are aimed at planning for the future grid in the region and are also discussed in the 2011 RSP report:

- Strategic Planning Initiative—ISO New England, working closely with its stakeholders, has identified five challenges expected to have an impact on the New England power system in the coming years. The challenges include resource performance and flexibility; increased reliance on natural gas; retirement of generators; integration of variable resources; and alignment of planning and markets. The Strategic Planning Initiative will proactively address these issues to ensure continued reliability and an efficient marketplace in the long term.[11]

[11] Meeting materials, notes and meeting dates for discussing the Strategic Planning Initiative are available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/index.html.

- Economic planning studies—ISO has completed a number of economic studies that address future system performance for various scenarios. Completed studies and follow-up analyses are being conducted to show the effects of generator retirements, the integration of wind generation, and interregional transfers with neighboring power systems, such as New York ISO, PJM Interconnection, and the Canadian regions. (See Section 3.4.3)
- Energy efficiency forecasting—ISO New England is currently developing a methodology to forecast long-term energy-efficiency savings from state-sponsored programs, for years beyond what is currently captured in the Forward Capacity Market.
- Market resource alternatives—Regional System Plans have provided considerable information on the amounts, types, locations, and performance requirements of resources that could meet system needs. In response to stakeholder requests for more detailed information, the ISO recently conducted a pilot study analyzing how various market resources could solve reliability needs in Vermont and New Hampshire. The ISO intends to conduct more such analyses for other areas in the region.

3.4 Summaries of RTOs' Economic Studies

As one of the principles outlined for planning in Order 890,[12] each of the ISO/RTOs is required to conduct an open and transparent transmission planning process that incorporates market responses into the assessments of system needs. Aspects of each ISO/RTO's planning process, including planning methods that consider the use of demand-side resources, have been implemented as part of compliance with FERC Order 890. The economic planning studies that are required under each ISO/RTO's OATTs provide stakeholders with information on the economic and environmental performance of the system under various system conditions and expansion scenarios.

3.4.1 PJM Economic Studies

PJM's annual RTEP review includes a market efficiency analysis following the completion of the near-term reliability plan for the region. PJM's market efficiency planning analyses are based on the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input assumptions used in the projection of future market inefficiencies include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements, and expected levels of demand response. PJM inputs its study assumptions into a commercially available market simulation model that is available for license by all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load.

The metrics of economic inefficiency include historic and projected congestion. The measures of historic congestion are gross congestion, unhedgeable congestion, and pro-ration revenues distributed to Auction Revenue Right holders. The measure of projected congestion is based on a market analysis of future system conditions. This market analysis results in future projections of the congestion and its binding constraint drivers. These congestion measures for binding constraints are posted and available to stakeholders and form the basis for PJM and stakeholder development of remedies. Transmission plans from the reliability analysis or new plans presented that economically relieve historical or projected congestion are candidates for market efficiency solutions. The successful candidates are those facilities that pass PJM's FERC-approved threshold test and bright line economic efficiency test. The PJM bright line test is a cost-benefit metric that ensures only projects with sufficient stakeholder benefit proceed.

[12] Order 890 requires that ISO/RTOs comply with 9 planning principles. A summary of these, and their impact, is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/may162007/pto%27s_summary_of_local_planning_requirements_under_order_no._890.pdf

Project benefits include recognition of a project's energy market benefit including production costs and load energy payments.

PJM's 2011 market efficiency analysis consisted of benchmark analysis, a near-term simulation and a long-term simulation. A benchmark analysis was conducted to compare 2011 actual congestion to simulated congestion results. The benchmark analysis showed that simulated results of approximately $1.4 billion were comparable to the actual day-ahead congestion costs of $1.24 billion. The starting assumptions and results of PJM's market efficiency analysis are available at: http://pjm.com/documents/reports/rtep-report.aspx.

3.4.1.1 Near-Term Simulations

Near-term simulations studied congestion levels in 2011 and 2014 in order to assess the economic impact of upgrades identified up through and including those identified as part of the 2010 RTEP cycle. Results indicate approved RTEP upgrades would reduce PJM constrained operations and congestion costs would decrease by approximately 15%.

Simulations using the 2011 transmission topology, generation, and loads identified nearly $800 million of congestion costs. Using the same generation and loads and a 2015 topology resulted in nearly $650 million in congestion, approximately a $150 million reduction. Simulations using 2014 generation and loads and the 2011 transmission topology identified nearly $1.3 billion of congestion costs. Upgrading topology to the 2015 representation resulted in approximately $1.2 billion in congestion costs, approximately a $100 million reduction. Comparisons of the two 2015 RTEP transmission topology simulations shows congestion increases of more than 50% from 2011 to 2014. Several factors appear to be driving this increase, including load growth, the 2011 projections of higher gas prices relative to coal prices, and generation additions primarily in the western part of the PJM system. The simulations also showed that congestion reductions in 2011 and 2014 were attributable to transmission topology differences while other input assumptions remained constant. Major backbone upgrades were responsible for the 15% reduction.

3.4.1.2 Long-Term Simulations

To identify future transmission system bottlenecks, market simulations were conducted for study years 2017 and 2020 using the 2015 RTEP transmission topology. The simulation results indicate congestion costs decrease between the 2017 ($1.47 billion) and 2020 ($1.42 billion) study years due to the addition of new generation in the eastern portion of PJM. Roughly two-thirds of the identified congestion in each study year was associated with the 500 kV reactive interface limits. A significant level of congestion also occurs throughout the study years on the Cloverdale – Lexington 500 kV line which spans the border between the American Electric Power and Dominion Virginia Power transmission zones.

Several stakeholders have proposed upgrades to relieve congestion on these facilities. The upgrade of the Cloverdale – Lexington 500 kV line is projected to provide a reduction of up to 90% in congestion costs in the facility depending on the scope of the upgrade. The project is an approved RTEP project for reliability purposes and has an expected 2017 in-service date.

PJM's 2011 RTEP Plan is available online at: http://pjm.com/documents/reports/rtep-report.aspx.

3.4.2 NYISO Economic Studies

In response to FERC Order No. 890, the NYISO has implemented a planning process pursuant to Attachment Y of its Open Access Transmission Tariff (OATT) to assess both historic and projected congestion on the New York bulk power system. This process, known as the Congestion Assessment and

Resource Integration Study (CARIS), estimates the economic benefits of relieving that congestion with potential system upgrades. The CARIS process builds on the NYISO's Comprehensive Reliability Planning Process (CRPP). Together with the Local Transmission Planning Process (LTPP) and the CRPP, the CARIS completes the NYISO's biennial Comprehensive System Planning Process (CSPP).

In Phase 1 of the CARIS process, the NYISO, in collaboration with market participants, identifies the most congested transmission elements in the New York bulk power system and determines the scope of three studies. In identifying the most congested transmission elements, the NYISO performs both a five-year historic and a ten-year forward-looking congestion assessment and develops potential groupings and rankings based on the highest production cost savings resulting from the relaxation of the transmission constraints. The top three ranked transmission pathways become the subjects of the three CARIS studies. For each of these three studies the NYISO conducts a benefit/cost analysis of integrating potential generic transmission, generation and demand response resources as solutions to the congestion. The primary measurement of the benefit to relieving congestion is production cost savings. In addition to the statewide production cost savings for each generic solution, the NYISO also provided, for informational purposes, additional metrics results for each of the three studies and each of the generic solutions in terms of changes in: (a) emission quantities and costs, (b) New York State generator payments, (c) load payments, (d) installed capacity (ICAP) costs, (e) loss payments for losses on the transmission system, and (f) congestion rents or transmission congestion contracts (TCC) payments.

Developers may propose economic transmission projects for regulated cost recovery under the NYISO's Tariff and proceed through the Project Phase, CARIS Phase 2, which will be conducted by the NYISO upon request and payment by a developer. Developers of all other projects can request that the NYISO conduct an additional CARIS analysis at the developer's cost to be used for the developer's purposes. For a transmission project, the NYISO will determine whether it qualifies for regulated cost recovery under the Tariff. Under CARIS, to be eligible for regulated cost recovery, an economic transmission project must have production cost savings greater than the project cost (expressed as having a benefit to cost ratio (B/C) greater than1.0), a cost of at least $25 million, and be approved by at least 80% of the weighted vote cast by New York's Load Serving Entities (LSEs) that serve loads in zones that the NYISO identifies as beneficiaries of the transmission project.

The 2011 CARIS Phase 1 report presents an assessment of historic (2006-2010) and projected (2011-2020) congestion on the New York State bulk power transmission system and provides an analysis of the potential costs and benefits of relieving that congestion using generic projects as solutions. Consistent with the CARIS procedures, the NYISO ranked and grouped transmission elements with the largest production cost savings when congestion on that constraint was relieved. Based on the top three groupings, three studies were selected: Central East - New Scotland - Pleasant Valley (Study 1), New Scotland - Pleasant Valley (Study 2), and Leeds-Pleasant Valley (Study 3). The present value of the estimated carrying costs for each of the generic solutions was compared to the present value of projected production cost savings for a ten-year period, yielding a benefit/cost ratio for each generic solution. The NYISO also conducted scenario analyses to evaluate the congestion impact of changing variables in the base case assumptions. The scenarios were selected by the NYISO in collaboration with its stakeholders. The base case was modified to address potential regulatory changes in environmental emission requirements, full achievement of the State Renewable Portfolio Standard and the State Energy Efficiency Portfolio Standard, variations from the forecasted energy consumption and fuel prices, and the continued utilization of the Athens SPS for the ten-year study period. The 2011 CARIS Phase 1 report is available at:[13]

[13] Additional CARIS materials are available at: http://www.nyiso.com/public/markets_operations/services/planning/planning_studies/index.jsp.

http://www.nyiso.com/public/webdocs/services/planning/Caris_Report_Final/2011_CARIS_Final_Report__3-20-12.pdf

3.4.3 ISO-NE Economic Studies

ISO New England Economic Studies provide a range of information that can assist market participants and other stakeholders in evaluating various resource and transmission options for participating in New England‘s wholesale electricity markets. Under Attachment K to the ISO-NE OATT, the ISO is required to provide a forum for stakeholder review of the impacts of alternative system-expansion scenarios. This includes information on system performance, such as estimated production costs, load-serving entity energy expenses, estimates of transmission congestion, and environmental metrics.

The purpose of these studies is to test future resource additions and the effect of transmission constraints. While the evaluations are not an introduction to a specific Market Efficiency Transmission Upgrade (METU), the results can be used to identify the need for additional targeted studies.[14] This section describes economic studies conducted by ISO-NE since the completion of NCSP09.

3.4.3.1 New England 2030 Power System Study – Report to the New England Governors

In 2009 ISO-NE identified economic and environmental impacts (e.g., wholesale electricity prices and emission levels) for a set of scenario analyses hypothesizing the development of renewables as requested by the New England governors. This technical analysis was provided to the governors as an economic study performed through ISO-NE’s regional system planning process. The New England States Committee on Electricity (NESCOE), acting on behalf of the governors, submitted the request to the ISO, and the states developed the study assumptions with technical input from ISO-NE. The study was conducted to support the governors’ efforts to develop a renewable energy blueprint for the region. The study evaluated the integration of renewable resources, primarily wind, for a single year in the 20-year timeframe—around the year 2030. The study also evaluated the integration of varying levels of demand resources (i.e., energy efficiency and conservation), plug-in electric vehicles (PEVs), energy storage, and other load-modifying resources, which will be enabled by advances in smart grid technology. Additionally, the study evaluated possible generator retirements and the repowering of older fossil fuel generation with natural-gas-fired generation.

The study‘s primary findings indicate that New England has significant onshore and offshore wind resources that could be developed and added to the electric power system with appropriate transmission expansion. There were a myriad of alternatives with over forty cases developed that envisioned from 2,000 to 12,000 MW of new wind resources. The estimated transmission expansion costs to accommodate these ranged from $6.4 Billion for 1,015 new circuit miles to $25.2 Billion for 4,320 new circuit miles.[15] The report outlined trends and hypothesized workable transmission solutions but did not make any specific recommendations. One of the observations was that the conceptual transmission required to support the integration of New England wind resources indicated that connecting certain offshore wind resources results in the most cost-effective use of new and existing transmission—because it also allows for the integration of some near-shore and onshore wind generation. The study focused on the New England region and assumed that there would be no interregional impacts on the neighboring systems for the wind cases that relied on local wind. Renewable and low-carbon resources located nearby in eastern Canada could be available to New England with transmission expansions to the Québec and

[14] A Market Efficiency Transmission Upgrade is designed primarily to provide a net reduction in total production costs to supply the system load. Attachment N of the OATT describes the requirements for identifying a METU. For further details, see the ISO‘s OATT, Section II, Attachment N, ―Procedures for Regional System Plan Upgrades; http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[15] All transmission cost estimates are presented in 2009 dollars.

New Brunswick power systems, which are relatively modest expansion scenarios compared with the other conceptual transmission-expansion scenarios between New England and the Midwest that envisioned over 15,000 miles of new transmission, unprecedented coordination across the entire Eastern Interconnection and cost allocation of over $160 Billion. The final report was posted in February 2010.[16]

Another 2009 economic study request by New England stakeholders involved the coordination of production cost models with neighboring systems to jointly examine the performance of the interregional system as a whole. This study analyzed a series of scenarios for 2015 to account for planned load, resource expansion and retirements, and transmission configurations that could affect New York, New England, and PJM. The goal of this analysis is to identify where major interfaces are constraining interregional transfers by modeling NYISO, ISO New England, and PJM with approximate representations for their neighboring areas. The study assesses joint production cost analyses with both NYISO and PJM and includes the effects of relaxing various combinations of constrained transmission interfaces.

The initial phases of this study used the Interregional Electric Market Model (IREMM) production cost program, which is a simplified interregional model.[17] The analysis produced various metrics, including production cost, load-serving entity (LSE)[18] energy expenses, environmental emissions, and locational marginal prices of "load bubble" areas. As a follow-up effort, a more detailed representation of the interregional transmission network was created using PROMOD.[19] The IREMM and PROMOD studies are discussed in the NCSP11 Section 4.2.

3.4.3.2 2010 Economic Study Requests

As part of the economic study request by NESCOE in 2010 and to continue to provide technical support to NESCOE, the ISO conducted a follow-up analysis of the 2009 New England Governors' Renewable Energy Blueprint for integrating large-scale renewable energy resources into the region's electric power grid. This study continued investigating various resource additions into the New England resource mix as well as the impact of retiring coal, residual oil, and a combination of coal and residual oil resources. Resource additions hypothesized in this analysis were natural gas resources, wind, photovoltaic, biomass, and imported hydroelectric power from eastern Canada. The impact of plug-in electric vehicles also was analyzed. The major data refinements were to use wind and photovoltaic energy production data that were time-synchronized with a historical load profile. The time-synchronized wind data became available in 2010 as a result of the *New England Wind Integration Study*.[20] A discussion of the follow-up scenarios analyzed can be found in Section 13.1.1 of the 2011 Regional System Plan.[21]

[16] New England 2030 Power System Study: Scenario Analysis of Renewable Resource Development, Report to the New England Governors (February 2010): http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/economicstudyreportfinal_022610.pdf

[17] *IREMM* is a simulation tool the ISO has used in past production cost analyses for developing hourly, chronological, system-production costs and other metrics.

[18] Load-serving entities are electric utility distribution companies, except for municipally owned utilities, that sell basic electric energy service to end-use customers.

[19] PROMOD, GridView, MAPS, and other programs provide more detailed production cost representations of the transmission network than IREMM. For more information on the IREMM and detailed production cost program scopes of work and the differences between IREMM and these detailed production cost programs, see the June 2009 IPSAC presentation, http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2009/jun302009/index.html and the *2009 Northeast Coordinated System Plan* (see Section 14.2).

[20] The New England Wind Integration Study, final report (December 2010): http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf

[21] The 2011 New England Regional System Plan is available at: http://www.iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc.

The 2010 follow-up study showed that the system under the various scenarios would result in various patterns of fuel consumption by generators in the region attributable to the addition of combined-cycle resources, as well as wind, solar, and biomass resources, and the retirements of coal and residual oil resources. Similar to the results of the prior study, these results showed that, with adequate transmission, significant amounts of renewable resources could be added to the New England system. However, the study also highlighted concerns centered around New England's dependence on natural gas.

3.4.3.3 2011Economic Study Requests

New England stakeholders submitted three additional economic study requests in April 2011, all of which focused on expanded renewable resources within New England, including two that focus on development of renewables in western Maine. ISO-NE developed a final study plan to address all three requests. Preliminary results and a revised scope of work were shared with stakeholders in January 2012. The results will focus on illuminating the amounts of "bottled-in" wind resources in various locations around New England without the ability to effect significant near-term transmission system expansion. Results from the high-level IREMM production cost model will be completed by summer 2012. Continued analysis using a detailed transmission-oriented production simulation model is anticipated to be complete by the end of 2012.[22]

3.5 Summary

Because planning is a continuous function, the NCSP and other study results are based on the latest information that was available at the time the system analysis was initiated. Each of the ISO/RTOs has their own timelines for completing regional assessments and developing transmission plans. Some of this timing is the result of ISO/RTO tariff or market requirements while the timing of other studies may be driven by human resource constraints at the ISO/RTOs and supporting stakeholders. The JIPC will remain alert to opportunities that can improve interregional planning through better coordination of individual ISO/RTO work activities.

4 Summary of Interregional Studies

As discussed in Section 3, significant transmission investments have been made in recent years within ISO-NE, NYISO and PJM areas, and have resulted in increased reliability and greater market efficiency. Additionally, many new generation and demand-side resources have interconnected to each system. The JIPC has coordinated studies of internal system improvements with interregional effects and interconnections between the systems. This section discusses all the interregional studies that have recently been completed or are ongoing.

4.1 Transmission Improvements Having Interregional Impacts

Major system improvements within the ISO/RTOs, as well as those at or near the borders of a region, may affect the interregional system performance. The JIPC has worked to detect such issues by coordinating system models including the development of joint base cases and the representation of contingencies in neighboring systems. Although many improvements within the ISO/RTO systems are more local 115 kV and 345 kV transmission upgrades, their effects are assessed and coordinated across ISO/RTO borders, as may be required.[23]

[22] See: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/jan182012/2011_eco_study_scope.pdf
[23] ISO-NE's Project List is available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html

PJM has added several EHV facilities to its RTEP that were included in the analysis conducted in the Northeast Coordinated System Plan. These major backbone projects are expounded on in further detail in the 2011 RTEP Report. The need for these facilities was reevaluated in 2011 and continues to be reexamined in future RTEP analysis. Models used for interregional analysis were updated to include planned facilities based on the status available at the time of the analysis. The models used for NCSP analysis included the Carson – Suffolk and TRAIL projects, which are in service, and the Susquehanna – Roseland 500 kV project as a future study assumption. Each of these projects was added to the RTEP primarily to resolve thermal and reactive issues that were identified through PJM's reliability and deliverability criteria. These EHV upgrades are needed for the reliability of the PJM network. Extensive analysis of the impact of these lines on the PJM system as well as adjacent systems has been completed and will be reviewed as appropriate.

4.1.1 Status of Existing and Planned Interconnections between the ISO/RTOs

This section summarizes planned interconnections between PJM and NYISO and NYISO and ISO-NE.

4.1.1.1 PJM/NYISO

There are several existing transmission ties between PJM and NYISO. Generally these are in two groups: ties between Southeast NY (SENY) and New Jersey, and ties between New York State and Pennsylvania. The SENY ties are the phase shifter controlled ties between Jefferson and Ramapo and several ties that control a wheel of energy into PJM at Waldwick substation from Ramapo-South Mahwah branch (NY) and back out to the New York City zone from Hudson to Farragut and from Linden to Goethals. The ties in Western Pennsylvania are free-flow high voltage ties from Homer City to Watercure and Stolle Road, ties from East Towanda to Hillside and ties from Erie East to South Ripley, including several lower voltage ties.

More recently, there have been merchant transmission projects between PJM and New York that have increased the tie capacity between New Jersey (PJM) and SENY. The Neptune high voltage direct current (HVDC) project is a 685 MW firm withdrawal from PJM at Sayreville and injected into Long Island at Duffy Avenue. A variable frequency transformer (VFT) project linking Linden, NJ and New York City near Goethals is in service and accounts for 300 MW of firm withdrawal rights. Finally, a planned back-to-back direct current tie between Bergen, NJ, and West 49th Street in NYC has 320 MW of firm withdrawal rights from PJM, out of 673 MW requested. The remaining 353 MW would be treated as non-firm transmission withdrawal rights. Currently, the inter-regional tie is under construction with an in-service date no earlier than the summer 2013 season.

4.1.1.2 ISO-NE Ties to NYISO and NBSO

As part of the past ISO/RTO regional plans, several inter-area transmission ties were successfully planned and placed into service. Major upgrades and new ties between ISO-NE and neighboring areas include:

- The Northeast Reliability Interconnect Project, consisting of a second transmission tie line between New England and New Brunswick
- A replacement cable project upgrading the existing underwater Long Island Cable 1385 AC transmission tie between Norwalk, Connecticut, and Northport, New York
- The Cross Sound Cable, a DC merchant transmission tie between East Shore, CT and Shoreham, NY

Proposed transmission facilities within NYISO are listed in the NYISO 2011 Load & Capacity Data report, available at: http://www.nyiso.com/public/webdocs/services/planning/planning_data_reference_documents/2011_GoldBook_Public_Final.pdf
PJM's RTEP upgrades and status are available at: http://pjm.com/planning/rtep-upgrades-status.aspx

- The replacement of the phase angle regulator on the Plattsburgh – Vermont interconnection

Several conceptual interconnections between neighboring regions are under various stages of development, including merchant projects connecting the Bridgeport, CT area to the Long Island Power Authority (LIPA) and Plattsburgh, NY, to New Haven, Vermont. In addition, other developers have suggested projects interconnecting New England with Quebec, New Brunswick, and the other Atlantic Provinces.

4.1.2 Queue Projects with Potential Interregional Impacts

Coordination of interregional impacts of projects is a vital part of studies of new generation or transmission projects near the ISO/RTO borders. Thermal, voltage, stability, and short circuit analyses are conducted to ensure reliable plans are developed. ISO-NE, NYISO, and PJM update and coordinate short-circuit databases for the current system and representations of the future system. Power flow and stability databases and models are also updated.

All projects within an ISO/RTO are reviewed and where potential interregional impacts are recognized, the studies are coordinated with the appropriate neighboring systems on a case-by-case basis. The scopes of work are developed to reflect common databases, contingencies, and other considerations.

4.1.3 Loss-of-Source Analyses

Loss of Source (LOS) studies are important examples of interregional planning that impacts the three ISO/RTOs. These studies simulate the normal planning criteria contingency – loss of generating units and HVDC interconnections to assess interregional operating limits. In New England, the transfer limits from LOS contingencies are the higher of 1,200 MW or the more restrictive of PJM's and NYISO's internal limitations. Like other system contingencies, the LOS limits prevent adverse impacts from contingencies internal to New England on neighboring systems. During many periods studied and described in NCSP09, the 1,200 MW limit was projected to be binding and it was recognized there would be a number of potential benefits of having a higher loss-of-source limit. They include:

- The ability to import more power from Canada over the HVDC Phase II interconnection
- Fewer reductions in dispatch of larger nuclear units/stations and the Mystic units #8 and #9
- Reliable interconnections of large new generating units or new transmission tie lines to Canada
- Lower energy prices in New England and neighboring regions

Previous studies described in NCSP09 examined the effect of NYISO and PJM planned system improvements on system transfer capability. The results indicated the actual operations may be possible above 1,200 MW to a 1,400 MW to 1,500 MW range, which would be limited by constraints in PJM.[24] NCSP09 studies also showed that quick-fix improvements (e.g., addition of series reactors on the New York to New England tie lines) are not feasible methods of increasing the LOS limit. NCSP09 also summarized prefeasibility studies of replacing the 115 kV tie between Plattsburgh, NY and Vermont (PV-20) with a 230 kV tie. The results showed this improvement could also increase the Central East limit.[25]

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[24] These results were presented to IPSAC in December 2007. A December 2007 report on the subject is available at: http://www.interiso.com/public/meeting/20071214/20071214_Loss_of_Source_12-4-07.pdf

[25] These results are described in a June 2009 IPSAC presentation available at:http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2009/jun302009/nyvt.pptx

A detailed appendix describing these results is available at : https://smd.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/ceii/mtrls/2009/dec162009/vt-ny_appendix.pdf (New England CEII clearance required)

Consistent with analysis summarized in NCSP09, the LOS limit in operations has usually been higher than 1,200 MW, and on-peak flows on the Phase II tie have typically been approximately 1,400 to 1,500 MW. The JIPC will continue to monitor the flows on Phase II and consider conducting studies showing the effect of increased imports from Quebec using a coordinated production cost model.

4.2 Market Efficiency Analysis

Market efficiency analysis can be used to produce various metrics, such as system-wide production costs, fuel usage, load serving entity energy expenses, locational marginal price (LMP), and system emissions. Among other applications, these studies can be used to identify transmission constraints and quantify the effects of transmission improvements in relieving transmission constraints.

The Interregional Electric Market Model (IREMM) is a simulation tool that ISO-NE has used in past production cost analyses for developing hourly chronological system-production costs, as well as other metrics. IREMM is a high level simplified production cost model with a high level representation of resource dispatch and commitment. Loads are aggregated into subareas (a.k.a. bubbles) and transmission constraints are represented as transportation limits on major interfaces. IREMM offers advantages of easily understanding system performance and “seeing the forest for the trees” as a high level screening analysis. The high level model database aggregates and builds upon common data sources. It can be used to develop a representation of interchange with external systems that can be imported into more detailed production cost programs such as those used by PJM and NYISO. Through the years IREMM has benchmarked well with other production cost programs.

Detailed production cost programs (such as PROMOD, GridView, MAPS) have a full representation of unit dispatch and commitment together with a comprehensive system-wide load flow representation. Because detailed transmission constraints can be explicitly modeled, these types of production cost programs allow a more detailed understanding of system performance. Development of detailed production program data bases requires considerable effort and care. ISO-NE is currently working towards adoption of the GridView platform, which will better align future simulation modeling with NYISO/PJM production cost platforms.

Coordinated production cost data bases were developed among the NYISO, PJM, ISO-NE, and neighboring systems for both IREMM and detailed production cost programs. The JIPC conducted studies of the future system to identify transmission interfaces that may limit economical interregional transfers and to quantify the effects of relieving the identified transmission constraints. The results of this analysis would then be used to provide guidance for subsequent transmission analyses. (See Section 11.2)

4.2.1 Market Efficiency Analysis of the NYISO/PJM Area

A market efficiency analysis, using the PROMOD market simulation software, was conducted for the PJM, ISO-NE and NYISO footprint. The goals of the analysis were twofold:

- Developing an initial detailed nodal market representation of the combined areas, and to perform an annual hourly market simulation for the calendar year 2017.
- Examining the potential economic benefits of any reliability upgrades that could evolve from the reliability study discussed above (refer to Sections 3.1 and 3.2).

The production cost database was successfully coordinated by the three ISO/RTOs. The baseline market efficiency model and analysis produced can be used in evaluations of the potential economic benefits of any specific transmission project. The JIPC will continue to identify opportunities and benefits of increased transmission ties between neighboring RTOs.

The input data for the modeling of the footprint was based on the publicly available Ventyx database. The analysis used load and capacity assumptions consistent with each ISO/RTO region's forecasts. The system topology was consistent with each region's respective 2011planning models. The constraints modeled for PJM included major (reactive limited) interfaces as well as key constraints that were typically modeled in internal PJM market efficiency studies. Additionally, key constraints internal to ISO-NE and NYISO and major interfaces between NYISO and ISO-NE were also modeled in the analysis. The following PJM in-service backbone expansion projects were included in the base case:

- Carson – Suffolk 500 kV line
- TRAIL (502 Junction – Loudoun 500 kV)

The Susquehanna – Roseland 500 kV backbone expansion project was also included in the base case as a future assumption for the study. Merchant transmission projects between PJM and NYISO were modeled as follows:

- Neptune HVDC modeled at 685 MW exporting to LIPA according to its firm withdrawal rights
- Linden VFT modeled at 300 MW exporting to ConEd according to its firm withdrawal rights
- Hudson Transmission Project 673 MW HVDC (PJM Queue O66 and NYISO Queue 206) modeled at 320 MW exporting to ConEd according to its firm withdrawal rights

The merchant transmission project between NYISO and ISO-NE was modeled as follows:

- Cross Sound Cable HVDC modeled at 330 MW from New Haven (CT) to Shoreham (Long Island, NY)

In addition, the assumptions for 2017 monthly fuel prices in the analysis are shown in Figure 4-1. The cost of CO_2 and NO_x emission allowances are assumed to be zero because of uncertainty in environmental regulation, federal legislation, emission trading, and their future prices at the time the analysis assumptions were set. Current RGGI allowance prices were not used in order to maintain consistency since many of the PJM zones do not belong to the RGGI program. However, the cost of SO_2 allowances was assumed to be $459 per ton based on the default cost from the Ventyx database.

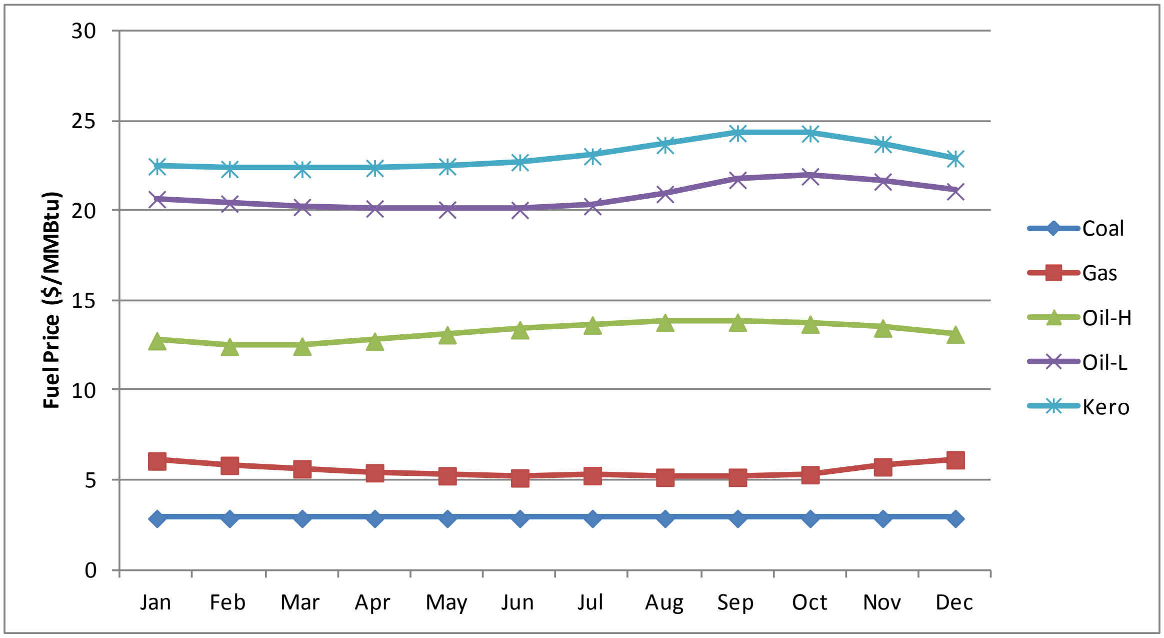

Figure 4-1: Monthly fuel prices (nominal dollars) used in the PROMOD analysis

Also, the following key modeling assumptions were made in the analysis:

- Boundary flows were modeled by using historical flows for PJM-MISO, NY-IESO, NY-HQ, NE-HQ and NE-NB.

- Hurdle rates were developed for the interface between PJM and NYISO based on the latest benchmarking analysis done for the 2011 historical year. Hurdle rates were adjusted until there was alignment of historical congestion costs in PJM for the year 2010 and the latest historical flows between PJM and NYISO from September 2010 through April 2011. The estimated congestion costs for PJM from the benchmark case was $1.63 billion, compared with $1.43 billion of total PJM congestion costs for 2010 and $1.72 billion in day-ahead congestion costs.[26] The PROMOD simulated flow between PJM and NY align with the historical flows for all seasons except for Fall season, where unit outages and other issues may account for the differences.

4.2.1.1 Selected Eastern PJM/NYISO Interfaces

- The Public Service/ConEd Wheel was modeled with an operating range between 1,000 MW and 1,200 MW. An additional sensitivity run with an operating range between 700 MW to 1,000 MW did not change the high-level results. In future simulations the wheel model will be updated to reflect to the most recent wheel agreement.

- The Ramapo phase angle regulators (PARs) in NYISO regulated between 300 MW and 800 MW to allow for economic transfer into NYISO. An additional sensitivity run, made between -1,000 MW and 1,000 MW at Ramapo PARs, did not change the high-level simulation results.

[26] Refer to the 2010 PJM State of the Market Report, available at: http://pjm.com/documents/reports/state-of-market-reports/2010-state-of-market-report.aspx

4.2.1.2 Results

Simulation results produced the projected average hourly nodal prices (LMP) by zone and the most significant constraints causing price separations. The estimated total system congestion cost for the entire PJM, ISO-NE and NYISO footprint for the year 2017 simulation was about $800 million.[27]

Examination of these high level results showed that the results are consistent with current market conditions. However, some of the detailed results may have differences if compared with the NYISO CARIS study due to different assumptions and methodologies. These differences will be included in future work scopes to continue to strive for consistency between regional and interregional study results. The additional sensitivity cases around controlled devices controlling power flows along eastern PJM and Southeastern NY border revalidated the underlying database and modeling assumptions used in the latest interregional market efficiency analysis.

Figures 4-2 and 4-3 illustrate the primary results – annual production cost and annual average zonal prices - from the base case of interregional market efficiency modeling. Sensitivity cases included low gas prices ($4.50 per MMBtu), high gas prices ($12.36 per MMBtu), a CO_2 adder ($2/ton) and transmission representation without the Susquehanna-Roseland project.

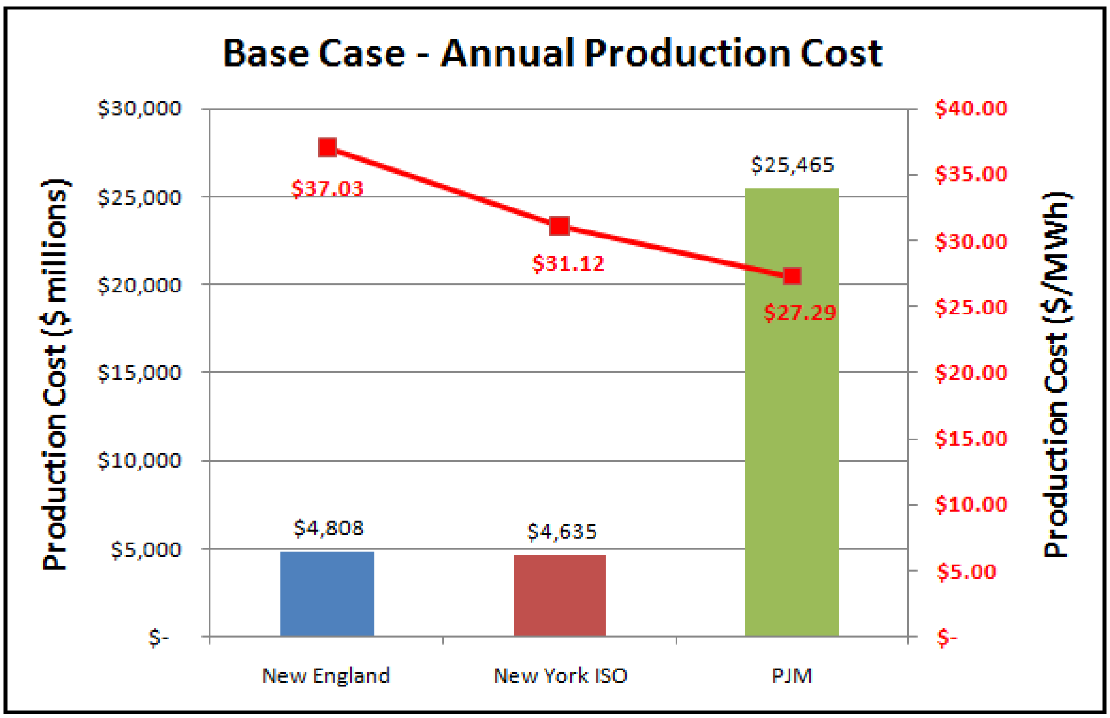

Figure 4-2: Total annual ISO/RTO production costs

[27] Estimated total system congestion costs are presented in 2017 nominal dollars and reflect an assumed fuel escalation rate of 2.5%.

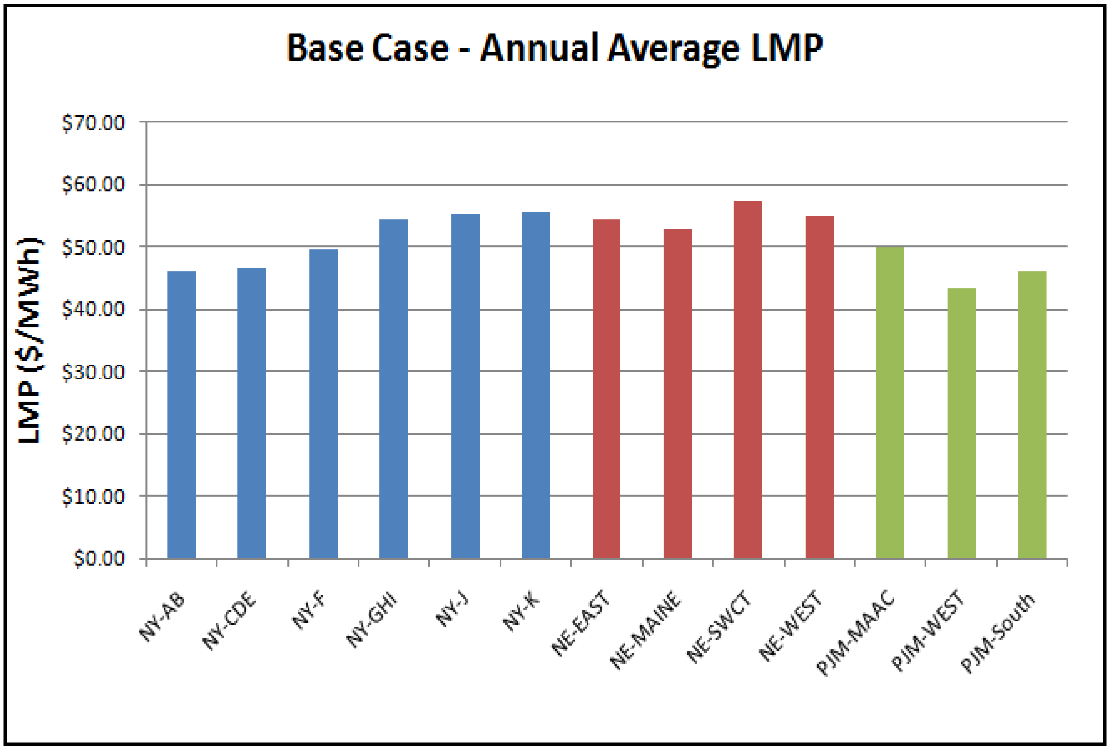

Figure 4-3: Annual average zonal LMPs

4.2.2 Market Efficiency Analysis of the NYISO/ISO-NE Area

In 2009 an ISO-NE Planning Advisory Committee (PAC) stakeholder submitted a request for an economic study to investigate the economic benefits of increased transfer capability between New England and New York that hypothesized an abundance of wind energy in the northeastern area of New York State. As a result, ISO-NE began developing an economic planning study with the participation of both NYISO and PJM. The resulting collaborative study investigated analytical tools, sources of data, and techniques for performing studies of this nature.

The assumptions and methodology of the study were discussed with the IPSAC in 2010, and interim and final study results were presented at the IPSAC meetings held March and June 2011.[28] As a result of the study, coordination of interregional databases has been achieved, which has resulted in increased understanding of the issues affecting the three ISO/RTOs. Plans for transmission expansions were also reviewed, and the impact of interface limits are now better understood and incorporated into the database.

Based on the results of the study, the following was observed:

- The IREMM production cost analysis study provides insights into the 2015 interregional economic energy flows.

[28] February 2, 2010: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2010/apr302010/ipsac_iremm.pdf
April 30, 2010: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2010/apr302010/ipsac_iremm.pdf
October 29, 2010: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2010/oct292010/iremm.pdf
March 30, 2011: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/mar302011/ipsac_iremm.pdf
June 27, 2011: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/jun272011/iremm.pdf

- Validation of the metrics has provided confidence that the models are reasonable.
- The effect of high CO_2 Allowance values may change the characteristics of the energy flows between the ISOs/RTOs.
- Exports from New England to New York would tend to increase if the price of CO_2 Allowances increases.
- As New England imports increase from Quebec, exports to New York have a tendency to increase concurrently.
- Additional wind within the "North Country" in upstate New York:
    - Is shown to displace predominantly New York generation.
    - Results in little net change in transfer between New England and New York.
    - Additional uncontrolled transmission between the "North Country" and Vermont may cause loop flow that would exacerbate ISO-NE's North/South Interface.

The process provided illustrations of how the benefits of increasing transfer limits between New England and New York, as well as between New York and PJM, could be evaluated. The relatively minor change in metrics show the need for follow-up studies using improved modeling of the system using nodal production cost programs. These would more fully capture system performance issues, such as loop flow. A possible outcome of subsequent studies could be a recommendation to strengthen the tie lines among the regional ISOs/RTOs. Final identification of transmission upgrades, however, would require follow-up detailed interregional and regional transmission planning analyses and coordinated production cost simulations.

4.3 Summary

In summary, the JIPC has coordinated planned interconnections between ISO/RTOs, system models, internal system improvements, the development of joint base cases and the representation of contingencies in neighboring systems. Market efficiency analysis conducted to date with both a high level model (IREMM) and a detailed production cost model (PROMOD) has not identified a firm need for new transmission for either reliability or economic reasons among the ISO/RTOs.

5 Additional Coordinated Planning

ISO New England, NYISO, and PJM participate in the ISO/RTO Council (IRC), an association of the North American Independent System Operators and Regional Transmission Organizations. ISO New England and NYISO are actively participating in NPCC interregional planning activities along with the Canadian Members of NPCC and the technical participation of PJM. All of the ISO/RTOS are participating in a number of other activities designed to improve interregional coordination with other ISOs and RTOs. Several major interregional activities that are supported by the three ISO/RTOs are discussed below.

5.1 Coordination of Studies and Databases

The development and updating of common databases and their interregional coordination is required for interregional planning studies. The starting point is the development and/or updating of each ISO/RTO's transmission databases and models, which then becomes inputs to interregional planning processes. The key inputs are:

- Load forecast updates
- Resource requirements/reserve margin
- Base case resources: supply, transmission and demand response

- Models: Load flow (PSS/E), resource adequacy (MARS), production cost (MAPS, PROMOD, GridView and IREMM), stability (PSS/E), short circuit (ASPEN and PTI)

Regional studies that are typically conducted include:

- Resource adequacy
- Reliability assessments
- Economic (production cost or congestion) analysis
- Interconnection studies: generation and merchant transmission
- Requests for transmission service
- Special studies, e.g. scenario analysis, wind integration, environmental and fuel

Many interregional updates of databases/studies are done annually or periodically as needed. National updates include FERC Form 715, EIA Form 411 and DOE congestion studies. NERC updates include ERAG, GADS and TADS. NPCC/RFC updates are NERC databases coordinated through NERC regional entities. The Northeastern Protocol uses the updates for the other entities and customizes them as needed for Northeast regional studies.

Database development, updating and studies are an ongoing process and this is coordinated across regions. In this process the regions share lessons learned, best practices, and advances in technology and software.

5.2 Northeast Power Coordinating Council

Northeast Power Coordinating Council, Inc. (NPCC) is a 501(c)(6) not-for-profit corporation in the state of New York responsible for promoting and improving the reliability of the international, interconnected bulk power systems in Northeastern North America through:

i. The development of Regional Reliability Standards and compliance assessment and enforcement of continent-wide and Regional Reliability Standards, coordination of system planning, design and operations, and assessment of reliability (collectively, Regional Entity activities); and,
ii. The establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria (collectively, criteria services activities). NPCC provides the functions and services for Northeastern North America of a cross-border Regional Entity through a Regional Entity division, as well as Regionally-specific criteria services for Northeastern North America through a criteria services division. NPCC's website is www.npcc.org.

NPCC is one of eight regional entities located throughout the United States, Canada, and portions of Mexico that are responsible for enhancing and promoting the reliable and efficient operation of the interconnected bulk power system. The NPCC Region covers nearly 1.2 million square miles and is populated by more than 55 million people. NPCC U.S. includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia.[29]

Among the five NPCC areas, the Maritimes and Québec are winter-peaking systems. Ontario historically experienced its annual peak demand in the winter but recently has become a summer-peaking system. The New York and New England areas continue to be summer-peaking systems. Owing to the mix of winter- and summer-peaking balancing authority areas, the wider NPCC region has reserves to share among the

[29] As full members, New Brunswick and Nova Scotia also ensure that NPCC reliability issues are addressed for Prince Edward Island.

areas during the seasonal peaks. This seasonal diversity also changes the overall summer and winter system flows of electric power and energy within and between the balancing authority areas.

ISO New England and NYISO are committed to the goals and objectives of NPCC and agree to plan and operate their systems in full compliance with NERC Reliability Standards,[30] NPCC Regional Reliability Standards and Directories,[31] and, for New York State Reliability Council Reliability Rules.[32] They are also active participants in NPCC interregional studies and planning initiatives with the full technical participation of PJM.

5.2.1 Coordinated Planning

NPCC initiates studies of its geographic areas and coordinates member-system plans to facilitate interregional improvements to reliability. The NPCC also evaluates its areas' assessments, resource reviews, and interim and comprehensive transmission system reviews. NPCC conducts short-term assessments to ensure that developments in one region do not have significant adverse effects on other regions. As members of NPCC, ISO New England and NYISO fully participate in NPCC-coordinated interregional studies with its neighboring areas, including PJM.

NPCC's Task Force on Coordination of Planning (TFCP) reviews the resource adequacy of the NPCC member systems to supply load, accounting for forecasted demand and planned resources. The reviews are accomplished in accordance with the NPCC Regional Reliability Reference Directory No. 1, "Design and Operation of the Bulk Power System."[33] The TFCP also reviews the compliance of NPCC area future proposed transmission plans with the basic criteria consistent with the *Guidelines for NPCC Area Transmission Reviews*.[34] All studies are well-coordinated across neighboring area boundaries and include the development of common databases that can serve as the basis for internal studies by the ISO.

In coordination with NERC, NPCC also gathers data and assesses the existing and future resource adequacy of its five areas.[35]

5.2.2 Resource Adequacy Analysis (CP-8)

Under the CP-8 Working Group (CP-8 WG), NPCC coordinates resource adequacy studies of its five balancing authorities' regions and provides technical support that is necessary for the evaluation of the resource adequacy of the NPCC region. PJM, though not a member of NPCC, is an active participant in the analysis.

NPCC conducts comprehensive summer and winter reliability assessments of the NPCC region, which include a multi-area probabilistic analysis. PJM collaborates in these studies by providing data for modeling the outside region to NPCC.

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[30] See: http://www.nerc.com/page.php?cid=2
[31] See: https://www.npcc.org/Standards/default.aspx
[32] See: http://www.nysrc.org
[33] See Appendix D - Guidelines for Area Review of Resource Adequacy: https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20Full%20Member%20Approval%20December%2001,%202009%20GJD.pdf
[34] See Appendix B - Guidelines for NPCC Area Transmission Reviews: https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20Full%20Member%20Approval%20December%2001,%202009%20GJD.pdf
[35] The NERC Reliability Assessment Subcommittee (RAS) publishes several reports; see http://www.nerc.com/page.php?cid=4|61.

In addition, comprehensive Balancing Authority reviews of resource adequacy are due every three years, with interim reports the other years.[36] The comprehensive and interim resource adequacy reviews demonstrate compliance with the NPCC Resource Adequacy Design Criterion:

> "The probability (or risk) of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."[37]

The results of NPCC Reliability Assessments[38] indicate that the NPCC and the associated Reliability Coordinator areas have adequate generation and transmission for both the 2011 summer and the 2011-2012 winter operating periods, and have developed the necessary strategies and procedures to deal with operational problems and emergencies as they may develop.

In addition to the seasonal reliability assessments, the NPCC CP-8 WG also conducts an annual Long Range Adequacy Overview[39] that evaluates, on a consistent basis, the long range resource adequacy criteria. The annual NPCC Long Range Adequacy Overview provides the basis for the NERC Pilot Probabilistic Reliability Assessment. The objectives of this new NERC report are to provide a common set of probabilistic reliability indices for future planning years and to recommend probabilistic-based work products that may be used in the future to supplement the NERC's Long-Term Reliability Assessments (LTRA). In addition, NPCC periodically performs an interconnection assistance reliability benefit study to:

1. Estimate (on a consistent basis) the amount of interconnection benefits available to the NPCC Areas for a five year period;
2. Review each NPCC Area's current estimates of interconnection benefits used to meet the NPCC Resource Adequacy Criterion; and,
3. Verify that the current levels of interconnection benefits assumed in each Area's resource adequacy assessments are reasonable and do not result in overstating any Area's reliability.

In all the above studies, the GE MARS program[40] is used for evaluating the resource adequacy of each region. These analyses include models of forecast simultaneous transmission constraints within each

[36] Available at: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[37] See Section 5.2 – Resource Adequacy Design Criteria: https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20Full%20Member%20Approval%20December%2001,%202009%20GJD.pdf
[38] NPCC Reliability Assessment for Summer 2010: https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_for_Summer_2010_Final%20Report.pdf
NPCC Reliability Assessment for Winter 2010-2011: https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_2010-11W%20_Final_Report.pdf
NPCC Reliability Assessment for Summer 2011: https://www.npcc.org/Library/Seasonal%20Assessment/CO-12_2011_Summer%20Reliabbility%20Assessment%20Final%20Report.pdf
NPCC Reliability Assessment for Winter 2011-12: https://www.npcc.org/Library/Seasonal%20Assessment/NPCC_Reliability_Assessment_2011-12W_Final_Approved%20Report.pdf
[39] Available at: https://www.npcc.org/Library/Resource%20Adequacy/Forms/Public%20List.aspx
[40] See: http://site.ge-energy.com/prod_serv/products/utility_software/en/ge_mars.htm

region and between regions, forecast load levels and uncertainties, and forecast individual generation availability.

5.2.3 NPCC Overall Transmission Assessment

The NPCC Task Force on System Studies (TFSS) performs a periodic Overall Transmission Assessment (OTA) of the reliability of the planned NPCC bulk power system.[41] The study examines the system from a broad regional and inter-regional perspective by building upon and supplementing the transmission reviews conducted annually by each of the NPCC areas.

The latest OTA study was conducted in 2009 by the NPCC SS-38 Working Group under the direction of TFSS. This study assessed dynamic and steady state performance of the entire NPCC system for various design and extreme contingencies under conditions projected for 2013. Assumptions for the base case included:

- 500 kV and 765 kV facilities proposed within PJM
- Inter-Area and inter-regional interface transfer simultaneously stressed at higher levels than those typical

The 2009 OTA study showed:

- For all tested design contingencies originating within and outside the NPCC region, the NPCC system projected for 2013 remained stable with no inter-Area and interregional impacts;
- For all but one of the tested extreme contingencies originating within and outside the NPCC region, the NPCC system projected for 2013 remained stable with no inter-Area and interregional impacts. For the only one problematic contingency, a damped response was observed when key interface flows were reduced to levels that are more appropriate for extreme contingency testing;
- For all simulated beyond normal criteria contingencies, the NPCC system projected for 2013 exhibited an acceptably stable and damped dynamic response; and,
- The proposed large future system developments in the adjacent RFC region did not negatively impact the dynamic performance of the NPCC system projected for 2013 for all tested contingencies originating within and outside the NPCC region.

In summary, the study results demonstrate the robustness of the NPCC system and in general are consistent with the findings of past OTAs.

As required by the scope of 2009 OTA study, the dynamic performance with high penetrations of wind generation was also studied as an addendum to the 2009 OTA study. The 2013 light load base case was developed with the inter-Area and inter-regional interface transfer simultaneously stressed over typical values. A total of 5,833 MW of wind powered generation was assumed and dispatched in the NPCC Region in this base case, as listed in Table 5-1.

[41] Available to NPCC Members at: https://www.npcc.org/Library/Transmission/Forms/Public%20List.aspx

Table 5-1: List of wind power characteristics by NPCC area

	NPCC Area				
	New York	New England	Ontario	Québec	Maritimes
Area Wind Powered Dispatch (MW)	2,244	930	952	1,198	509
Area Net Load (MW)	18,495	13,880	12,399	22,299	2,502
Penetration of Wind on Net Load (%)	12.1	6.7	7.8	5.4	20.3

The NPCC system performance demonstrated stable and well damped dynamic response with no voltage or thermal violations that could adversely impact reliability for all but three of the tested contingencies. Among these three contingencies, two of them are not directly related to the high level of wind power generation dispatch. And the one, which involves the islanding of the Maritimes Area and Bangor area, shows the impact of wind penetration on the frequency response of the isolated island due to the contingency. The island frequency rose more rapidly and settled to a higher value with high wind generation dispatch. This difference in frequency response is due to the lack of inertial and governor response from wind turbine generators.

During the simulations, for certain tested contingencies, the tripping of some Wind Powered Plants (WPP) were observed. The impacts from these WPP trips were local in every case.

5.3 RFC 2020 Long-Term Assessment of Transmission System Performance

As one of the eight NERC-approved Regional Entities in North America, Reliability*First* Corporation (RFC) conducts a long-term transmission assessment annually in order to satisfy its responsibility to provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the applicable assessment period as required by NERC reliability standards. RFC complies with this mandate by examining work already performed according to the planning processes of PJM, MISO, MRO, SERC, and VACAR and studies performed by the Eastern Reliability Assessment Group (ERAG). In addition, RFC performs its own long term transmission assessment in conjunction with affected transmission owners, which includes identification, analysis, and projections of trends in transmission adequacy and other industry developments that may impact future electric system reliability.

In November 2011, RFC issued a report summarizing the results of a long-term assessment of the projected performance of the transmission system within RFC's footprint for the 2020 Summer peak season.[42] The assessment did not attempt to determine load or generator deliverability, Planning Transfer Capability (PTC), Available Transfer Capability (ATC), Available Flowgate Capacity (AFC), the availability of transmission service, or provide a forecast of anticipated dispatch patterns for the 2020 Summer season.

The assessment evaluated the performance of the transmission system within RFC via a series of power flow analyses. The assessment was based on the transmission topology, load and generation dispatch modeled in the 2020 EIPC Summer Peak roll-up case.

The base case was examined under NERC criteria category A and B conditions. The case was then stressed under thirty-one different transfer scenarios that were considered to represent severe system conditions that may be experienced under adverse weather, generation deficiencies, transmission configuration or other emergency type situations. These tests go beyond the normal RTO NERC criteria

[42] See RFC's 2020 Summer Long-Term Assessment of Transmission System Performance (November 2011): https://www.rfirst.org/reliability/Documents/RFC%202011%20Assessment-Long-Term%20Transmission-2020S.pdf

testing that would require upgrades for reliability. RTO internal planning processes establish all needed system upgrades for full compliance with NERC criteria.

Based on the results of the work conducted by RFC, MISO, PJM, and ERAG and summarized in this assessment report, it is expected that the transmission system within the RFC footprint will perform well over a wide range of conditions. However, future transmission reliability is dependent upon transmission planning decisions made in response to state and federal government policy, as well as public and regulatory responses to proposals to construct new transmission.

Over the past several years, an increasing focus by federal and state governments on environmental issues, energy independence and other policy areas continues to highlight the critical role of the transmission system in meeting policy goals. Consequently, while compliance to NERC reliability standards as the primary basis for the determination of need has been the precedent, future planning and construction of major transmission infrastructure will likely be necessary to support the achievement of public policy goals.

An important element of these goals is greater use of renewable resources, primarily wind generation. Integrating wind resources that are often distant from load centers presents a unique set of challenges to planning new transmission. Moreover, planning processes continue to address the need to strengthen the nation's electrical grid to accommodate the retirement of generating resources not able to meet environmental regulations, including those regarding NO_x, SO_2, Hg, CO_2 emissions and water quality. It is also important to consider the timelines associated with public policy goals and regulations. When a generator owner determines that capacity should be retired, it takes a minimum of two to three years to build a combustion turbine to replace that capacity. Also, if transmission system reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to come into service. Once final environmental regulations are issued, compliance deadlines may be difficult to meet for some situations throughout the system. Whether taken individually or addressing their collective impact, many such public policy goals and regulations necessarily impact transmission planning decisions.

Note that other studies that are seasonal and more near-term in scope are also periodically conducted by RFC. These studies are not summarized here, but can be found at: https://www.rfirst.org/reliability/Pages/ReliabilityReports.aspx.

5.4 IRC Activities

Created in April 2003, the ISO/RTO Council is an industry group consisting of the 10 functioning ISOs and RTOs in North America. These ISOs and RTOs serve two-thirds of the electricity customers in the United States and more than 50% of Canada's population. The IRC works collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across North America. In fulfilling this mission, the IRC balances reliability considerations with market practices that encourage the addition of needed resources. As a result, each ISO/RTO manages efficient, robust markets that provide competitive and reliable electricity service, consistent with its individual market and reliability criteria.

While the IRC members have different authorities, they have many planning responsibilities in common because of their similar missions to independently and fairly administer an open, transparent planning process consistent with established FERC policy. As part of the ISO/RTO authorization to operate, each ISO/RTO has led a planning effort among its participants through an open stakeholder process. Specifically, the transmission planning process must provide for coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. This ensures a level playing field for infrastructure development driven efficiently by competition and meeting all reliability requirements.

The IRC has coordinated filings with FERC on many issues, such as those concerning the administration of the ISO‘s Generator Interconnection Queue and other technical issues. For example, the IRC has identified issues and is acting to address the challenges of integrating demand resources and wind generation and, through its representatives, is leveraging the efforts of NERC‘s Integrating Variable Generation Task Force (see Section 8.1.2). The IRC has representation on other NERC task forces and committees.

Early in 2011, FERC finalized a comprehensive, multiyear effort to measure the performance and benefits of ISOs/RTOs, for which six ISO/RTOs had compiled a joint report. On April 7, at the behest of the US Senate Homeland Security and Governmental Affairs Committee and the Government Accountability Office, FERC submitted to Congress a "metrics report" containing 57 performance metrics that cover numerous topics, including market efficiency, power system reliability, and overall organizational effectiveness.[43] Among other things, the report provides an empirical analysis of the benefits of organized power markets, identifies best industry practices, and (where possible) directly compares the varying successes of regional grid operators. The specific metrics are divided among broader measurements of power system reliability, efficient and effective market operations, and organizational effectiveness. The ISOs/RTOs submitted an updated metric report to FERC in August 2011.[44] The IRC is currently working on an updated metrics report that will be submitted to FERC late in 2012.

In 2011 the IRC worked to establish a common foundation for new variable energy resources, including renewable and demand response resources, with particular recognition of fuel supply reliability. All IRC member ISOs and RTOs shared performance requirements for wind resources with respect to voltage regulation and reactive power capability, voltage ride through, frequency variations, and ramp rates/curtailment. The IRC reviewed all submitted requirements and identified commonalities, as well as any differences that could serve as the basis for new future requirements across ISO/RTOs. IRC also reviewed work conducted by the NERC Functional Model Demand Response Advisory Team that provided a basis for assessing active demand resources.

5.5 NERC Eastern Interconnection Reliability Assessment Group

The three Eastern Interconnection Reliability Assessment Group (ERAG) interregional study forums – SERC[45] East-RFC (SeR), RFC-NPCC (RN) and Midwest Reliability Organization-RFC-SERC West-SPP[46] (MRSwS) – are under the direction of the ERAG Management Committee (ERAG MC). In June 2011, the SeR and RN Steering Committees were merged to form the SeRN Steering Committee (SeRN SC). At that time, both the SeR and RN Working Groups were assigned to report to the SeRN SC.

The SeR and RN Working Groups, under the direction of the SeRN SC, conducted a study[47] appraising the interregional transmission system performance among the SERC East-RFC-NPCC regions for the

[43] FERC, Performance Metrics for Independent System Operators and Regional Transmission Organizations (Washington, DC: FERC, April 2011), http://www.ferc.gov/industries/electric/indus-act/rto/metrics/report-to-congress.pdf.
[44] The 2011 ISO/RTO Metrics Report is found at: http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/ad10-5-00_8-31-11_joint_iso-rto_metrics_report.pdf
[45] SERC is the SERC Reliability Corporation, which is responsible for promoting and improving the reliability, adequacy, and critical infrastructure of the bulk power supply systems in all or portions of 16 central and southeastern states; see: http://www.serc1.org/Application/HomePageView.aspx
[46] SPP stands for Southwest Power Pool, the RTO providing services to its members in Arkansas, Kansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma, and Texas.
[47] ERAG reports are available at: https://www.npcc.org/RAPA/ERAG/Forms/Public%20List.aspx

conditions expected during the 2020 summer period. The appraisal was performed in support of the NERC reliability standards TPL-005.

This effort models transfers between areas that reflect the changing transmission market and the Regional Reliability Organization (RRO) affiliations of transmission owners. For example, if the PJM market is the source or the sink for the transfer, the designation will be PJM and includes all participants in the PJM market.

The purpose of the study was to provide:

- An analysis of First Contingency Incremental Transfer Capabilities (FCITC) for selected transfers that may occur simultaneously between or through members of the RFC, SERC East and NPCC regions.
- FCITC values (as defined in Appendix E of the assessment) for non-simultaneous emergency transfers among MISO, SERC East, PJM, IESO, and NYISO.
- Appraisals for the MISO, PJM, IESO, NYISO and SERC East study areas.
- An increase in planner awareness by testing the ability of the BES to reliably accommodate emergency power transfers among operational entities.

The FCITC values reported in the assessment were based on simulated system operation. If appropriate, changes in operations which are expected to occur prior to the 2020 summer study period are discussed in the individual regional or sub-region assessments.

The reported FCITC values are based on the prediction of many factors that actually change during the daily operation of the power system. Among these variable factors are:

- Load forecasts and generation availability
- Geographic distribution of load and generation
- Transmission system configuration
- Simultaneous inter-system power transfers
- Operation based on regional requirements to respect additional contingencies
- Control settings of phase angle regulators

A companion report of the interregional system performance is presented in the MRO-RFC-SERC West-SPP 2020 Summer Interregional Transmission System Reliability Assessment from the MRSwS study forum.

5.5.1 Base Case Development and Study Procedure

The base case used in the 2020 summer assessment was developed from the EIPC 2020 Summer Roll-up case with assistance from the Multiregional Modeling Working Group (MMWG), which modeled firm, capacity backed transfers. This was updated with the most recent transmission system status information and projected transfers. The base case was also updated to reflect the MISO and PJM market dispatch profiles.

To assess the ability of the SeRN study area to support emergency transfers between the member regions, in addition to the base transfer in the case, cases were developed with test transfer levels of 1,000, 2,000, and 2,500 MW for transfers involving IESO or NYISO as a source or sink. A 3,000 MW test transfer case between PJM and the NYISO were developed for analysis but did not result in reportable limits. A 4,000 MW test transfer level was used for transfers between MISO, PJM, and SERC East. Each test transfer case was created by imposing the test transfer on the base case and making the necessary system adjustments required to support the transfer. For the transfers not involving IESO or NYISO as source or sink, the base case was used with no further adjustments.

5.5.2 Executive Summary of Results

The following observations and conclusions were made based on the results of the 2020 summer assessment:

1. A Midwest ISO security constrained market dispatch was modeled for the 2020 summer study base case. Therefore, any comparison of the transfer limits reported in this assessment with those from previous studies needs to acknowledge differences between the current market-based topology used in this study and the regional dispatches used in other studies.

2. Because the 2020 summer study represents emergency conditions, the PARs for the four Michigan-Ontario interface circuits were modeled to reflect their anticipated summer schedules and operation.

3. Assuming all transmission facilities are in service, power flows on the PJM, MISO, SERC and NPCC bulk power transmission systems are within acceptable limits for the power transfers modeled in the base case. Also, assuming all operating procedures are appropriately employed, no single contingency on the bulk power transmission system will overload the remaining facilities, which are affected significantly by the transfers reported in this study.

4. The reported FCITC values were rounded to the nearest 50 MW, and are listed in Table 5-2.

Table 5-2

Transfer Scenario	FCITC (MW)
IESO-NYISO	2,450
IESO-MISO	3,000
PJM-NYISO	850
NYISO-IESO	1,650
MISO-IESO	2,450
NYISO-PJM	4,000+

Non-simultaneous FCITCs are used as indicators of the relative strength of the interconnected system. They cannot be used as absolute indices of the operating capability of the system because they are only determined for the specific system conditions represented in the base case. Any changes to the system conditions, such as variations in generation dispatch or other transfers not modeled in the base case can significantly affect transfer capabilities. The FCITCs determined for the SeRN study area for the 2020 summer peak load conditions are summarized in Table 1 of the assessment.

Due to the integrated nature of the bulk supply network, power transfers between areas can result in incremental power flows throughout the SERC East-RFC-NPCC regions. In some cases, the resulting power flow through a part of the region not involved in the transfer can be significant.

When considered independently, these transfers may not appear to pose a problem within the maximum permissible transfer value. But for certain combinations of simultaneous power transfers, portions of the interconnected network could experience significant power flow increases when the responses to the transfers are in the same direction. Conversely, a transaction may also decrease the prevailing flow and allow for increased transfers.

5.6 NERC Long Term Reliability Assessment

In November 2011, NERC issued its annual Long Term Reliability Assessment (LTRA), analyzing reliability conditions across the North American continent.[48] This report describes transmission additions, generation projections, and reserve capability by reliability council area. Both RFC and NPCC show that, within a ten year planning horizon, they are expected to have sufficient reserves to meet reliability needs. Projected sluggish load growth within NPCC over the assessment period is attributed to a combination of energy conservation initiatives and a slow economic recovery. Challenges noted for NPCC include aging infrastructure issues, the integration of variable resources and the retirement of fossil-fueled generation. New additions to the bulk power system within the RFC area are anticipated to result in enhanced reliability, including 2,470 miles of transmission that will be constructed within the ten-year time frame. These generation and infrastructure improvements will ensure both areas meet LOLE of 1 day in ten years in the 2020 calendar year.

5.7 Eastern Interconnection Planning Collaborative

5.7.1 Background

In March 2009, pending federal legislation threatened to impose a “top-down” transmission expansion planning process on the Eastern Interconnection (EI).

In response, the Planning Authorities (PAs) of the EI, including the NYISO, PJM, ISO-NE and MISO, developed the Eastern Interconnection Planning Collaborative (“EIPC”) under a formal Agreement in mid-2009 to manage the process for (i) performing a coordinated roll-up of existing regional transmission expansion plans and (ii) analyzing the combined system on an interconnection-wide basis. The EIPC process is based upon “bottom-up” planning and is committed to interactive dialogue and open and transparent proceedings.

In December 2009, the DOE announced that it had selected the EIPC and Eastern Interconnection States Planning Council (“EISPC”) proposals for awards to develop an Eastern-interconnection wide planning process. The DOE contract was finalized in August 2010. ISO-NE, NYISO and PJM are supporting the project as Principal Investigators under the DOE contract.

[48] Available online at: http://www.nerc.com/files/2011LTRA_Final.pdf

5.7.2 Structure of the DOE Project

The DOE project is comprised of thirteen separate Tasks broken down into two distinct Phases. Phase I started in early 2010 with the formation of a Stakeholder Steering Committee and included the development of a "Roll-Up Case" for the Eastern Interconnection based upon the existing regional plans of the EIPC Planning Authorities. The SSC then developed a series of eight "energy futures" which represent various potential public policy views. EIPC's consultant, Charles River Associates (CRA), then performed a series of macroeconomic analyses for a total of 80 futures and sensitivity cases in order to develop resource expansion options based upon the SSC's input assumptions. This information was then utilized by the SSC to select three final resource expansion Scenarios for more detailed analysis during Phase II. Phase I culminated in the preparation and filing of an Interim Report with the DOE in December 2011.

Phase II started in January 2012 with the development of transmission build out options to accommodate each of the three Scenarios selected by the SSC. The EIPC Planning Authorities will then conduct a series of power flow and contingency analyses for the year 2030, resulting in a transmission build out for each Scenario that is consistent with NERC's reliability standards. This analysis will focus on bulk power system facilities above 230kv. A Production Cost analysis will be performed for each Scenario, utilizing the transmission build outs developed by the EIPC. The EIPC and its consultants will develop high level cost estimates for the resource and transmission facilities identified in each Scenario. Phase II will conclude in a Final Report which is scheduled to be filed with the DOE in December 2012.

5.7.3 Formation of the Stakeholder Steering Committee (SSC)

EIPC efforts during the first half of 2010 were focused on the development of the Stakeholder Steering Committee and the establishment of its governance process. The SSC is comprised of 29 members from seven sectors with representatives throughout the Eastern Interconnection. The first SSC meeting was held in July 2010 in Chicago at which several Working Groups were formed to advise the SSC during the course of the DOE project.

Northeastern stakeholders from all sectors and regions, as well as the states, have been active participants on the SSC from the beginning.

5.7.4 Summary of Phase I Technical Work

5.7.4.1 Roll-up of Existing Regional Plans, in 10 and 20 Years

As part of its commitment to a "bottom-up" planning process, in September 2010 the EIPC Planning Authorities provided an initial 10-year power flow case, the "2020 Roll-Up", by aggregating the existing regional plans. The reliability analysis of the Roll-Up case found no significant reliability issues. Such a finding is noteworthy as it is indicative of the fact that the respective regional plans are not causing burdens that would manifest themselves as unsolved reliability violations elsewhere in the Eastern Interconnection. The Roll-Up was intended to serve as the basis both for the interregional analysis of the existing regional plans and for the expansion scenarios selected by stakeholders through the Stakeholder Steering Committee (SSC). However, the SSC decided to develop their own criteria for inclusion of future resources for the purpose of the DOE project. The resultant "Stakeholder Specified Infrastructure" was approved by the SSC in early 2011 and was then re-analyzed by the EIPC—with minor adjustments—to provide a solved power flow case which was used as the starting point for the development of the energy futures.

5.7.4.2 Development and Analysis of the Energy Futures

The major SSC activity during Phase I was focused on the development of the eight energy futures and related sensitivity cases—totaling 80 separate cases—for the macroeconomic analysis to develop the associated resource expansion plans. The SSC formed two Working Groups to engage these issues: The Scenario Planning WG advised the SSC on the selection of the energy futures and sensitivities, while the Modeling WG developed detailed input assumptions to be used in the modeling effort for each of these cases. The eight futures that were approved by the SSC are:

1. "Business as Usual" – This Future assumes that present trends continue into the future based on historical indices
2. Federal Carbon Constraint: National Implementation
3. Federal Carbon Constraint: Regional Implementation
4. Aggressive Energy Efficiency, Demand Response, Distributed Generation and Smart Grid
5. National RPS: National Implementation (top down)
6. National RPS: State and Regional Implementation
7. Nuclear Resurgence
8. Combined Federal Climate and Energy Policy Future

CRA then performed macroeconomic analysis using its nation-wide NEEM/MRN models and provided an extensive amount of data for stakeholder review in the development of the final three Scenarios. Detailed spreadsheets and summaries of this information were provided by modeling year (every 5th year) from 2015 through 2040, by region, for the following parameters:

- New capacity builds by type.
- Capacity retirements by type.
- Generation by type of capacity.
- Emissions and emission costs by type of capacity.
- Fuel and O&M costs by type of capacity.
- Capital costs for new capacity builds by type of capacity.
- Energy flows by transfer path.

Table 5-3 lists a summary of the installed capacity in 2030 resulting from each of the energy futures—by resource type—compared with today's existing resources.

Table 5-3: Installed Capacity in 2030 for Each Energy Future Compared with Existing Resources (2010)

Generation Type	Installed Capacity 2010 (GW)	Installed Capacity in 2030 (GW)							
		F1 Base	F2 Hard	F3 Hard	F4 Base	F5 Hard	F6 Hard	F7 Base	F8 OL75
Coal	272	199	31	39	172	179	178	199	10
Nuclear	100	105	131	134	105	105	105	129	134
CC	133	202	226	252	138	166	157	174	208
CT	120	132	112	105	69	140	134	134	66
Steam Oil/Gas	75	36	29	18	3	38	38	34	4
Hydro	45	45	51	52	45	51	52	47	50
On-Shore Wind	19	68	317	197	54	217	159	68	261
Off-Shore Wind	0	2	2	2	2	2	38	2	2
Other Renewables	4	14	13	13	12	13	37	14	12
New HQ/Maritimes	0	0	3	5	0	6	1	0	5
Other	17	17	17	17	17	17	17	17	17
Total w/o DR	783	819	932	833	617	933	916	818	770
DR	33	71	71	71	152	71	71	71	152
Total w/ DR	816	890	1003	903	769	1,003	987	889	923

Table 5-4 shows a comparison of the resource mix of major energy types for each future and the resultant CO2 emission levels.

Table 5-4: Comparison of 2030 Resource Mix, Energy Demand and CO_2 Emissions for Each Energy Future

	EIPC Scenario							
	BAU	F2 Hard	F3 Hard	F4B	F5 Hard	F6 Hard	F7B	F8 OL75
CC	25%	26%	37%	16%	15%	13%	19%	26%
Coal	38%	1%	2%	41%	32%	33%	39%	0%
Nuclear	22%	31%	32%	27%	23%	23%	27%	35%
On-Shore Wind	5%	30%	18%	5%	20%	13%	5%	27%
Off-Shore Wind	0%	0%	0%	0%	0%	4%	0%	0%
Hydro	5%	7%	7%	7%	6%	6%	6%	8%
Total[1]	96%	96%	96%	96%	96%	91%	96%	96%
Demand (TWh)	3,702	3,248	3,248	3,008	3,609	3,609	3,700	3,008
Change from BAU		-12%	-12%	-19%	-3%	-3%	0%	-19%
CO_2 (Million Metric Tons)	1,716	296	408	1,367	1,310	1,316	1,650	264
Change from BAU		-83%	-76%	-20%	-24%	-23%	-4%	-84%

[1] This total represents the major energy sources listed for each case. The remainder includes such resources as oil, biomass, and wood.

To support the SSC in assessing the results of the macroeconomic analysis and reaching consensus on the three (3) future scenarios of interest, the EIPC developed an approach which employs generic, high-level transmission expansion cost estimates for use in comparisons among the macroeconomic scenarios. These generic cost estimates were intended only for use by the SSC in quantifying levels of transmission impacts among the many uncertain future expansion scenarios being considered relative to each other.

Detailed transmission analysis will be conducted for each of the final three scenarios as part of the Phase II analysis.

Table 5-5 provides a summary of the maximum and minimum transmission costs developed for each future.

Table 5-5: High Level Transmission Cost Estimates[49] for Various Energy Futures

Case	Total Miles of Transmission	Cost Estimate Range ($ Billions)	
		Low End	High End
Future 2	10,757	34.1	48.8
Future 3	1,171	1.7	2.7
Future 5	13,613	39.2	58.3
Future 6	650	2.1	3.1
Future 8	11,648	36.7	51.1

5.7.4.3 Selection of the Final Three Scenarios

During the latter part of 2011, the SSC was engaged in reviewing the results of the CRA analyses and developing criteria for the selection of the final three Scenarios. The final three scenarios adopted by the SSC are:

- National Carbon Constraint with Increased Energy Efficiency/Demand Response/Distributed Generation
  - Greatest emission reductions
  - Largest expected inter-regional transmission build-out
- Regionally Implemented National RPS
  - Incorporates a wider variety of policy drivers
  - Lower level of transmission build out
- "Business As Usual"
  - Reference case
  - Significant retirements & new builds
  - Some transmission will be needed within regions

5.7.5 Phase II Activities

5.7.5.1 Development of Procedures for Transmission Build Out & Formation of TOTF

In late 2011, EIPC formed a Working Group to develop the procedures and schedule for the Phase II activities—focusing on the initial transmission build outs and reliability analysis to support each of the three Scenarios developed by the SSC. That process included the formation of a joint committee—the Transmission Options Task Force ("TOTF")—comprised of the EIPC Planning Authorities' technical personnel and stakeholder representatives from each sector to advise the SSC on the selection of transmission options to be considered for each resource expansion Scenario.

[49] These cost estimates are for the "Base Case" for each future – using the stakeholder modeling group analysis of the "soft constraint" runs, which specified the increases in pip flows for each interface that the planning authorities then used to develop these cost estimates. The futures not included in this table were those for which the SSC did not ask for the soft constraint run to be performed.

5.7.5.2 Task 7: Interregional Transmission Options Development

Phase II began in January 2012 with a meeting of the TOTF to discuss development of the power flow models for the three scenarios selected by the SSC and review potential transmission alternatives to support each of the resource futures. Additional meetings and webinars were held during February and March at which the Planning Authorities reviewed the detailed data inputs used for the power flow models—based upon the NEEM analysis from Phase I, provided the initial results of the contingency analysis and discussed potential transmission additions to address those contingencies. Task 7 is scheduled to continue through the beginning of July 2012 and will result in the selection of a set of transmission options for each of the three scenarios.

5.7.5.3 Task 8: Reliability Review

Following selection of the final set of transmission options in Task 7, the Planning Authorities will perform reliability analysis consistent with NERC criteria for each scenario. Adjustments will be made to the transmission options as needed to satisfy the reliability criteria. This Task is scheduled to begin in June and extend through mid-August 2012.

5.7.5.4 Task 9: Production Cost Analysis

Production cost analysis, utilizing the GE MAPS Model, will be performed on the final transmission build outs from Task 8 for each of the three Scenarios. The SSC Modeling Working Group will be reconvened to review the data assumptions and provide guidance as needed. This Task is expected to begin in July and extend through the end of September 2012.

5.7.5.5 Task 10: Generation & Transmission Cost Estimates

The PAs and their consultant will provide high-level estimates of the capital costs of the interregional generation resource and transmission expansion options considered. Transmission costs will be developed using generic planning-type estimates referenced to the study year and will represent "overnight" costs. Costs associated with resource additions and retirements will be informed by SSC assumptions regarding technology characteristics and costs. Task 10 is expected to proceed concurrently with Task 9 and extend through early October 2012.

5.7.5.6 Tasks 10 & 11: Review of Results & Final Report

The PAs will develop a draft Phase II report and provide it for SSC and stakeholder review. The final Phase II Report will be submitted to the DOE in December 2012.

5.8 Fuel Diversity Issues

Fuel diversity is an important aspect in interregional planning. It encompasses the diversity of the energy sources across the entire footprint of the three ISO/RTOs as well as the operational flexibility and coordination among these ISO/RTOs in the case of a temporary fuel supply shortage or disruption. Several factors have encouraged the development of renewable generation projects which would further diversify the supply of fuel. These include the states' Renewable Portfolio Standards and related programs (discussed in Section 7), tax incentives, and environmental regulations. In the future, the growth of renewable resources will play a larger role in diversifying supply-side energy sources. Additionally, energy efficiency measures would reduce the overall fuel consumption throughout the northeast. Table 5-6 shows the energy resource diversity of the each of the three ISO/RTOs for 2010.

Table 5-6: NCSP11 Fuel Diversity 2010 Energy by Fuel Source (GWh & %)

	Nuclear	Coal	Nat Gas*	Oil	Hydro**	Other Ren	Wind	Total
ISO-NE	38,364	14,131	57,579	545	8,080	7,192	491	126,383
	30.4%	11.2%	45.6%	0.4%	6.4%	5.7%	0.4%	100.0%
NYISO	41,870	13,852	52,928	242	25,015	2,917	2,533	139,357
	30.0%	9.9%	38.0%	0.2%	18.0%	2.1%	1.8%	100.0%
PJM	254,534	362,075	86,266	3,243	14,384	5,363	8,813	734,678
	34.6%	49.3%	11.7%	0.4%	2.0%	0.7%	1.2%	100.0%
Total	**334,768**	**390,058**	**196,773**	**4,030**	**47,479**	**15,472**	**11,837**	**1,000,418**
	33.5%	**39.0%**	**19.7%**	**0.4%**	**4.7%**	**1.5%**	**1.2%**	**100.0%**

* Dual fuel (gas and oil) units are included in the natural gas category for NYISO

** Hydro category includes 854 GWh and 801 GWh of pumped storage for the ISO-NE and NYISO service areas, respectively

The table shows relatively similar diversity of fuel supply for both ISO-NE and NYISO with natural gas as the dominant power plant fuel source while PJM's most dominant power plant fuel source is coal. While natural gas-fired generation resources are already dominant within the NYISO and ISO-NE balancing areas, the combined impacts of upcoming environmental regulations and anticipated low natural gas prices will likely lead to natural gas additions within the overall PJM/NYISO/ISO-NE area. Discussions of natural gas issues have been discussed with the IPSAC,[50] and the JIPC will continue to track these issues in the future. By coordinating fuel diversity issues over a wider footprint, the overall risk of fuel supply issues is diminished, increasing system reliability.

5.8.1 New England

Although New England is highly dependent on natural gas as primary fuel for regional power plants, several regional natural gas sector projects have been completed over the last few years that have helped to diversify the sources of natural gas supply that is delivered to the region. Liquefied Natural Gas (LNG) supplies about 20% to 25% of the overall natural gas supply to the region on a peak winter day. In addition to Suez LNG's Distrigas of Massachusetts (DOMAC), the region also has three interconnects to sources of LNG: the Northeast Gateway Deepwater Port offshore of Gloucester, MA, the Canaport LNG import and storage terminal located in Saint John, New Brunswick, and a third LNG import facility, the Suez LNG Neptune Project, which was added in 2010 and is similar to the deepwater port facility located offshore of Gloucester, MA.

In 2011, ISO-NE contracted ICF International (Fairfax, VA) to provide a deterministic assessment of the amount of natural gas supply available to satisfy New England's gas-fired power generation through 2020. The assessment focused on gas supply during peak winter day conditions when the region's total gas demand is highest and peak summer day conditions when electricity demand is highest, but there is relatively low gas demand for other sectors. Additional pipeline capacity into the region was assumed to be built, to provide additional access to Marcellus shale supplies and satisfy regional LDC load growth.

For each year of the projection, the projected net surplus/deficit in regional gas supply remaining after accounting for the total firm (i.e., LDC core loads) and non-firm gas demands was determined. The net

[50] Refer to the following two IPSAC presentations (June 27, 2011): [1] Natural Gas and Power Generation in New England, which can be found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/jun272011/ng_issues.pdf; [2] Northeast Natural Gas Supply & Infrastructure, which can be found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/jun272011/kiley_nga.pdf

surplus/deficit value also considered the amount of additional gas supply needed to deliver operating reserve due to the loss of a 1,200 MW nuclear unit. Projections considered two different power sector scenarios: a reference case that assumes the existing generation fleet continues to operate, and a repowering case that assumes that approximately 7,250 MW of non-gas-fired generation in the region is replaced with new gas-fired generation.

Results of the analysis indicated that while gas supply is projected to be in surplus during summer peak conditions, New England's gas supply capability will be inadequate to satisfy power sector demands during peak winter day conditions by 2020 without incremental expansion of the regional gas delivery system or the use of alternative fuels in dual-fuel generators. This deficiency would be further exacerbated if significant repowering with gas-fired generation occurred in the region.

5.8.2 New York ISO

The New York electric system relies on supply from many fuel sources. While there is no industry standard for determining what exactly constitutes "fuel diversity", New York State's overall electric system is relatively diverse in comparison to many other areas. In the past decade, many new power plants added rely on natural gas to generate electricity. Units burning natural gas (including dual fuel) made up 38% of the total energy generation in New York State in 2010, emphasizing the importance of studying the potential impact of the natural gas system on the electric system.

In 2002-03, Levitan & Associates, Inc. (LAI) performed a resource assessment study of pipeline deliverability to serve the coincident natural gas requirements of power generators and local distribution companies (LDCs) in the greater Northeast. Since the Multi-Region Gas Study was completed in 2003, several significant infrastructure projects have been proposed and/or completed in and around the New York Control Area (NYCA). The majority of these pipeline and storage facility improvements reflect the need to modify traditional supply pathways into the market center in response to changing production profiles from western Canada, the Gulf Coast, and, more recently, from the Rocky Mountains. Several new pipeline supply expansion projects have been formulated by incumbent pipelines serving New York State in response to abundant natural gas reserves in the Marcellus Shale formation in Pennsylvania, West Virginia and New York.

In the 2010 pipeline infrastructure assessment, LAI expanded on prior research conducted for NYISO. The goals and objectives were fourfold: first, to delineate the new and proposed pipeline projects and facility improvements affecting natural gas infrastructure and deliverability across NYCA; second, to identify the expected natural gas requirements of gas-fired generators in NYISO on a peak electric day, that is, during the peak cooling season; third, to postulate gas-side contingency events that would seriously impair natural gas service to generators in NYISO, including gas-fired generators behind the citygate on the New York Facilities System (NYFS); and, fourth, to quantify an upper limit of gas-fired generation deemed at-risk in the event such low probability/high impact gas-side contingencies were to occur during the peak cooling season.

New York City and Long Island are required by the New York State Reliability Council (NYSRC) Local Reliability Rules I-R3 and I-R5 to be operated so that the loss of a single gas facility does not result in the loss of electric load on their respective systems. Periodic assessments are performed by the Transmission Owners and reviewed by the NYISO and NYSRC to ensure compliance with these rules. One potential upstate gas-side contingency was studied in the NYISO 2010 Comprehensive Area Transmission Review which indicated no Bulk Power Transmission Facilities (BPTF) security violations.

5.8.3 PJM

PJM has a relatively diversified mix of available fuel supplies for its generation capacity. PJM's main sources of energy are coal and nuclear fuels, comprising almost 85% of the total PJM generation on an energy basis. The balance of the supply is natural gas, hydro, wind and miscellaneous other sources. Any long-term disruption of fuel supplies would be expected to cause a natural market shift to the remaining available sources. Given this mix of available fuel sources, PJM has options and market flexibility to compensate for the exposure of a fuel source disruption. PJM could be economically exposed to the retirement of older coal-fired generation in a scenario involving major cost increases due to environmental regulations. This could cause some coal-fired generation to become less competitive. In the near term, however, PJM has new and robust supplies of gas, and in the longer term, is within the geographic footprint of the Marcellus Shale natural gas field, a major new supply source that could produce competitive natural gas supply for years.[51] Coupled with the ongoing development of wind energy in PJM, and the ability to mitigate shorter term disruptions, resource fuel issues are a low level concern for PJM. If recent trends away from coal and toward gas supply continue or accelerate, then gas supply issues and transmission reliability issues will receive increased planning attention. While these trends could cause significant changes to the power system, PJM anticipates being able to manage anticipated reliability challenges. The likely increased dependence on gas supply is an important driver of PJM's participation with NYISO and ISO-NE in the proposed Gas/Electric study described in Section 11.4.

5.9 Summary

Interregional planning is becoming increasingly proactive as shown by studies of broad areas that seek to solve problems over multiple systems. The numerous planning activities discussed in this section demonstrate that planning is coordinated among the Northeastern ISO/RTOs and with neighboring systems. NPCC continues to promote and participate fully in proposed joint studies with its neighboring regional reliability council, RFC. These studies assess the mutual interactions of the high voltage transmission systems of both regions as planned for the future, with particular emphasis on major planned transmission additions and interregional power transfer capabilities. The IRC has promoted an open and reliable planning process. In addition, ERAG studies examine interregional studies over a wide geographic footprint and the EIPC offers a forum for conducting interconnection-wide planning. The three ISO/RTOs have fully coordinated their operations and planning to address fuel diversity issues. The three ISO/RTOs will continue participation in the forums summarized in this report and others to ensure a reliable and efficient bulk electric system in upcoming years.

6 Key Environmental Issues with Potential Interregional Impacts

The environmental regulatory impacts summarized in this section reflect the status of the subject regulations with regard to stage of development or phase of implementation. In addition, many of the environmental regulations summarized entail facility specific implementation by local permitting authorities resulting in specifically tailored compliance obligations that cannot be readily generalized into interregional impacts. The JIPC will continue to track and report on the cumulative impacts of environmental regulations when such information becomes available.

6.1 Regulatory Updates

The Environmental Protection Agency (EPA) is in the process of finalizing a suite of environmental regulations under the *Clean Air Act*, the *Clean Water Act*, and the *Resource Conservation and Recovery*

[51] For more information on shale gas and other natural gas supplies, see http://www.interiso.com/public/meeting/20091218/20091218_northeast_natural_gas_system_update.pdf

Act that will particularly impact existing coal- and oil/gas-fired steam generators across the Northeast. This suite of EPA regulations may require significant retrofit capital costs for environmental compliance, restrict operation, and result in retirements of generators between 2012 and 2020.

ISO-NE estimates these regulations affect over 12.1 GW of installed capacity across New England. NYISO estimates 23,847 MW of capacity will be affected in NY and PJM estimates up to 25 GW of capacity will be affected. In some cases, this will entail significant capital investment for retrofitting facilities with post-combustion control devices, closed-cycle cooling systems, or fuel-switching equipment, or retiring generators.

The *Cross-State Air Pollution Rule* (CSAPR) was finalized on July 6, 2011, and subsequently stayed on December 30, 2012. The *Mercury and Air Toxics Standards* rule was published on February 16, 2012 and takes effect on April 16, 2012, and the *Cooling Water Intake § 316(b) Rule* is scheduled to be finalized by July 27, 2012. These rules were required to be finalized by EPA according to various court orders and implemented between January 2012 and January 2016.[52] Table 6-1 summarizes the new and upcoming environmental regulations, their targeted pollutants, and likely control technologies considered most suitable on the basis of available information.

[52] Various court orders require several upcoming EPA rulemakings: *Clean Air Transport Rule* (North Carolina v. EPA, 531 F3.d 896 (D.C. Cir. 2008) (revoking *CAIR)*, North Carolina v. EPA, 550 F.3d 1176 (D.C. Cir. 2008) (remanding CAIR, ordering development of *CATR*)); *Air Toxics Rule* (New Jersey v. EPA, 517 F.3d 574 (D.C. Cir. 2008) (revoking *Clean Air Mercury Rule* (*CAMR*), *American Nurses Association v. Jackson*, No. 08-2198 (D.D.C. 2010) (setting rulemaking schedule)); *Cooling Water Intake Rule* (Riverkeeper, Inc. v. Jackson, 93 Civ. 0314 (S.D.N.Y 2010) (setting rulemaking schedule).

Table 6-1: New and Upcoming EPA Environmental Regulations

Proposed EPA Regulation	Targeted Pollutant or Impact	Control Options
Clean Air Act § 112 **Mercury and Air Toxics Standards Rule**	Hazardous air pollutants (mercury (Hg), HCI, HF, metals, organics)	Hg removal: fabric-filter baghouse (FF), activated carbon Injection (ACI) 80-90%; scrubber- selective catalytic reduction (SCR) co-benefit >90%[(a)] Wet or dry FGD, dry sorbent injection and fuel switching.
Clean Air Act § 110(a)(2)(D)(i)(I) **Cross-State Air Pollution Rule**	Reduce contribution to ozone and PM2.5 nonattainment in downwind nonattainment areas.	NO_x removal: SCR 70-95%; selective non-catalytic reduction (SNCR) 30-75%[(b, c)]
Proposed as Clean Air Transport Rule (CATR)		SO_2 removal: scrubber ≥95%; dry sorbent injection <70%
Resource Conservation & Recovery Act **Coal Combustion Residue Rule (Coal Ash)**	Coal combustion waste disposal	Phase out wet-surface impoundments (ash ponds); composite liners; other design requirements for disposal sites or unit retirements
Clean Water Act § 316(b) Cooling Water and Wastewater Rule	Cooling water intake impacts	Intake design upgrades: cooling water intake structure retrofits; closed cycle cooling towers.
	Waste water toxic metals	Treatment or zero discharge

[(a)] Fabric-filter collection system, or baghouse, is a post-combustion particulate control system that traps particles in cylindrical or square filter elements, which are periodically cleaned to remove trapped particles.
[(b)] Selective catalytic reduction (SCR) is a post-combustion NOX control technology that treats flue gas with ammonia (NH3) as it enters a catalyst reactor. NH3 reacts with NOX, removing greater than 90% under optimal conditions .
[(c)] Selective noncatalyticnon-catalytic reduction (SNCR) is a post-combustion NOX control technology that treats flue gas with ammonia or urea and can remove greater than 30% of NOX in the flue gas under optimal conditions in a temperature range between 1,800 and 2,000°F.

The final Mercury and Air Toxics Standards (MATS) affects coal- and oil-fired steam units over 25 MW, CSAPR affects all fossil fuel-fired units over 25 MW in the eastern half of the United States and includes Texas, Kansas, and Nebraska. The proposed Coal Ash rule affects waste disposal sites receiving combustion wastes from coal-fired units nationwide, while the potential *Cooling Water Intake § 316(b)* rule could affect cooling water intake structures at steam thermal generating stations, whether fossil fuel-fired or nuclear powered, with a cooling water design intake over 2 million gallons per day.

6.1.1 Clean Water Act

Many existing cooling water intake structures (CWIS) serving thermal electric generating stations (coal-, oil/gas-fired and nuclear) are equipped with once through cooling systems that can withdraw billions of gallons per day from waterways across the Northeast. Cooling water withdrawals for thermal electric generating stations may adversely impact aquatic ecosystems by also removing aquatic organisms, including juvenile fish and shellfish and through thermal pollution of cooling water discharged into affected waterways which may also contribute to aquatic mortality. Figure 6-1 depicts the ways that

CWISs can affect aquatic organisms. EPA developed national standards under the National Pollution Discharge Elimination System (NPDES) for implementation of Best Technology Available (BTA) to reduce aquatic mortality at new and existing cooling water intake structures (CWIS) equipped with once through cooling systems serving thermal power plants, but those earlier efforts were deemed inadequate according to litigation challenging those regulations.

The proposed changes in cooling water intake requirements for CWIS serving thermal power plants under the *Clean Water Act § 316(b)* potentially could require retrofit of closed-cycle cooling systems (natural or mechanical draft cooling towers) at CWIS serving some thermal power plants in the region.[53] The proposed revised requirements would result in fewer aquatic organisms being impinged (trapped) against exterior portions of the CWIS or entrained (drawn into the cooling systems). In earlier rulemakings and various court decisions, EPA established that impingement and entrainment of aquatic life are the principal adverse impacts of CWIS serving thermal electric generating facilities.

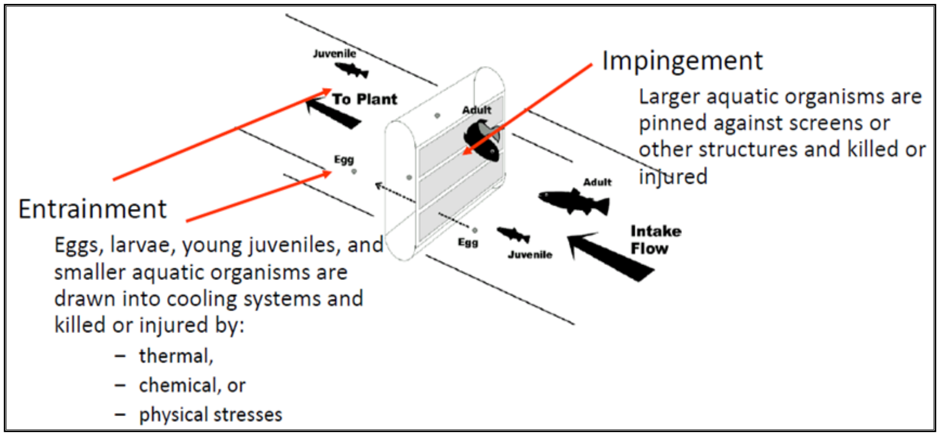

Figure 6-1. Depiction of ways cooling water intake structures affect aquatic organisms[54]

On April 20, 2011, partly in response to litigation challenging the adequacy of prior regulation and pursuant to the requirements of the *Clean Water Act § 316(b)*, the EPA proposed revised national standards for minimizing adverse environmental impacts in the location, design, construction, and capacity of CWIS at existing thermal electric generating facilities. Existing facilities subject to the proposed cooling water rule include:

- Equipped with CWIS withdrawing waters of the United States (ocean, tidal, lake or estuary);
- Have a total CWIS design intake flow of greater than 2 million gallons per day (MGD);
- Exclusively using at least 25% of the water withdrawn for cooling purposes measured on an average annual basis for each calendar year.[55]

EPA must finalize the proposed *Cooling Water Intake § 316(b)* rule by July 2012 according to a consent decree. Once finalized, depending on site-specific circumstances, affected electric generating facilities served by CWIS equipped with once-through cooling would have to develop compliance plans and possibly install closed cycle cooling systems or effective alternative technologies. The compliance

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[53] U.S. EPA, Cooling Water Intake Structures Regulation under Clean Water Act 316(b), see http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm for more information

[54] Ira Leighton, USEPA, and EPA Air & Water Rules for Power Plants (June 17, 2011), EBC Energy Program: Converging EPA Air and Water Rules for Power Plants -*The Evolving Shape of Electric Generation conference*.

[55] U.S. EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 22174, 22192 (April 20, 2011).

demonstration process would begin shortly after the rule becomes effective, and depending upon site specific situations, the compliance period may extend up to eight years (i.e., until July 2020).

The proposed *Cooling Water Intake § 316(b)* rule preferred entrainment mitigation option (Option 1) requires electric power generating facilities consuming more than 125 million gallons per day of once through cooling water to prepare and submit an entrainment characterization study, to determine whether they would be required to retrofit closed cycle cooling systems. If Option 1 is adopted by EPA in the final Cooling Water Intake § 316(b) rule for entrainment mitigation, total compliance costs are expected to be lower, but many power generating facilities in New England may be required retrofit closed cycle cooling systems. Table 6-2 lists the impingement and entrainment mitigation control requirements for both existing facilities and new units at existing facilities in the NPCC area, as well as estimated annual compliance costs, for the four control options assessed by EPA as part of the proposed *Cooling Water Intake § 316(b)* rule.

Table 6-2: EPA Proposed *Cooling Water Intake § 316(b) Control Options and Costs in NPCC*[(a)]

Option	Impingement and Entrainment Mitigation Control Requirements		Estimated Annual Compliance Costs ($ Millions, 2009)[(b)]
	Existing Facilities	New Units at Existing Facilities	
1	• Uniform impingement mortality controls • Site-specific entrainment controls for design intake flow rates (DIF) (withdrawal) over 2 million gallons per day (MGD) • Site specific determination of Best Technology Available for entrainment at facilities with greater than 125 MGD actual intake flow	Uniform entrainment controls	51.6
2	• Impingement mortality controls at existing facilities that withdraw over 2 MGD (DIF) • Flow reduction equal to closed-cycle cooling at facilities with DIF of over 125 MGD	Flow reduction equal to closed cycle cooling	744.7
3	• Impingement mortality controls at existing facilities that withdraw over 2 MGD (DIF) • Flow reduction commensurate with closed-cycle cooling at all existing facilities with DIF over 2 MGD	Same requirements as existing facilitites	791.2
4	• Uniform impingement mortality controls at existing facilities that withdraw 50 MGD or more (DIF) • Best professional judgment permits for existing facilities with design intake flow between 2 MGD and 50 MGD (DIF)	Uniform entrainment controls	51.2

Sources: [(a)] *US EPA, National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities,* Proposed Rule, 76 Fed.Reg. 22174, 22204-22206 (April 20, 2011). Exhibit VII-11, Compliance Cost per Unit of Electricity Sales in 2015 by Regulatory Option and NERC Region, p. 22228, 22229.
[(b)] EPA estimated annual pre-tax compliance costs (2009 $) for known affected *§ 316(b)* in NPCC region.

Under the preferred Option 1 in the proposed *Cooling Water Intake § 316(b)* rule, existing facilities with a design intake of greater than 125 MGD would have the additional requirement to submit entrainment mortality characterization studies and detailed engineering assessments of entrainment technology control options to the local permitting authority.

Using such information, the local permitting authority would make a site-specific determination of what constitutes the best technology available (BTA) for minimizing adverse environmental impacts under the *Clean Water Act § 316(b)*, if any, for entrainment mitigation, including installation of closed-cycle cooling systems equipped with natural or mechanical draft cooling towers. Local permitting authorities would determine site-specific entrainment BTA controls balancing the following mitigating factors:

- Local energy reliability concerns should be considered;
- Increased air emissions associated with construction of closed cycle CWIS at fossil fuel-fired facilities;
- Land availability, noise abatement and local setback restrictions may preclude construction of closed cycle CWIS at a minority of existing electric generating facilities;
- Given the long lead times required in planning, designing, and constructing closed cycle CWIS, EPA proposes local permitting authorities be given latitude in considering the remaining useful plant life in establishing site-specific entrainment standards.

Entrainment compliance costs, particularly retrofitting closed loop CWIS at existing electric generating facilities are expected to constitute the majority of the anticipated compliance costs.

6.1.1.1 § 316(b) Cooling Water Rule Impact in PJM

In preparation for implementation of the proposed Cooling Water § 316(b) Rule, PJM has inventoried existing steam thermal station cooling systems at the unit level. PJM believes that the State permitting authorities appear to have adequate time and resources under the proposed Cooling Water § 316(b) Rule to determine appropriateness of compliance solutions, which is expected to have moderate impacts within the PJM footprint. Also, the length of the implementation period (up to 8 years) provides additional time for analysis by both generators and PJM. At this time, PJM has not been notified by generation owners of any potential unit retirements due to the forthcoming Cooling Water Rule.

6.1.1.2 § 316(b) Cooling Water Rule Impact in New York

The New York Department of Environmental Conservation adopted a policy for determining the Best Technology Available (BTA) for Cooling Water Intake Structures in July 2011. New York power plants with open cycle cooling systems will need to conduct studies and demonstrate that their systems can be modified to achieve reductions in aquatic impacts equivalent to 90% of the reductions that could be achieved by the use of a closed cycle cooling system, e.g., using cooling towers. This policy is activated upon renewal of a plant’s water withdrawal and discharge permit. Based upon a review of current information available from NYSDEC, NYISO has estimated that between 4,000-7,000 MW of capacity could be required to retrofit closed cycle cooling systems. The most publically recognized application of this policy is the Indian Point nuclear power plant.

6.1.1.3 § 316(b) Cooling Water Rule Impact in New England

EPA estimates that cooling water intake structures serving 30 existing electric generating facilities in New England are subject to the proposed *Cooling Water Intake § 316(b)* rule.[56] Under the EPA preferred Option 1 in the proposed *Cooling Water Intake § 316(b)* rule, 12.1 GW of installed capacity in New England would be required to upgrade mortality impingement control technologies if they did not already have modified coarse mesh traveling screens installed or equivalent impingement mortality control

[56] US EPA, *National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities*, Proposed Rule, 76 Fed.Reg. 24976, 22174, 22214 (April 20, 2011). EPA concluded that modified Ristroph (or equivalent) coarse mesh traveling screens are the most appropriate basis for determining compliance costs, but this does not preclude the use of other impingement mortality control technologies or by reducing the maximum intake velocity to less than 0.5 feet per second.

technologies.[57] These affected facilities would be required to adopt, measures for reducing the entrapment of aquatic life against the outside surfaces of CWIS or screening devices.

A subset of the 12.1GW of affected capacity in New England equipped with CWIS have design intake flows ranging between 3.2 and 2,059 MGD, there is approximately 5.6 GW of installed capacity located at power generation facilities equipped with CWIS with a design intake greater than 125 MGD.

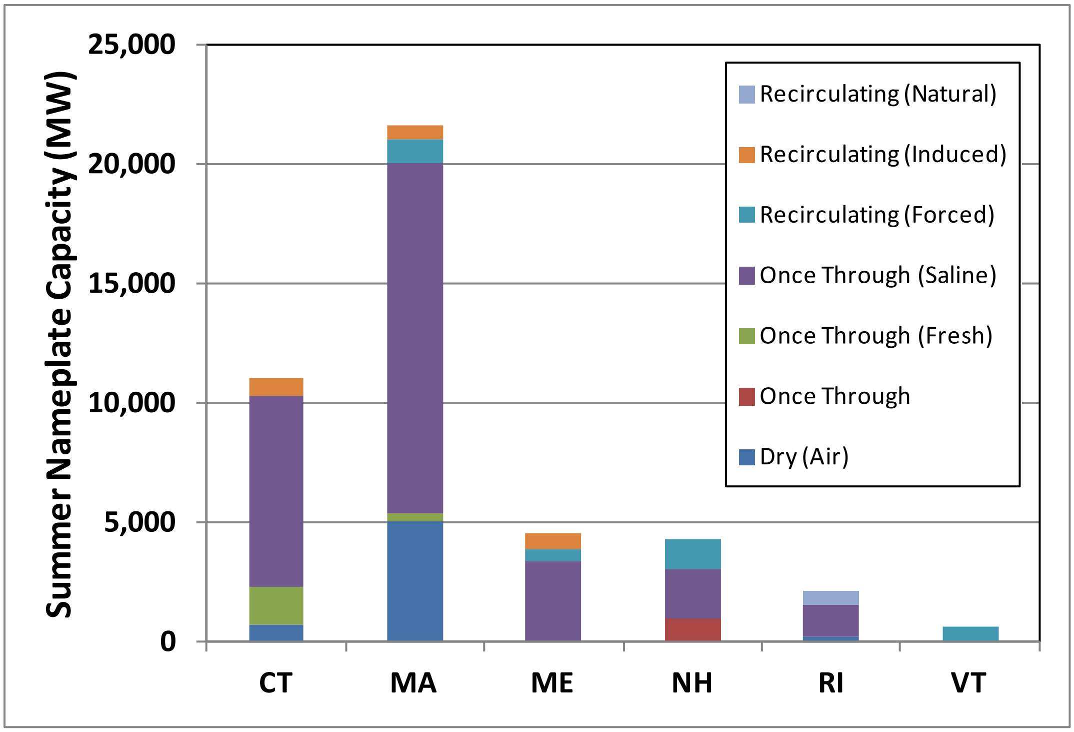

Figure 6-2: Installed Cooling Technology at New England Generators (2010)[58]

This latter group would have the additional requirement of submitting an entrainment characterization study to determine whether closed-cycle cooling would be required at these facilities.[59] Figure 6-2 shows the affected capacity by fuel type and state served by a CWIS.[60]

In New England, a generator served by CWIS equipped with once-through cooling is nearing completion of a retrofit to a closed cycle system featuring a pair of natural draft cooling towers at an estimated total

[57] "EPA notes that in a number of areas of the country (California, Delaware, New York and New England), permitting authorities have already required or are considering requiring existing facilities to install closed-cycle cooling operations." EPA *proposed Cooling Water Rule* 76 Fed.Reg. at 22210.

[58] Energy Information Administration, Form EIA-860 Annual Electric Generator Report (November 30, 2011), available at http://www.eia.gov/cneaf/electricity/page/eia860.html

[59] In New England, Connecticut, Maine, (except for facilities located in sovereign Indian nations), Rhode Island and Vermont have delegated authority to issue NPDES permits under the federal Clean Water Act. Massachusetts and New Hampshire are non-delegated states and issue joint NPDES permits to affected facilities in collaboration with EPA Region 1.

[60] Using closed-cycle cooling water intake estimated capital costs from NERC's *2010 Special Reliability Scenario Assessment: Resource Adequacy of Potential U.S. Environmental Regulations*, EPA technical support documentation for the proposed 316(b) Cooling Water Rule, and reported closed-cycle cooling water intake structure retrofits in New England. EPA notes that in permitting authorities in California, Delaware, New York, and the New England States already have required or are considering requiring existing facilities to install closed-cycle cooling operations. *EPA proposed Cooling Water Rule*, 76 Fed.Reg. 22174, 22210.

capital cost of $630 million or $440/KW. Another generator served by CWIS equipped with once-through cooling received a draft NPDES permit proposing retrofit of a closed cycle cooling system utilizing a mechanical draft cooling tower.[61] The latter draft NPDES permit is not expected to be finalized until late 2012.

ISO-NE estimates that approximately 1-3 GW of the existing 5.6 GW of affected capacity subject to the additional entrainment mitigation requirements under Option 1 may retire between 2018 and 2020, rather than retrofit existing CWIS to closed cycle cooling systems.

6.1.2 Mercury and Air Toxics Standards

On February 16, 2012, final national emission standards for hazardous air pollutants (NESHAP) for mercury and other air toxics emissions from coal- and oil-fired generators greater than 25 MW nameplate capacity under the *CAA§ 112(d)* and revised new source performance standards (NSPS) for fossil-fuel-fired electric generating units under the *CAA § 111(b)* were published in the Federal Register and take effect on April 16, 2012.[62] Under the *CAA§ 112(d)* the final Mercury and Air Toxics Standards (MATS) takes effect three years after the effective date, which is 60 days after publication in the Federal Register. The compliance deadline for the majority of affected generators is April 16, 2015.

MATS requires existing and new coal- and oil-fired electric generating units to limit emissions of acid gases, mercury (Hg), and other heavy metals. MATS requires compliance with numerical emission limits for Hg, particulate matter (PM), HCl, and HF as surrogates for the larger group of hazardous air pollutants that must be controlled under the *CAA § 112(d)*.[63] Table 6-3 lists the final standards, primary control options, and secondary control device co-benefits associated with MATS compliance.

[61] EPA Region I NPDES Water Permit Program; See: http://www.epa.gov/region1/npdes/index.html

[62] U.S. EPA, *National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Final Rule*, 77 Fed.Reg. 9304 (February 16, 2012).

[63] MATS includes alternative emission standards with specific limits for: SO_2; total non-Hg metals; antimony (Sb); arsenic (As); beryllium (Be); cadmium (Cd); chromium (Cr); cobalt (Co); lead (Pb); manganese (Mn); mercury (Hg); nickel (Ni); selenium (Se).

Table 6-3: *Utility Mercury and Air Toxics Standards* Emissions Limits,[64] Control Technology Options

Unit Type	Mercury (Hg) Limit	Hydrogen Chloride (HCl)	Filterable Particulate Matter (PM)
Existing not low rank virgin coal	1.2 lb/Tbtu (0.013 lb/GWh)	0.002 lb/MMBtu	0.03 lb/MMBtu
Existing low rank virgin coal	11 lb/Tbtu (0.12 lb/GWh)	0.002 lb/MMBtu	0.03 lb/MMBtu
Existing IGCC	2.5 lb/Tbtu (0.0002 lb/GWh) [new not low rank coal]	0.0005 lb/MMBtu	0.04 lb/MMBtu
New unit firing not low rank virgin coal	0.0002 lb/GWh	0.0004 lb/MWh	0.007 lb/MWh
New unit firing low rank virgin coal	0.04 lb/GWh	0.0004 lb/MWh	0.007 lb/MWh
Primary Control Options	Activated carbon injection (ACI)(a):	Wet flue gas desulphurization (FGD):(b) Dry FGD:(c)Dry sorben injection (DSI):(d)	Electrostatic precipitator (ESP)(e); Fabric filter baghouse (FF)(f);
Secondary Control Device Co-Benefits		Wet FGD: •Greatest SO_2 capture; •High oxidized Hg capture; •Medium PM capture; Dry FGD: •High SO_2 (>95%), Hg capture; •Some PM capture; DSI: •High SO_2 (40-90%), enhances Hg capture;	ESP: •Capture particulate bound Hg; FF: •High Hg other HAPs capture;
Unit Type	**Hydrogen Fluoride (HF)**	**Hydrogen Chloride (HCl)**	**Filterable Particulate Matter (PM)**
Existing Liquid Oil	0.0004 lb/MMBtu	0.002 lb/MMBtu	0.03 lb/MMBtu
New Liquid Oil	0.0004 lb/MWh	0.0004 lb/MWh	0.07 lb/MWh
Primary Control Options	Wet flue gas desulphurization (FGD):(b) Dry FGD:(c) Dry sorben injection (DSI):(d)		Electrostatic precipitator (ESP)(e); Fabric filter baghouse (FF)(f);

[(a)] Activated carbon injection, a post-combustion mercury control system that injects pulverized activated carbon, sometimes treated with a halogen to enhance capture, into the flue gas where it reacts with gaseous ionic or elemental mercury to form particle bound mercury that can be removed by a downstream PM control device (ESP or FF).

[(b)] Wet flue gas desulfurization is a post-combustion SO_2 control system that injects a lime or limestone slurry into a large absorber vessel where it reacts with SO_2 in the flue gas, removing > 98% under optimal conditions.

[(c)] Dry flue gas desulfurization is a post-combustion SO_2 control system that injects a hydrated lime and water into a large absorber vessel where it reacts with SO_2 in the flue gas, removing > 90% under optimal conditions

[(d)] Dry sorbent injection removes acid gases and SO_2 by injecting a dry sorbent reagent into the flue which reacts with such pollutants and the reaction products are then removed by a downstream particulate control device (FF or ESP).

[(e)] Electrostatic precipitator, a post-combustion particulate control system that uses an electrical charge to separate the particles from flue gas by imparting them with a positive or negative charge and attracting them to a opposite charged surface and then removing them from the collection surface into a hopper by vibrating or rapping the collection surface.

[(f)] Fabric-filter collection system, or baghouse, is a post-combustion particulate control system that traps particles in cylindrical or square filter elements, which are periodically cleaned to remove trapped particles.

Sources: EPA, *Electric Generating Units New Source Performance Standards, Multi-pollutant, SO2, NOx, PM Emission Control Options* (EPA-HQ-OAR-2011-0044) (March 2011); Northeast States for Coordinated Air Use Management, *Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-fired Power Plants* (March 2011); URS Corporation, *Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants* (April 2011).

[64] U.S. EPA, *Final MATS*, 77 Fed.Reg. 9304, 9367-9368 (February 16, 2012). Table 3 Emission Limitations for Coal-fired and Solid Oil-Derived Fuel-fired EGUs.

Many specific air pollution control technology options currently expected to be retrofitted for MATS compliance by affected coal- and oil-fired generators have both primary and secondary co-benefit emission reduction benefits as outlined in Table 6-3. Many MATS affected generators were expected to retrofit air pollution control devices to comply with other regulations, including CSAPR, between 2012 and 2014, ahead of the MATS compliance deadline in 2015.

Under MATS, existing coal- and oil-fired electric generators generally have three years to comply with the applicable air toxics emissions limits.[65] An additional (fourth) year to comply may be granted by the local (state) permitting authority on a case-by-case basis when "necessary" for the installation of controls.[66] Potential compliance options include significant additional capital expenditures for required environmental retrofits. Table 6-4 lists possible control technology configurations for MATS compliance.

Table 6-4: Possible Control Technology Configurations for MATS Compliance and Estimated Capital Costs

Fuel Type	Potential Control Option Configuration	Estimated Capital Cost ($/kW)
Bituminous	• Wet Flue Gas Desulfurization (FGD) + Electrostatic Precipitator (ESP) • Dry FGD + Activated Carbon Injection (ACI) + Fabric Filter baghouse (FF) • Dry Sorbent Injection (DSI) + ACI + FF	Mercury: ACI: $2-10/kW Acid Gases: Wet FGD: $500/kW Dry FGD: $420/kW FGD Upgrade: $50-100/kW DSI:$5-10/kW Particulate Matter: FF Upgrade: $75-130/kW ESP Upgrade: $2-20/kW
Sub-bituminous	• Wet FGD + ESP • Dry FGD + ACI + FF • DSI + ACI + FF	
Lignite	• Wet FGD + ESP + SCR • Dry FGD + ACI + FF + SCR • DSI + ACI + FF + SCR	
Residual Oil	• Wet FGD + ESP • Dry FGD + FF • DSI + FF	

Sources: EPA, Electric Generating Units New Source Performance Standards, Multi-pollutant, SO_2, NO_x, PM Emission Control Options (EPA-HQ-OAR-2011-0044) (March 2011); Northeast States for Coordinated Air Use Management, Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-fired Power Plants (March 2011); URS Corporation, Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants (April 2011).

Many of the expected air pollution control device retrofit projects will need to be staged over successive outage seasons, spanning multiple years at an individual facility, affecting both individual generator availability and retrofit capital costs. There is uncertainty associated with the capital costs for air pollution control devices anticipated to be retrofit by affected generators between 2012 and 2015. The average capital cost ranges provided in Table 6-4 do not include expected additional costs expected with competing demand for materials and labor at multiple air pollution control retrofit projects across the Northeast through successive outage cycles up to the MATS compliance deadline in 2015.

[65] The compliance deadline is April 16, 2015, but an additional year may be granted by the permitting authority upon petition by the affected generator.

[66] According to EPA, state permitting authorities have discretion to grant an additional 4th year for MATS compliance at an affected facility necessary for "the installation of controls" under 112(i)(3)(B), which is interpreted by EPA to include the following scenarios: (1)Construction of replacement capacity onsite of retiring unit; (2)Continued generation from existing unit required during outage of other units being retrofit; (3)Construction of necessary transmission upgrades; (4)Construction of replacement capacity offsite. See Final MATS, 77 Fed.Reg. 9304, 9410 (February 16, 2012)

6.1.2.1 Joint ISO/RTO Proposed "Reliability Safety Valve"

During the comment period for the proposed MATS rule a number of ISO/RTOs (NYISO, PJM, MISO, SPP and ERCOT) proposed a "Reliability Safety Valve," a process by which generators that are needed to maintain reliability of the bulk power grid would be allowed to operate beyond the MATS compliance date until a reliability solution was put in place. Under the Reliability Safety Valve, the Planning Coordinator would receive early notification (approximately one year after the rule is effective) of a generator's plan to comply with the rule, which could include retiring, retrofitting or repowering. In turn, the generator, should it be needed for reliability would be allowed to operate without complying with the MATS rule and not be penalized by the EPA. This is intended to provide adequate time to implement needed reliability solutions, which could be transmission related, demand response, energy efficiency, or generation.

Seeking to partly address the concerns raised in the Joint ISO/RTO "Reliability Safety Valve" proposal, EPA released along with MATS, an Enforcement Response Memorandum outlining options for obtaining additional time for pollution control retrofits, explaining when "there is a conflict between timely compliance with a particular requirement and electric reliability, EPA intends to carefully exercise its authorities to ensure compliance with environmental standards while addressing genuine risks to reliability in a manner that protects public health and welfare."[67] A Presidential Memorandum also released with MATS instructs EPA, DOE and FERC to coordinate and plan the implementation of MATS in order to minimize impacts on system reliability.[68] While the EPA Enforcement Response memorandum appears to grow out of the Joint ISO/RTO "Reliability Safety Valve" proposal, it differs significantly in the detail and flexibility it provides for ensuring system reliability.

A generator seeking to obtain an administrative order granting additional time (5th year) for implementation of reliability solutions will need to request additional time ahead of retirement notice requirements under applicable tariffs. Under MATS, EPA, with input from other stakeholders has the authority to determine whether a unit is reliability critical and eligible for additional time to implement reliability solutions. In regions served by an RTO, EPA would rely on the reliability analysis performed by the RTO, with potential input from FERC and others. It is expected that EPA will negotiate an administrative order granting additional time when there is a "delay due to factors beyond the control of the owner/operator."

In a related matter, FERC declined to convene a joint reliability board with the South Carolina Public Service Commission (SPSC) "to study the impact of regulations of the Environmental Protection Agency (EPA) on the reliability and affordability of electric power in the State of Carolina."[69] In its petition to FERC requesting the joint reliability board, SPSC proposed expanding its scope and inviting other States to participate. FERC did agree to establish joint forums with the National Association of Regulatory Utility Commission (NARUC) to evaluate the impact of MATS and other EPA regulations on system reliability. Subsequent to the first FERC/NARUC Forum, NARUC established the Environmental

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[67] U.S. EPA, Office of Enforcement and Compliance Assurance, *EPA's Enforcement Response Policy For Use of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability and The Mercury and Air Toxics Standard* (December 16, 2011) See http://www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf

[68] Presidential Memorandum, Flexible Implementation of the Mercury and Air Toxics Standards Rule (December 21, 2011) See http://www.whitehouse.gov/the-press-office/2011/12/21/presidential-memorandum-flexible-implementation-mercury-and-air-toxics-s

[69] FERC, 138 FERC ¶ 61,040, Order on Petition of the Public Service Commission of South Carolina and the South Carolina Office of Regulatory Staff, Docket No. EL11-62-000 (Issued January 19, 2012). Petition of Public Service Commission of South Carolina and the South Carolina Office of Regulatory Staff for Creation of a Joint Federal-State Board to Study Electric Reliability. See http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12868819.

Regulation-Generation Task Force to address new environmental rulemakings and its impacts on electric grid reliability.[70]

FERC released a Staff Whitepaper on January 30, 2012,[71] that describes a process by which they would provide input to EPA regarding the 5th year extensions through Administrative Orders. FERC also sought comments on this process. The ISO/RTO Council (IRC) provided comments[72] on February 29, 2012, that were supportive of FERC's proactive approach to addressing FERC's role in the EPA Enforcement Policy process. The IRC believes that to maximize the benefit of the Enforcement Policy process, input into the process must be efficient. As well, leveraging existing processes to evaluate the need for generators employed by ISO and RTO Planning Authorities and FERC's oversight capability can provide reliability information to EPA needed to support EPA's Enforcement Policy process. IRC commented that FERC should review the substantive analyses of the Planning Authorities to provide a "check" on such reliability analyses; FERC should not conduct a de novo review. In addition, the IRC contends that FERC not limit its review solely based on NERC standards, because a strict application of NERC standards as was described in the white paper may not reflect all of the reliability benchmarks/metrics for assessing reliability impacts.

6.1.2.2 MATS Impact in PJM

PJM is estimating approximately 11,000 MW of coal-fired capacity is at high risk for retirement, and another 14,000 MW at risk for retirement due to MATS and CSAPR. Despite this level of retirements, PJM anticipates resource adequacy over the entire RTO will be maintained.

Retirements may pose local reliability issues requiring reliability solutions (transmission upgrades, demand response, energy efficiency, or generation) to ensure transmission and operating reliability. Developing and implementing timely reliability solutions will require coordinated efforts between the various stakeholders, such as PJM, its members, and state and federal agencies.

PJM is estimating approximately 11,000 MW of coal-fired capacity at high risk for retirement, and another 14,000 MW at risk for retirement due to MATS and CSAPR.

6.1.2.3 MATS Impact in New York

In New York, 32 generators with an aggregate capacity of 10.8 GW will be subject to the new MATS rule. The majority of the coal fired capacity in New York currently has installed emission control technologies that when operated at near maximum efficiencies will be able to achieve compliance with the limitations. The balance of the coal fired capacity will need to make choices about retrofitting, retiring or fuel changes. NYSDEC's Part 246 limits the emissions of mercury from coal fired power plants to levels that are approximately ½ of those required by MATS in 2015.

Approximately 8 GW of heavy oil fired capacity is subject to this rule and will need to make choices about limiting the use of heavy oil in the future or retrofitting particulate control technologies. The MATS rule provides for a subcategory for limit use oil fired EGUs. If units in this subcategory restrict the use of heavy oil within the prescribed limits, then the rule does not impose numerical emission limits, rather periodic combustion optimization actions are required.

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[70] National Association of Regulatory Utility Commissioners, *NARUC Launches New Task Force on Environmental Policies, Press Release* (February 7, 2012) http://www.naruc.org/News/default.cfm?pr=302

[71] FERC Staff White Paper on the Commission's Role Regarding EPA's Mercury and Air Toxics Standards (January 30, 2012). See: http://www.ferc.gov/media/news-releases/2012/2012-1/01-30-12-white-paper.pdf

[72] Comments of the ISO/RTO Council on FERC's Role Regarding EPA's Mercury and Air Toxics Standards, FERC Docket No. AD12-1-000 (February 29, 2012). See: http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRCCommentsinAD12-1.pdf

6.1.2.4 MATS Impact in New England

In New England, MATS affects 7.9 GW of existing installed capacity, either coal steam or oil/gas steam units. Of that affected capacity, many coal steam generators already have installed or planned the retrofit of needed air pollution control devices. For example, 1.9 GW of affected capacity report retrofit of activated carbon injection for mercury control, 1.3 GW of affected capacity report some installed flue gas desulfurization control devices for SO2 control, and 1 GW report installed fabric filter baghouses for particulate control. Many of these retrofit air pollution control devices were required by state environmental regulations. Existing liquid oil-fired generators lack the needed pollution control devices for compliance with proposed MATS and are expected to rely on the MATS limited capacity factor exemption to avoid any retrofits and instead rely on complying with combustion optimization requirements.

Affected generators in New England with already installed or planned (meaning controls are expected to commence operation prior to 2015) are deemed not to be at-risk generators. Based on review of publicly reported information concerning existing or planned pollution control devices at existing affected generators, along with the likely needed additional pollution control devices, estimated capital costs and average construction schedules for such retrofit projects, ISO-NE estimates that less than 1 GW of environmental retirements are expected by the January 2015 compliance deadline under MATS.

6.1.3 Cross-State Air Pollution Rule

EPA finalized the *Cross-State Air Pollution Rule* (CSAPR) in 2011. The purpose of the rule is to reduce SO_2 and NO_X emissions from fossil fuel fired generators that contribute to the formation of ground-level ozone and fine particulates across 31 states and the District of Columbia and their downwind transport. CSAPR uses cap-and-trade programs limiting sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions from fossil-fired generators over 25 MW beginning in 2012.

CSAPR replaces the *Clean Air Interstate Rule* (CAIR). Both CSAPR and CAIR are designed to reduce SO_2 and NO_X emissions from fossil fuel-fired generators by utilizing cap and trade emission reduction programs to comply with *CAA § 110(a)(2)(D)*, which prohibits sources of air pollution in upwind states from “contributing significantly” to poor air quality in downwind states.[73]

On December 30, 2011 the U.S. Court of Appeals for the District of Columbia issued an order, delaying implementation of CSAPR, with arguments scheduled for April 2012 and a decision expected later in 2012.[74] During the interim, the U.S. Court of Appeals for the District of Columbia directed EPA to continue implementing CAIR, which CSAPR was to have replaced beginning January 1, 2012. It is expected that generators will be subject to CAIR programs through calendar year 2012.

[73] U.S. EPA, *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals; Final Rule*, 76 Fed. Reg. 48208 (August 8, 2011); *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call; Final Rule*, 70 Fed. Reg. 25162 (May 12, 2005).

[74] EME Homer City Generation, L.P. v. U.S. EPA, No. 11-1302 D.C. Circuit (December 30, 2011) Order staying CSAPR pending the court’s resolution of the petitions for review.

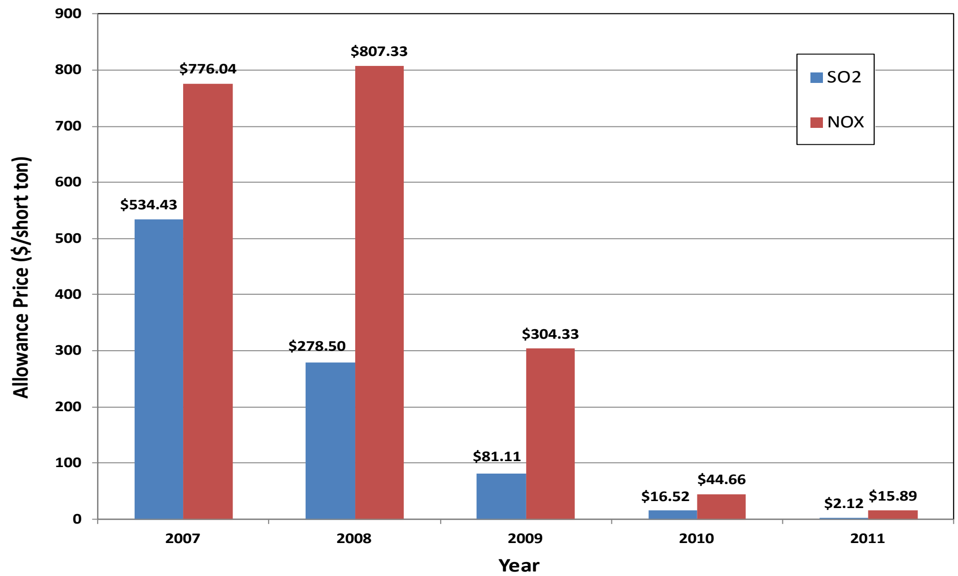

Figure 6-3. CAIR SO_2 and NO_X Allowance Price Trends (Dollars per Short Ton)[75]

As Figure 6-3 illustrates, CAIR allowance prices have declined dramatically, lowering generator compliance costs since the CAIR program was remanded to EPA for replacement by CSAPR. CAIR allowance prices are expected to remain near historic lows through the temporary extension of the CAIR program through 2012.

Table 6-5 Total CSAPR State Allowance Allocations (Million Tons/Year)

	2012 Base Case	2012 CSAPR	2012 Emission Reductions	2014 Base Case	2014 CSAPR	2014 Emission Reductions
Annual SO_2	7.0	3.0	-4.0	6.2	2.4	-3.9
Annual NO_X	1.4	1.3	-0.1	1.4	1.2	-0.2
Ozone Season NO_X	0.7	0.6	-0.1	0.7	0.6	-0.1

[75] EIA, *Emissions Allowance Prices for SO_2 and NO_x Remained low in 2011* (February 2, 2011)., "The prices of annual SO_2 and summer seasonal nitrogen oxides NO_x emissions allowances from the CAIR and the NO_x Budget Trading Program (NBP) have fallen. Average SO_2 prices in 2007 were $534/ton, and fell to an average of $2.12/ton in 2011. NO_x prices showed a similar dramatic drop from $807/ton in 2008 to $15.89/ton by 2011. The drop in the value of allowances began after the D.C. Court of Appeals struck down CAIR, in July 2008, and continued through the end of 2011." See http://www.eia.gov/todayinenergy/detail.cfm?id=4830

CSAPR is designed to replace CAIR. By 2014, EPA estimates this rule, along with concurrent state and other EPA actions would reduce power plant SO_2 emissions by 71 percent and NO_x emissions by 52 percent over 2005 levels.

EPA finalized technical amendments to CSAPR, addressing discrepancies in unit specific modeling assumptions that affected the proper calculation of CSAPR final state budgets and assurance levels in Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York, Texas and Wisconsin, along with new unit set asides in Arkansas and Texas.[76] For affected States in the Northeast the proposed adjustments in allowance allocations include:

- Revisions to New Jersey's ozone season NO_x, annual NO_x and SO_2 budgets to account for an erroneously assumed FGD and SCR emission control devices at one unit, and taking into account operational constraints likely to necessitate non-economic generation at six facilities (Bergen, Edison, Essex, Kearny, Linden, and Sewaren);
- Revisions to New York's ozone season NO_x, annual NO_x and SO_2 budgets to account operational constraints likely to necessitate non-economic generation at ten units;

With no carryover of existing CAIR or Acid Rain Program compliance allowances; compliance will likely require additional retrofits or upgrades of various control technology options: sulfur dioxide (SO_2) controls including limestone-based flue gas desulfurization (FGD) or dry sorbent injection (DSI); nitrogen oxides (NO_x) controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR); existing control devices may require optimization to achieve higher removal efficiencies, more reagents, increasing costs.

On February 21, 2012 technical corrections to CSAPR were published in the Federal Register, which may become effective if the stay is lifted. Also published on February 21, 2012 were increases to CSAPR state budget allocations for several states including New Jersey and New York, correcting errors in the modeling used to calculate allowance allocations.

6.1.3.1 Cross-State Air Pollution Rule Impact in PJM

PJM has assessed existing coal capacity at risk for retirement as a result of both CSAPR and MATS, and determined that based on comparing the net capacity revenues required to cover environmental retrofit costs to the net cost of new entry (CONE) PJM. 11 GW are at most risk (require net capacity revenues that are greater than 1.5 times the net CONE, and 14 GW are at some risk (require net capacity revenues that are between 1.0 and 1.5 times the net CONE. Figure 6-4, Figure 6-5, and Figure 6-6 illustrate a comparison between 2010 state emissions levels and CSAPR allowance budgets for SO_2, NO_X, and ozone season NO_X, respectively, in the PJM service area.

New Jersey has already instituted a high electric demand day (HEDD) rule that sets strict NO_x emissions limits for existing sources in 2015. This rule may result in the retirement of a large number of peaking units in New Jersey, which not only provide energy on days when it is most needed, but may also provide regulation and voltage support and/or black start services.

[76] U.S. EPA, *Revisions to Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Final Rule*, 77 Fed.Reg. 10324 (February 21, 2012), and, *Revisions to Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone, Direct Final Rule*, 77 Fed.Reg. 10342 (February 21, 2012).

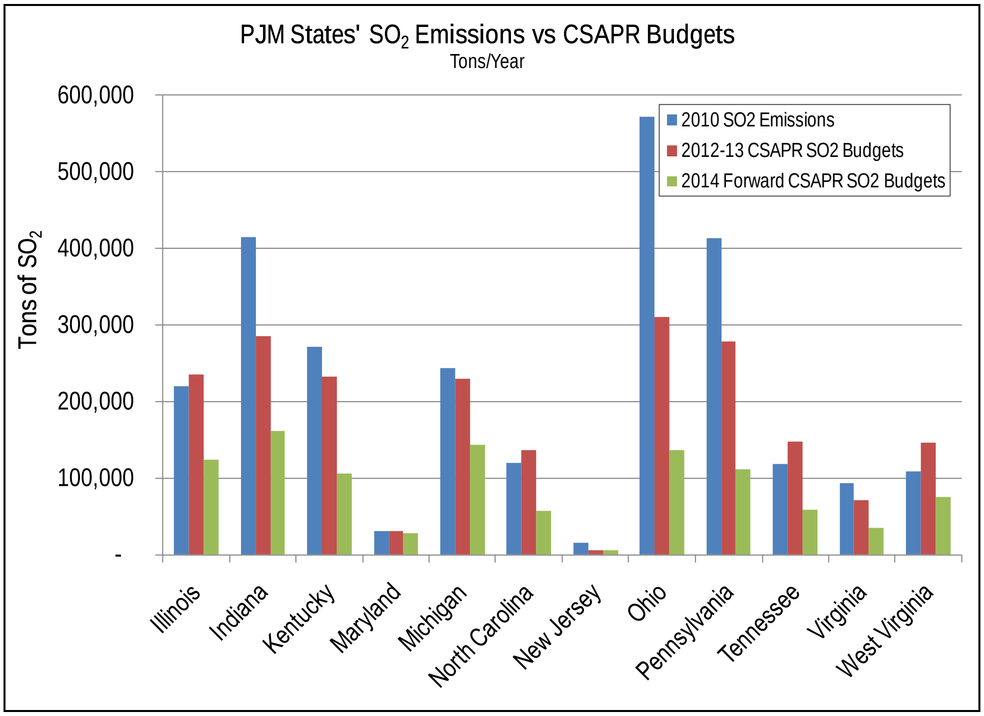

Figure 6-4: 2010 State SO_2 Emissions Compared to CSAPR Budgets in PJM Area

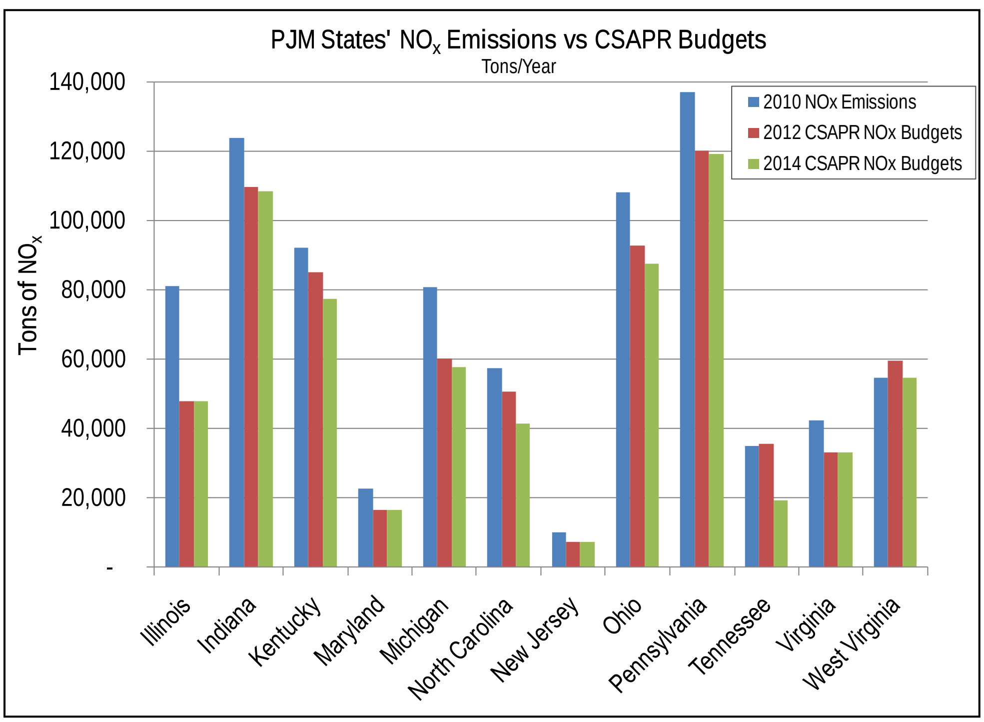

Figure 6-5: 2010 State NO_X Emissions Compared to CSAPR Budgets in PJM

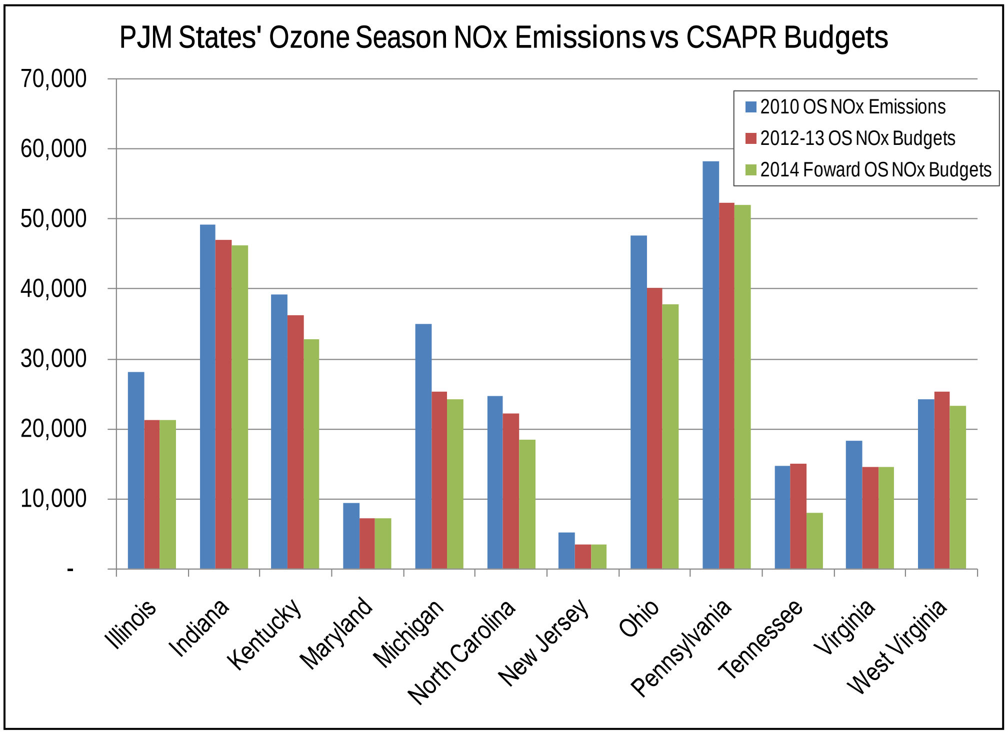

Figure 6-6: 2010 State Ozone Season NO_X Emissions Compared to CSAPR Budgets in PJM

6.1.3.2 Cross-State Air Pollution Rule Impact in New York

In New York, 167 units representing 23,275 MW of capacity are subject to the CSAPR rule as promulgated. A review of the emission history of the affected units shows that there are several possible scenarios that can lead to compliance with the State Emission Allowance Budgets. The possible courses of action include, optimum operation of existing emission control equipment, fuel switching, redispatching, out of state allowance purchases, and limited retirements.

6.1.3.3 Cross-State Air Pollution Rule Impact in New England

In New England, an estimated 15.9 GW of installed fossil fuel capacity would have been subject to the proposed CATR. As the table above shows, CSAPR excluded generators in Connecticut and Massachusetts, and elimination of the seasonal NO_x control program in Massachusetts.

In the CATR preamble EPA notes that in the Northeast a large number of EGUs serving generators with a nameplate capacity equal to or less than 25 MW contribute NO_x emissions to ozone problems on high electric demand days (HEDD), usually on the hottest days in the summer where meteorological conditions help convert the increased NO_x emissions to ozone.[77] There is regional interest from the Ozone Transport Commission and affected state air regulators in lowering the 25 MW applicability threshold in

[77] U.S. EPA, *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone; Proposed Rule*, 75 Fed.Reg. 45210, 45309 (August 2, 2010).

the ozone season program to deal with this issue and/or potentially requiring these units to operate with greater controls than a trading program may necessitate.

6.2 Greenhouse Gas Reduction Programs

This section summarizes recent federal action on greenhouse gases emitted by generators and discusses the Regional Greenhouse Gas Initiative (RGGI) and other regional and state initiatives to reduce greenhouse gases.

6.2.1 Proposed Greenhouse Gas New Source Performance Standards

On April 13, 2012, EPA published in the Federal Register proposed New Source Performance Standards (NSPS) for greenhouse gases emitted by new natural gas, oil and coal-fired electric generators.[78] New fossil fuel-fired generators over 25 MW would be required to comply with an output based emission limit of 1,000 lbs CO_2/MWh.[79]

EPA asserts 95 percent of the natural gas-fired advanced combined cycle generators commencing operation since 2005 would meet the proposed NSPS without additional control technologies and new pulverized coal- or petroleum coke-fired generators equipped with carbon capture sequestration technology capable of removing 50 percent of CO_2 emissions will be capable of meeting the standard, however it is important to note that such technology does not exist and is not believed to be economic. Natural gas-fired simple cycle combusting turbines intended for use as peaking units are excluded from the proposed GHG NSPS.[80]

Preliminary analyses of the proposed GHG NSPS suggests if natural gas-fired simple cycle combustion turbines were not excluded from its jurisdiction, the proposed GHG NSPS would preclude addition of currently available new simple cycle natural gas-fired combustion turbines and require operational constraints (load following) on some currently available new natural gas-fired combined cycle generators.[81]

6.2.2 Carbon Dioxide (CO_2) Regulation and Cap and Trade Programs

This section summarizes RGGI and discusses other regional and state initiatives to reduce greenhouse gases.

6.2.2.1 RGGI

On January 1, 2009 RGGI took effect in the original ten participating Northeastern states. RGGI applies to carbon dioxide emissions from fossil power plants 25 MW and larger in those states. The RGGI states include those served by ISO New England, NYISO and three states in PJM (Delaware, Maryland, and New Jersey). New Jersey announced that it would withdraw from RGGI at the close of the initial compliance period, which ends on December 31, 2011.[82] The annual 10 state cap was 188 million (short)

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[78] More information concerning the GHG NSPS is available at: http://www.epa.gov/airquality/cps/index.html

[79] EPA, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources; Electric Utility Generating Units; Proposed Rule*, 77 Fed.Reg. 22392 (April 13, 2012). The proposed GHG NSPS does not address existing generators whose CO2 emissions increase as a result of installation of pollution controls for conventional pollutants, or for proposed generators that have acquired a complete preconstruction permit by the time the proposed GHG NSPS and start construction prior to April 2013.

[80] Id. at 22411.

[81] Matthew J. Kotchen and Erin T. Mansur, "How Stringent is the EPA's Proposed Carbon Pollution Standard for New Power Plants?" (April 2012), see http://www.uce3.berkeley.edu/WP_039.pdf

[82] Letter of Bob Martin, Commissioner New Jersey Department of Environmental Protection to Jonathan Schrag, Executive Director, Regional Greenhouse Gas Initiative (May 31, 2011), http://www.rggi.org/docs/New_Jersey_Letter.pdf, Mireya

tons through 2014. Each state is allocated a share of the allowances, as shown in Figure 6-7 on the basis of historical emissions and negotiations.[83]

Under the existing RGGI MOU, between 2015 and 2018, the cap will decrease 2.5% per year, or a total of 10% by 2018.

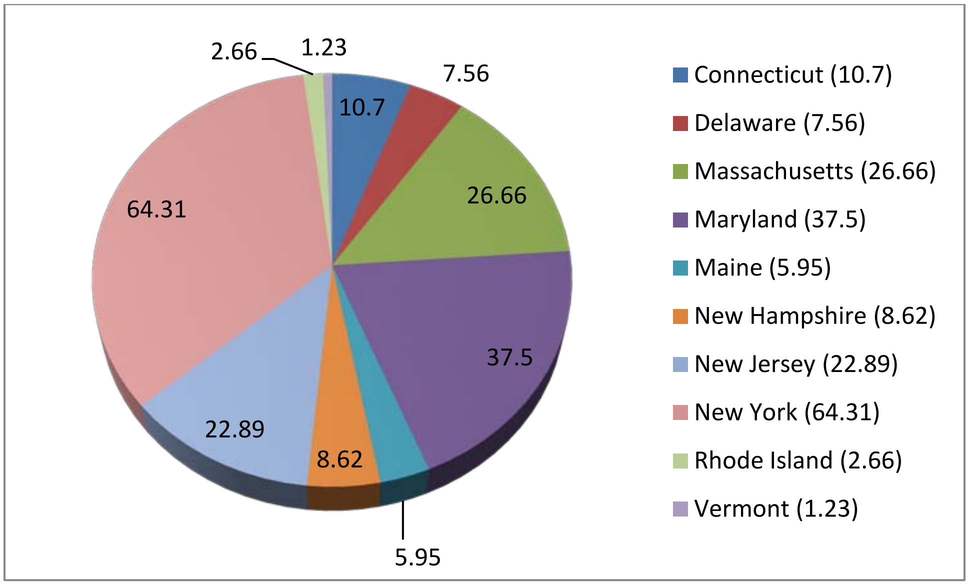

Figure 6-7: State Annual RGGI Allowances for 2009 to 2014 (Million Short Tons)

The second RGGI compliance period began on January 1, 2012 and runs through 2014. Changes include the withdrawal of New Jersey, a reduction in total allowances to 141 million tons offered in quarterly auctions during 2012. Connecticut, Delaware, Massachusetts, New York, Rhode Island, and Vermont announced their intentions to retire unsold allowances from the first compliance period.[84] Several states are moving forward with unsold RGGI allowance retirements or modifying existing State RGGI regulations to enable retirement of unsold RGGI allowances.

The generators affected by RGGI are responsible for acquiring the allowances they need to cover their actual CO_2 emissions over the three-year period. Generators were the major purchasers of the quarterly RGGI auction allowances. They may also use the secondary market to supplement the allowances obtained from the RGGI auctions. Secondary market prices have tracked the decline to the auction floor price, averaging below $2/ton with limited trading activity.[85] Beside the generators purchasing allowances in the RGGI auctions, they may use early-reduction allowances (i.e., reductions made in 2006 through 2008 below the RGGI historical emissions baseline), or use a combination of both measures. The reduction of CO_2 emissions is achieved through a combination of the reduction of the use of electricity, improving the heat rates (Btu/kWh) of the generating units, and/or switching from higher-emitting units that are typically low in cost to lower-emitting units that are typically higher in cost. The CO_2 prices seen

Navarro, Christie Pulls New Jersey from 10-State Climate Initiative, *The New York Times*, May 26, 2011, http://www.nytimes.com/2011/05/27/nyregion/christie-pulls-nj-from-greenhouse-gas-coalition.html?_r=2&ref=nyregion

[83] Under RGGI, one allowance equals the limited right to emit one ton of CO_2.

[84] See: http://rggi.org/docs/Auctions/011712_Announcement-2012-Auctions.pdf (January 17, 2012).

[85] "Market Comment," Carbon Market North America, *Point Carbon News*: Vol. 6 Issue 21 (June 3, 2011); http://www.pointcarbon.com/polopoly_fs/1.1545984!CMNA20110603.pdf.

in RGGI do not provide any incentive to switch from coal or oil and gas steam to natural gas units, and as shown in the PJM whitepaper, it would take a CO_2 price in excess of $30/ton to induce a great deal of switching from coal to combined cycle natural gas.[86] Consequently, the reliability impacts of RGGI are currently minimal.[87]

Under RGGI's Memorandum of Understanding, a program review is required by 2012 to evaluate various issues in the design, market performance, and achieved reductions and to improve its performance. The evaluation will assess the reserve floor price mechanism for future allowance auctions.[88]

6.2.2.2 Other State and Regional GHG Initiatives

In New England, Connecticut has set a target of 10 percent below 1990 levels by 2020; 80 percent below 2001 levels by 2050. Maine - 1990 levels by 2010; 10 percent below 1990 levels by 2020; 75-80 percent below 2003 levels beyond 2020. Massachusetts (RGGI) - 80 percent below 1990 levels by 2050. New Hampshire - 1990 levels by 2010; 10 percent below 1990 levels by 2020; and 75-85 percent below 2001 levels in the long term. Rhode Island (RGGI) - 1990 levels by 2010; 10 percent below 1990 levels by 2020; and 75-85 percent below 2001 levels beyond 2020. Vermont (RGGI) - 1990 levels by 2010; 10 percent below 1990 levels by 2020; 75-85 percent below 2001 levels beyond.

New York State has a GHG reduction target of 5 percent below 1990 levels by 2010; 10 percent below 1990 levels by 2020.[89] These policies taken together and when considered with environmental regulations at the federal level may influence the makeup of the generation fleet going forward, putting an emphasis on generating technologies with less environmental impact.

In PJM there are a number of states that have set GHG reduction targets. New Jersey has set a target of reducing greenhouse gas emissions to 1990 levels, a reduction of 20 percent by 2020 and by 80 percent by 2050. Illinois set a target of 1990 levels by 2020 and 60 percent below 1990 levels by 2050. Maryland has a target of a 25 percent GHG reduction below 2006 levels by 2020 and 80 percent below 2006 levels by 2050. Pennsylvania's Climate Action Plan recommends a target of a 30 percent GHG reduction below 2000 levels by 2020. Virginia has a target of *30* percent GHG reduction below 2035 business-as-usual levels by 2025. Michigan set a goal to reduce the state's greenhouse gas (GHG) emissions to 20 percent below 2005 levels by 2025 and 80 percent below 2005 by 2050.

Other regional GHG initiatives include the final GHG cap and trade regulation adopted by the Province of Quebec in December 2011, taking effect in January 2013.[90] It will cap carbon dioxide emissions 20 percent below 1990 levels by 2020 to align itself with the goals of the Western Climate Initiative (WCI), principally consisting of California, a regional GHG control program including California and potentially other States and Provinces.[91] The Quebec GHG cap and trade program will seek annual reductions of 80

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[86] "Potential Effects of Proposed Climate Change Policies on PJM's Energy Market," available at http://www.pjm.com/documents/~/media/documents/reports/20090127-carbon-emissions-whitepaper.ashx.

[87] NYISO, *An Empirical Test for Inter-State Carbon-Dioxide Emissions Leakage Resulting from the Regional Greenhouse Gas Initiative* (April 20, 2011) available at: http://www.nyiso.com/public/webdocs/newsroom/other_reports/Report_on_Empirical_Test_for_Interstate_CO2_Emissions_Leakage_04202011_FINAL.pdf

[88] RGGI Program Review; http://www.rggi.org/design/program_review

[89] Center for Climate and Energy Solutions, U.S. State-Level Greenhouse Gas Reduction Targets, see: http://www.c2es.org/what_s_being_done/in_the_states/emissionstargets_map.cfm (Accessed March 7, 2012). Also, see EPA Statewide GHG Targets, available at: http://www.epa.gov/statelocalclimate/state/tracking/targets-caps.html

[90] Quebec Environmental Quality Act Section 46.5 (R.S.Q. c. Q-2), Final Regulation Respecting A Cap-and-Trade System for Greenhouse Gas Emission Allowances, See http://www.mddep.gouv.qc.ca/changements/carbone/Systeme-plafonnement-droits-GES-en.htm

[91] Carbon Market North America, Quebec to Launch CO2 Market Despite Industry Concerns December 2011

million metric tons CO_2 equivalent by capping emissions on the 100 largest emitters in the province beginning in 2013 and adding smaller sources in later years.[92] Due to preponderance of hydro-electric generation in the province, the provincial GHG compliance obligations are expected to impact industry, particularly oil refining, most heavily.

6.2.2.3 EPA Guidance on SO_2 National Ambient Air Quality Standards Compliance Planning

On September 22, 2011, the USEPA issued guidance on preparing State Implementation Plans (SIPs) to comply with the primary SO_2 NAAQS revised in June 2010.[93] The draft SO_2 NAAQS SIP submission guidance generated a substantial response from States and industry.[94] Commentators expressed concerns with the implementation timeline, thresholds used in the dispersion modeling analysis, and the reliance on modeling for demonstrating attainment. Many state and industry commentators believe the proposed timeline for the required dispersion modeling analyses, SIP development and submission requiring States to have needed remedies in place by June 3, 2013 for attainment/unclassifiable areas, and February 2014 for nonattainment areas, is unrealistic.

Potential control measures could include source specific emissions limits of SO_2, which could limit source compliance options under CSAPR. Additionally, concerns over the thresholds used to determine when air quality analyses should be conducted were expressed, with the use of actual emissions over 100 tons per year as a threshold rather than potential emissions being suggested. Also, concerns were expressed about the reliance on dispersion modeling to demonstrate attainment, at the expense of ambient monitoring data, which could provide more accurate information. If unaddressed, these issues could result in generators being subject to unnecessarily stringent permit restrictions on SO_2 emissions, at a time when CSAPR and MATS are being implemented.

7 Renewable Portfolio Standards

Most all states served by the three ISO/RTOs have renewable portfolio standards or related energy policies. In some cases the states also include energy efficiency goals. Table 7-1 summarizes the goals of these renewable portfolio standards and related policies, including any special features for the 20 states plus the District of Columbia served by of the three ISO/RTOs. Four of the states have no RPS, but one of them has a state goal for renewable energy supply.

[92] Quebec Publishes Draft Regulation On Cap-And-Trade System August 2011. The regulation applies to the largest GHG emitters, principally in the areas of mining and quarrying; oil and natural gas extraction; electric power generation, transmission and distribution; natural gas distribution; steam and air-conditioning supply; manufacturing; and pipeline transportation of natural gas. Emitters subject to the regulation with annual GHG emissions at or over the threshold of 25,000 metric tonnes CO2 equivalent will have a general obligation to "cover" their emissions in order to meet their emissions cap or reduction target. Thus, starting in 2013, the operators of about 100 establishments, mainly in the industrial and electricity sectors, whose annual GHG emissions are 25,000 metric tonnes CO_2 eq. will be subject to a cap and will have to reduce their GHG emissions.

[93] USEPA. Guidance for 1-Hour SO2 NAAQS SIP Submissions. September 22, 2011. See at: http://www.epa.gov/airquality/sulfurdioxide/pdfs/DraftSO2Guidance_9-22-11.pdf

[94] The comments may be found at: http://www.regulations.gov, EPA's electronic public docket and comment system. (Docket ID No. EPA-HQ-OAR-2010-1059)

Table 7-1: State Renewable Portfolio Standards/Policy Requirements for new Renewable Resources in the ISO/RTOs Service Areas[95]

State	New or Total Renewable Classes - %	Target Year	Comments
ISO-NE			
Maine	10	2017	New renewables, 30% existing
New Hampshire	11	2020	0.3% solar (by energy) target by 2014, existing hydro and biomass
Vermont	25*	2025	Not a RPS but a state goal for energy from forest and farm renewable sources
Massachusetts	15	2020	Existing Clas for hydro and waste-to-energy
Rhode Island	14	2019	Additional 2% for existing or new Class II
Connecticut	20	2020	Class II for existing, Class III for CHP and energy efficiency
NYISO			
New York	30	2015	Includes existing large hydro
PJM			
New Jersey	22.5	2020-2021	5,316 GWh must be from solar
Pennsylvania	18	2021	Includes new and existing in 2 tiers defined by technologies; 0.5% must be from solar
Delaware	25	2025-2026	3.5% must be from solar
Maryland	20	2022	2% must be from solar
District of Columbia	20	2020	0.4% minimum for solar
Virginia	15*	2025	Voluntary; percent based on recent year sales
West Virginia	25	2025	
Kentucky			Has no RPS
North Carolina	12.5	2021	0.2% must be from solar by 2018
Tennessee			Has no RPS
Ohio	25	2024	Alternative technology standard with 12.5% from renewables; solar minimum of 0.5%
Indiana	10*	2025	Voluntary; percent based on 2010 sales
Illinois	25	2025-2026	18.75% from wind, 1.5% from solar by 2026
Michigan	10	2015	Additional MW targets for larger utilities

* denotes a voluntary state goal rather than a RPS

These renewable portfolio standards and related policies specify different types of renewable energy technologies. These typically encompass solar, wind, landfill gas, biomass and other special types of energy technologies that vary among the states. Most of the states also have one or more classes for existing renewable resources that typically cover small hydro, biomass energy and refuse plants. The load serving entities that must comply with the standard do so by buying Renewable Energy Credits (RECs) from projects within the states or nearby ones. The states may also have an alternative compliance payment feature the may be used in place of meeting the RPS by buying RECs. This serves as a price cap on the price of RECs.

A detailed summary of RPS goals for all states within each of the three ISO/RTO regions was included in a June 2011 report,[96] and was presented at the June 2011 IPSAC meeting.[97]

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[95] Source: North Carolina State University, Databases of State Incentives for Renewables and Efficiency (DSIRE)(DOE, NREL contract); http://www.dsireusa.org/

[96] Refer to Section 3 of the report titled 2011 Joint Report on the Impact of Environmental and Renewable Technology Issues in the Northeast, June 24, 2011. See: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/reports/2011/env_renewable_report.pdf

7.1 Interconnection Queues

Renewable resource development is being driven in part by renewable portfolio standards (RPS) that most states throughout the ISO/RTO regions have established. Table 7-2 lists the renewable projects in the ISO-NE, NYISO, and PJM generator interconnection queues as of February 1, 2012. A total of 682 projects with an aggregate nameplate capacity of 48,324 MW are listed in the three ISO/RTO queues. With respect to queue renewable projects reported for NCSP09 (a total of 59,386 MW, as of October/November 2009 queue dates), capacity in the queues as of February 1, 2012 represent an 18.6% reduction in renewable resource capacity seeking interconnection. Wind projects comprise almost 89% of the renewable queue projects. Since NCSP09, there has been a significant increase in the number of solar projects seeking interconnection, which now represent 7% of all the renewable capacity in the queues, the majority of which is in the PJM service area.

Table 7-2: Renewable Resource Projects in the ISO-NE, NYISO, and PJM Queues – MW (# of Projects)

ISO/RTO	Onshore Wind	Offshore Wind	Biomass	Convent. Hydro	Landfill Gas	Fuel Cells	Solar	Total
ISO-NE	1,921 (31)	474 (2)	313 (9)	35 (7)	28 (1)	9 (1)	21 (4)	2,801 (55)
NYISO	3,431 (38)	1,261 (3)	30 (2)	14 (3)	26 (5)	0 (0)	0 (0)	4,762 (51)
PJM	34,002 (185)	1,789 (7)	932 (17)	311 (11)	160 (29)	207 (7)	3,360 (320)	40,761 (576)
Total	**39,354 (254)**	**3,524 (12)**	**1,275 (28)**	**360 (21)**	**214 (35)**	**216 (8)**	**3,381 (324)**	**48,324 (682)**

These projects, if developed, would be sufficient to meet the RPS short term goals while recognizing that contributions could come from other RPS sources not in the queues.

8 Wind and Renewable Resource Studies

The two most common renewable resources are wind and solar technologies. As presented in Section 7.1, these two resources comprise more than 95% of renewable resource projects in the ISO/RTO interconnection queues, totaling more than 46 GW of nameplate capacity. Both wind and solar technologies are weather-driven, variable generation resources that pose operational challenges to each ISO/RTO. The JIPC is one of several venues through which ISO-NE, NYISO, and PJM share information concerning their respective planning efforts to expedite the efficient and reliable integration of these resources into the overall system.

A detailed summary of all wind and renewable resource studies within each of the three ISO/RTO regions was included in a June 2011 report,[98] and was also presented to the IPSAC in June.[99]

[97] Refer to the June 27, 2011 IPSAC presentation: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/jun272011/env_renewable_report.pdf

[98] Refer to Section 4 of the report titled 2011 Joint Report on the Impact of Environmental and Renewable Technology Issues in the Northeast, June 24, 2011.

[99] Refer to the following June 27, 2011 IPSAC presentation: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/jun272011/ipsac_environmental.pdf

9 Demand Side Resource Development

Demand side resources (DSR) may have peaking, intermediate, and baseload characteristics and utilize a variety of technologies that either modify the load or utilize distributed generation resources. Demand side resources may modify their electric energy consumption in response to incentives based on wholesale markets. Examples include high performance new buildings, thermal envelope improvements, high efficiency HVAC systems, and advanced lighting. Distributed generation may include a variety of units, such as combined heat and power, solar arrays, and small wind farms. The best locations for demand side resources are usually in areas where they can help serve load, reduce transmission congestion, and improve system reliability. Emergency diesel generators have emissions-based permitting restrictions, but can serve a reliability function.

Underlying these initiatives is the FERC policy mandate that DSRs be allowed to participate in markets in a manner that is comparable to generation resources. While demand resources may reduce the need to build physical infrastructure, successfully integrating demand-response resources into the electric power system presents many challenges. These include operational, planning, and market issues presented by this large penetration of demand-response resources.

9.1 PJM

PJM has a comprehensive program to ensure comparable treatment of demand side resources and alternatives. PJM incorporates quantities of Load Management (LM), Energy Efficiency (EE), Price Responsive Demand (PRD) and Behind-the-Meter (BtM) generation to supplement PJM's independently developed base, unrestricted load forecast. Through these FERC approved mechanisms, energy consuming entities have greatly enhanced access to options to reliably meet their electrical energy and capacity responsibilities.

The Load Management component was formerly composed of Interruptible Load for Reliability (ILR) and Demand Resource (DR) components. However, ILR was discontinued as of the 2012/2013 delivery year. ILR components had the option to either participate in PJM's three year forward Reliability Pricing Model (RPM) auction or to delay notice of their commitment until three months prior to the start of the delivery year. ILR components participating at this later date were causing disruptions to the capacity market prices. Effective June 1, 2012, the ILR program will be discontinued so that all Load Management programs will be required to commit on the same three-year ahead schedule as generation resources. The DR potion of LM, forecasted for each zone, equals the amount of DR cleared in the RPM auctions. RPM procures the capacity required in PJM for system reliability. Products eligible to participate in RPM include generation, transmission upgrades, LM and EE. The amount of DR cleared in the last auction year is held constant for the remainder of the forecast.

The forecasted impact of approved EE programs equals the amount cleared in RPM auctions, and represents accelerated efficiency increases that would not otherwise occur, or would occur at a later time, without the EE program.

BtM generation is eligible, in any planning period, to elect to be treated as a BtM and net against load or as an LM resource according to the rules to PJM's applicable tariffs and agreements. PJM Manual 14D, Appendix A contains additional information about treatment of BtM generation.

PJM's current load forecast includes over 9,500 MW of LM and EE in its long term forecast. PJM recently tested LM for its capability to provide its committed level of load reduction for the 2010/2011 delivery year. These test results, in aggregate, demonstrated a response of 111% of capacity commitments or 624 MW in excess of the 5,734 MW of committed demand side resources.

PJM has performed sensitivity analyses on the integration of RPS, DR, and EE as required by individual state mandates. The sensitivity analysis focused on the reliability impacts on PJM's EH system throughout the 15 year planning horizon. The assumptions, procedure, and results of the study were presented and reviewed with the PJM Transmission Expansion Advisory Committee (TEAC) stakeholders.[100]

9.2 NYISO

9.2.1 Demand Response

The NYISO has two demand response programs that support reliability of the bulk power grid. The first is the Special Case Resource (SCR) program, which is part of the Installed Capacity (ICAP) market, and the second is the Emergency Demand Response Program (EDRP). In addition, the NYISO administers the Targeted Demand Response Program (TDRP) for the Transmission Owner for Zone J. SCR and EDRP resources are deployed for forecast or actual operating reserve shortages or other emergency reliability needs.

SCRs are end-use Loads capable of being reduced upon demand and distributed generators that are not visible to the NYISO's Market Information System. They enroll into the ICAP market through Responsible Interface Parties (RIPs). In order to participate in the ICAP market, resources must be rated at 100kW or higher, which can be achieved by aggregating SCRs, as long as they are in the same zone. RIPs are responsible for all forms of communication to and from the NYISO, including enrollment, offering into auctions, certification, notification of events, and dispatch of SCRs. They are also responsible for determining the amount of load reduction provided by the SCRs, submitting load reduction data to the NYISO, and distributing program payments from the NYISO to the SCRs.

SCRs participate in ICAP Auctions in the same manner as other ICAP suppliers. The amount of capacity a SCR is qualified to sell in the ICAP Auction is based on the SCR's pledged load reduction and its performance factor. The performance factor reflects the historical performance of the SCR and is determined from actual performance data. Once during each Capability Period, SCRs are required to perform a test of their pledged reduction. Each SCR's performance factor is based on the load reduction achieved during tests as well as any events during the Capability Period.

When possible, RIPs are given at least 21-hour advance notice that SCRs may be required the following day and a second notice two hours in advance of an event. When called upon for events of four hours or longer, RIPs will be paid for verified load reduction at the rate of each SCR's Minimum Payment Nomination (up to $500/MWh) or Real-Time zonal LBMP, whichever is greater, for the time frame in which the SCRs participated. For events that are less than four hours, RIPs will be paid for verified load reduction at the rate of the greater of the Minimum Payment Nomination or Real-Time zonal LBMP for at least the first two hours and then LBMP for the remainder of the event. If advance notices are given in accordance with the time periods identified above, participation during an event is mandatory for a minimum of the event duration or four hours, whichever is less. Performance penalties apply for nonperformance.

The EDRP allows participants to be paid for reducing their energy consumption upon notice from the NYISO that an operating reserves deficiency or major emergency exists. The program is open to interruptible loads or local "behind the fence" generation greater than or equal to 100 kWs per Zone.

[100] A link to the April 15, 2011 TEAC presentation discussing the analysis can be found at: http://www.pjm.com/~/media/committees-groups/committees/teac/20110415/20110415-reliability-analysis-update.ashx

If, as a result of the next day's load forecast, it is determined that an operating reserve shortage is likely after all available offers have been used, Dispatch Operations staff may choose to provide notice to participants that the SCR Program and the EDRP may be activated the next day. At the step where SCRs and EDRP resources are called upon in the Emergency Operation Manual and System Operation Procedures, the Dispatch Operations Shift Supervisor will use the web based SCR/EDRP notification system to contact program participants.

In response to a request for assistance from the Transmission Owner for Zone J, the NYISO can activate the Targeted Demand Response Program (TDRP) in one or more of eight sub load pockets within Load Zone J. Notifications will be made through the NYISO's Demand Response notification system; events will clearly be identified as Targeted Demand Response advisories or activations. Participation in a TDRP event is voluntary.

In July 2011, 1,859 MW of ICAP/SCR resources were called upon for demand response events and 148 MW of EDRP resources were available.

9.2.2 Energy Efficiency

In its June 2008 order enacting the Energy Efficiency Portfolio Standard, the New York State Public Service Commission (NY PSC) set a goal of reducing energy consumption by 15% of 2007's forecasted levels in 2015 (about 26,880 GWh) and approved spending through 2011. In 2009, the NYISO's long term energy forecast included about 40% of the statewide goal. At that level, the energy efficiency savings would equate to a 1,485 MW decrease in the peak load forecast by 2015. In its 2010 forecast, the energy efficiency reductions were increased to 1,675 MW, based on an expectation that funding would continue beyond 2011. As was the case in its 2009 reliability study, the 2010 reliability needs assessment determined that no new resources would be needed on the New York bulk power system through 2020. In October 2011, the NY PSC authorized additional spending through 2015 and left the overall program goals essentially unchanged. The NYISO continues to monitor the implementation of the energy efficiency programs to determine that they are achieving impacts in energy and peak demand reductions as expected.

9.3 ISO New England

9.3.1 Demand Resources in ISO-NE's Forward Capacity Market

Demand resources of all types may provide reserve, capacity, or they may support more economically efficient uses of electrical energy. Referring to demand resources as an important component of well-functioning wholesale markets, ISO-NE has allowed DSRs to participate in its first five Forward Capacity Auctions (FCAs).

The analysis for calculating the Installed Capacity Requirement (ICR) for New England examines system resource adequacy under assumptions for the load forecast, resource availability, and possible tie-line benefits. The model also accounts for the load and capacity relief that can be obtained from implementing operating procedures, including load response programs.

The amounts of capacity that will be procured through the Forward Capacity Market (FCM) process for future years will continue to be determined according to established FCM market rules. The FCM demand resources that will deliver in a particular FCM's capacity commitment period belong to one of two general categories: passive and active.

- Passive projects (e.g., energy efficiency), which are designed to save electric energy (MWh). The electric energy that passive projects save during peak hours helps fulfill ICRs. These projects do not reduce load based on real-time system conditions or ISO instructions. The FCM includes two types of passive projects:
    - On peak—passive, non-weather-sensitive loads, such as efficient lighting
    - Seasonal peak—passive, weather-sensitive loads, such as efficient heating and air conditioning (HVAC)
- Active projects (e.g., demand response), which are designed to reduce peaks in electric energy use and supply capacity by reducing peak load (MW). These resources can reduce load based on real-time system conditions or ISO instructions. The FCM includes two types of active projects:
    - Real-time demand response—active, individual resources, such as active load management and distributed generation at commercial and industrial facilities
    - Real-time emergency generation—active, emergency distributed generation

Table 9-1 shows the breakdown of demand resources that have cleared in the first five Forward Capacity Auctions. Demand side resources acquired through the FCM thus far have become existing capacity available for meeting future capacity needs.

Table 9-1: Capacity Supply Obligation for New Capacity Procured during the Forward Capacity Auctions (MW)

Demand Resource	FCA#1 (MW)	FCA#2 (MW)	FCA#3 (MW)	FCA#4 (MW)	FCA#5 (MW)
Active Demand Resources	576	185	98	257	42
Passive Demand Resources	284	262	211	258	221
Demand Resource Total	**860**	**447**	**309**	**515**	**263**

9.3.2 Development of ISO-NE's Energy Efficiency Forecast

Many New England states are making large investments in energy efficiency via an assortment of state programs. To date, ISO-NE has incorporated energy efficiency into its load forecast in two ways: (1) energy efficiency projects that have already been completed, while not modeled as an FCM resource, are reflected in historical data and subsequent load forecasts, and (2) future federal appliance efficiency standards are reflected. In addition, energy efficiency resources with obligations in the FCM are treated as resources that contribute toward meeting New England's ICR, as explained in Section 9.3.1. Beyond the FCM timeframe, however, levels of energy efficiency are held constant, and are therefore not captured in ten-year-out transmission planning studies.

In order to better integrate energy efficiency in long-term ISO/RTO planning, ISO-NE conducted a survey of methodologies utilized by other ISO/RTOs within the IRC, and initiated a discussion of each ISO/RTO's methodologies with the IPSAC in March 2011.[101] Among other ISO/RTOs, NYISO's method of forecasting longer term energy efficiency based on forecasted "production costs" (MWh savings per

[101] Refer to the following presentations: (1) Integrating Energy Efficiency in Long-Term ISO/RTO Planning, found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/mar302011/energy_efficiency.pdf; (2) Energy Efficiency Forecasting in New York, found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/mar302011/nyiso_ee_forecasting.pdf; (3) Load Management and Energy in PJM, found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2011/mar302011/pjm_lm_and_ee.pdf.

dollar spent) and budgets of energy efficiency programs was found compatible with ISO-NE's needs, and further information sharing was conducted between the two ISO/RTOs.

As a result of the information shared within both the IRC and JIPC interregional forums, ISO-NE is now developing an energy efficiency forecast.[102] In February 2012, ISO-NE created the Energy Efficiency Forecast Working Group (EEFWG) to provide ongoing input to the forecast process,[103] and the initial energy efficiency forecast will be completed as part of the annual forecast cycle in spring 2012.[104]

9.4 Conclusions

Reliable and cost-effective DSRs are given full consideration along with other resources available to address grid reliability and economic congestion problems in the regional planning processes. Aggressive energy efficiency goals in a number of states within the ISO/RTOs area are introducing the need to consider how to address these goals in long-term planning. Continued work is being conducted to integrate the increasing amount of DSRs, and will continue to be supported by the coordination of these activities by the ISO/RTOs.

10 FERC Order 1000: Transmission Planning & Cost Allocation

10.1 Background

FERC's Order 1000, issued on July 21, 2011, is the Final Rule in Docket RM10-23-000 which was initiated with a Notice of Proposed Rulemaking (NOPR) issued in June 2010 as a follow-up to the system planning requirements contained in Order 890. The Final Rule largely adopts the proposals made in the NOPR which the Commission found necessary, because of changes in the industry, to avoid undue discrimination and to remove barriers to the development of transmission facilities in regional planning and cost allocation practices. These additional requirements are intended to build upon the Planning Principles required under Order 890. The Final Rule contains additional requirements regarding regional and interregional planning procedures and cost allocation, adds "public policy considerations" to the existing requirements regarding planning for reliability and economics, and requires the removal of so-called federal "right of first refusal" (ROFR) provisions for incumbent transmission owners contained in many existing Tariffs.[105]

Since the Commission rejected multiple protests challenging its authority to require interregional planning and cost allocation as well as the removal of the ROFR provisions, there were numerous challenges on rehearing to the Final Rule. On September 14, 2011, FERC issued a tolling order and has not yet addressed the rehearing petitions.

10.2 Highlights of the Final Rule

The Final Rule follows the approach used in Order 890 in that it does not require a generic nation-wide approach, but provides for regional flexibility. Each Transmission Provider, including ISOs and RTOs, is

[102] Refer to Section 4 of ISO-NE's 2011 Regional System Plan found at: http://www.iso-ne.com/trans/rsp/2011/rsp11_final_102111.doc.
[103] EEFWG materials are available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/index.html
[104] ISO-NE's annual 10-year forecast of capacity, energy, loads, and transmission (CELT) is a source of assumptions for planning and reliability studies. CELT materials are available at: http://www.iso-ne.com/trans/celt/
[105] In the case of New England, a transmission owner asserted that Commission-approved Mobile-Sierra protection for its rights and obligations to build could not be revised by the Commission absent a legal showing that the provisions were not in the public interest, as that standard has been applied in similar Mobile-Sierra cases. The Commission declined to make a determination in the final rule, but rather directed that the case concerning Mobile-Sierra contract protection should be dealt with as part of the ISO-NE / New England transmission owner compliance filing.

to work with its stakeholders to develop compliance filings which reflect regional preferences within the framework required by the Order. Highlights of the Order include:

- Each Transmission Provider must participate in a regional planning process which produces a “plan.”
- Requires consideration of transmission needs which may be driven by “public policy” requirements in planning & for cost allocation
- Cost allocation is based upon a “beneficiaries pay” approach in compliance with 6 “principles”
- Each Transmission Provider must develop with each of its neighbors, in conjunction with stakeholders, an inter-regional transmission planning process, including inter-regional cost allocation.
- A project must be adopted by both regional plans to be eligible for inter-regional cost allocation
- Retains a “FERC backstop” if agreement cannot be achieved on cost allocation
- Does not require multi-regional or interconnection-wide planning or cost allocation
- Eliminates federal Right-of-First-Refusal (“ROFR”) tariff provisions—with some exceptions (e.g. – upgrades on existing ROWs). This provision does not impact state laws that may provide a right of first refusal.

10.3 Specific Requirements

10.3.1 Transmission Planning Requirements

10.3.1.1 Regional

Each Transmission Provider (TP), including ISOs and RTOs, must participate in a regional transmission planning process that meets Order 890 requirements and produces a regional transmission plan. The regional plan must reflect solutions that meet the region’s needs more efficiently or cost effectively than the local plans. In addition to reliability and economic projects, local and regional transmission planning processes must “consider” transmission needs driven by public policy requirements established by state or federal laws or regulations. Stakeholders must have an opportunity to participate in identifying and evaluating potential solutions to regional needs.

10.3.1.2 Inter-regional

Transmission Providers must work with their neighbors and stakeholders to develop an interregional transmission planning process to determine if there are more efficient or cost-effective solutions to the transmission needs of both regions. While multi-regional or interconnection-wide planning is not required, it is encouraged. Transparency and stakeholder participation is required, but the interregional planning process is not required to produce a “plan” or to fully comply with Order 890’s planning principles.

10.3.2 Transmission Cost Allocation Requirements

10.3.2.1 Regional

Each region must have a regional cost allocation method for new transmission selected in a regional transmission plan for the purposes of cost allocation. This method must satisfy six regional cost allocation principles:

1. Allocation of costs within region must be at least “roughly commensurate” with benefits
2. Those entities that do not benefit must not be allocated any costs

3. If a benefit/cost ratio is utilized to determine the value of projects that proceed, it can be no greater than 1.25
4. The allocation method for costs of a regional facility must allocate costs solely within the region unless another entity outside the region voluntarily agrees to pay a portion of the costs
5. The cost allocation methodology and identification of beneficiaries must be transparent to all stakeholders
6. Different cost allocation methodologies may be used for different types of transmission facilities (e.g., reliability, economic, public policy)

10.3.2.2 Inter-regional

Transmission providers in neighboring regions must have a common interregional cost allocation method for new interregional transmission that both regions determine to be more efficient or cost-effective than regional solutions. The interregional cost allocation methodology may be different from the respective regional methodologies. Multi-regional or interconnection-wide cost allocation is not required. This method must satisfy the six inter-regional cost allocation principles, which are as follows:

1. Allocation of costs to be "roughly commensurate" with benefits
2. Those who do not benefit must not be allocated any costs
3. Costs cannot be involuntarily allocated to a region in which that facility is not located
4. If a benefit/cost threshold multiplier is utilized, it can be no greater than 1.25
5. The cost allocation methodology and identification of beneficiaries must be transparent to all stakeholders
6. Different cost allocation methodologies may be used for different types of transmission facilities (e.g. – reliability, economic, public policy)

Participant funding of new transmission facilities will be permitted, but case-by-case determinations of cost allocation is not allowed as the regional or interregional cost allocation method. The Final Rule does not require a one-size-fits-all method for cost allocation and allows each region to develop its own methods. However, if the region(s) cannot decide on a method, then FERC would decide based on the record submitted with the compliance filings.

10.3.3 Nonincumbent Developers: Right of First Refusal (ROFR)

The Final Rule requires the elimination from Commission-approved tariffs of any federal right of first refusal for incumbent transmission owners to build and own transmission with respect to new transmission facilities selected in a regional transmission plan for purposes of cost allocation. This prohibition does not apply to upgrades of existing facilities or on existing rights-of-way. The Order allows, but does not require, the use of competitive bidding to solicit transmission projects or project developers. Tariffs must include specific qualifications, applicable to both incumbents and non-incumbents, to establish eligibility to propose a transmission project for consideration in a regional plan. State or local laws or regulations regarding the construction of transmission facilities, including authority siting or permitting, are not affected by this Rule. Tariffs must include a mechanism to evaluate the cause of delays and alternatives so that project developers and incumbents can proceed with their projects in the event of project delays, or else FERC will provide a backstop to evaluate project delays.

10.4 Implications for the Northeast

The Northeast ISO/RTOs' existing reliability and economic planning processes, including cost allocation, are already largely compliant with the requirements of the Order, although future compliance filings are required. While the ISO/RTOs already include some consideration of public policy in their planning process, there will likely be some tariff modifications needed to comply with the Final Rule.

The cost allocation principles adopted in the Final Rule re-affirm the "beneficiaries pay" philosophy which was the foundational principle established in Order 890. Each of the Northeast ISO/RTOs has been found compliant with Order 890 with respect to reliability and economic projects.

The Northeast Planning Protocol already contains many of the inter-regional planning elements now required under Order 1000. With respect to inter-regional cost allocation, the Commission reaffirmed that no region can impose cost allocation on another region—for a facility that is not located in that other region--without that region's consent. The Final Rule does require the ISO/RTOs to develop an "ex ante" inter-regional cost allocation methodology between each pair of neighboring regions. The Northeast ISO/RTOs plan to leverage the existing Northeast ISO/RTO Planning Coordination Protocol to address the inter-regional planning and cost allocation requirements of the Final Rule.

The Northeast ISO/RTOs existing tariffs address the ROFR issue in different ways. There will likely be some tariff modifications needed with respect to the qualifications for non-incumbents to submit transmission proposals for consideration in the ISO/RTOs' planning processes.

10.5 Effective Date & Compliance Filings

T he Effective Date of the Final Rule is October 11, 2011. Compliance filings on all issues, except for inter-regional issues, are due on October 11, 2012. Compliance filings on inter-regional planning and cost allocation are due on April 11, 2013. The new requirements of Order 1000 will apply to "new transmission facilities" arising from local or regional transmission planning processes after the effective date of the compliance filings (e.g. – after FERC approval).

11 Plans for Additional JIPC Analysis

11.1 Coordination of Databases, Modeling, and Simulation Tools

The JIPC will continue to directly coordinate data bases and improve its modeling tools used in resource adequacy, market efficiency, and transmission planning analyses. The JIPC will build upon the successful sharing of information that has already improved the ISO/RTOs understanding and ability to model variable resources and to develop long-term forecasts of energy efficiency. The common use of Ventyx economic databases by the ISO/RTOs will facilitate coordinated and joint production cost studies. Other information on simulation techniques and tools will continue to be shared.

11.2 Market Efficiency Analysis

As indicated in Section 3.2, market efficiency analysis for the PJM/ISO-NE/ NYISO service territory is ongoing and significant progress has been made in the coordination of the joint production cost database. Examination of the high level results produced to date has demonstrated that they are consistent with current market conditions. Additional work that is currently planned includes updating ISO/RTO transmission models to reflect 2012 system plan topologies, update boundary modeling for regions external to PJM/NYISO/ISO-NE, further benchmarking and refinement of LMPs and flows, and examine the benefits of increased transmission tie capacity.

Additional market efficiency studies using a coordinated database will be conducted to quantify the benefits of increased imports to New England from the neighboring Canadian regions. These studies would reflect planned and potential transmission system improvements in all three ISO/RTOs.

11.3 Transmission Analysis

While market efficiency studies conducted to date have not identified the need for transmission upgrades, the JIPC remains alert to future opportunities or needs that may be identified as these studies continue to progress. In addition, the JIPC will continue to coordinate the various efforts associated with a number of new interregional merchant transmission projects and generator interconnections that are currently in various stages of development, and will similarly coordinate these efforts as system improvements are planned within individual systems. Further, in collaboration with the work conducted in various interregional planning forums – including NERC, NPCC, IRC, and EIPC – the JIPC will continue to coordinate interregional studies and assess transmission system improvements.

11.3.1 Short Circuit Analysis

Internal PJM short circuit analysis of northern New Jersey indicates that fault current is approaching the limit of current circuit breaker technology. Duties exceeding 80 kA in New Jersey are projected beginning in or around 2016. Since NYISO and PJM regularly exchange internal system representations and due to the close electrical interactions of the affected load centers on both sides of the interface, NYISO and PJM will perform a coordinated short circuit analysis that seeks to investigate regional modeling and methodology differences so that short circuit results may be better understood across regional boundaries.

The JIPC will perform a joint PJM and NYISO assessment of the short circuit duty on the Bulk Electric System in the PSEG and ConEd areas. The objectives of the assessment will be to: (1) address regional differences in short circuit study practices, (2) establish a joint short circuit model with updated topology and breaker information, (3) perform and review short circuit analysis, and (4) if necessary, evaluate potential short-term and long-term mitigating actions to address identified issues.

This analysis is expected to be completed by the middle of 2012. Upon completion of the study a report documenting the joint analysis and results will be produced and presented to the IPSAC.

11.4 Transmission Planning and Cost Allocation

Pursuant to Order 890, FERC currently requires that all jurisdictional transmission providers have formal planning processes that include both economic and reliability planning as well as cost allocation provisions for each, and all ISO/RTOs have FERC-accepted protocols for satisfying these requirements in their respective tariffs. A summary of current cost allocation philosophies and practices of PJM, NYISO, and ISO-NE is provided in Section 13.1.

FERC's Order 1000, issued in July 2011, follows the approach of Order 890 in that regional flexibility is allowed rather than a generic nation-wide approach. Each Transmission Provider, including ISOs and RTOs, is to work with its stakeholders to develop compliance filings which reflect regional preferences within the framework required by the Order. As part of FERC Order 1000 (discussed in Section 9) Transmission Providers in neighboring regions must have a common interregional cost allocation method for new interregional transmission that both regions determine to be more efficient or cost-effective than regional solutions. The interregional cost allocation methodology may be different from the respective regional methodologies. The ISO/RTOs plan to consider the benefit metrics employed in each region in developing a proposed cost allocation methodology for regional projects for future stakeholder discussions.

The Northeast Planning Protocol already contains many of the interregional planning elements now required under Order 1000. The Northeast ISO/RTOs plan to leverage the existing Northeast ISO/RTO Planning Coordination Protocol to address the inter-regional planning and cost allocation requirements of the Final Rule. Compliance filings on all issues, except for inter-regional issues, are due on October 11,

2012. Compliance filings on interregional planning and cost allocation are due on April 11, 2013. The JIPC is currently developing protocols to meet Order 1000's requirements, and will continue to work with stakeholders and coordinate their efforts in order to satisfy upcoming compliance filings. Documentation of regional planning practices will be provided, including those related to energy efficiency and demand response, and harmonization of those practices will be considered to the extent feasible while providing compatibility with the respective ISO/RTO regional markets.

11.5 Multi-Regional Gas/Electric Study

Significant increased reliance on natural gas as the primary fuel for new power plants has raised concerns on the part of ISO/RTOs, market participants and regulatory commissions regarding the adequacy of the natural gas infrastructure to meet the coincidental requirements of gas utilities and generators. Whereas gas utilities' service obligations are synonymous with core loads, generators requiring natural gas are usually associated with non-core load. Concerns over adequate pipeline and storage infrastructure to serve the simultaneous fuel requirements of core and non-core shippers alike are heightened during the heating season, November through March. Typically, the peak heating season, December through February, corresponds to the most extreme temperature conditions experienced in the Northeast and therefore the period when congestion is most likely to occur on the pipelines serving market centers across Ontario, New England, New York and the Mid-Atlantic States. Peak gas use for electric generation occurs in the summer months. There are several known instances where generation was derated or not able to run because of gas supply issues. As an example, combustion turbines in New York City were unable to operate because of a compressor station failure in western Pennsylvania. Similar experiences have occurred in New England.

With massive new discoveries of natural gas in deep shale formations near Northeastern load centers, decreasing allowable emission levels, tightening of the spread between the cost of gas and the cost of coal and heightened concerns over nuclear generation, it is expected that there will be a significant increase in the use of natural gas for electric generation. Considering this expected increase and past experience of units being derated because of gas pipeline limitations, it would be highly beneficial to update the Multi-Region Assessment of the Adequacy of the Northeast Natural Gas Infrastructure to serve the Electric Power Generating Sector gas study that was conducted in 2003 (aka, the 2003 multi region gas study). The ISO/RTOs and affected utilities are pursuing such an update to be performed in 2012-2013. The JIPC will monitor the developments of this study.

11.6 Tracking Environmental Regulations

The development and implementation of several major EPA and regional environmental regulations, including those regarding ambient air quality, greenhouse gases (such as carbon dioxide), air toxics, coal ash and cooling water are raising various issues that the ISO/RTOs are evaluating and addressing through studies and planning processes pursuant to their respective tariffs and in consultation with affected stakeholders.

These regulations could materially affect various electric power generators beginning in 2012 and continuing through 2020, when many affected facilities are required to come into compliance. When finalized, based on EPA estimates, these regulations could affect a significant amount of installed fossil and, in the case of cooling water, nuclear capacity across the Northeast. Compliance with this suite of environmental regulations, in some cases, will entail significant capital investment for retrofitting facilities with post-combustion control devices, closed-cycle cooling systems, or fuel-switching equipment, or retiring electric generators.

Generator capital, operation and maintenance costs are expected to increase for many affected units because of the aggregate impact of these regulations. Those increased costs will include new emission allowances, new pollutant controls, increased waste disposal, and cleaner fuels. These environmental regulations may also affect reliability by limiting generator energy production, reducing capacity output, hastening generator retirements. Since interregional system performance could change as a result of new generation patterns, the JIPC monitors environmental regulations for potential system impacts.

12 Summary and Conclusions

12.1 Summary

The studies and activities discussed in this report demonstrate that considerable proactive interregional planning is being performed by ISO-NE, NYISO, and PJM. The ISO/RTOs develop their system plans, conduct economic studies, and perform interconnection studies accounting for the modeling of neighboring regions and interregional system performance. The ISO/RTOs planning efforts have resulted in interregional system assessments, the addition of new transmission ties between the regions, and the integration of new generator interconnections near the border areas. The ISO/RTOs are addressing common interregional issues and studies that include:

1. Shared studies, databases, critical contingency lists, short-circuit equivalents, and others
2. The identification of improved planning techniques, modeling, and software tools
3. Coordinated interconnection queue studies and transmission improvements
4. Completed market efficiency studies and initiated new studies using IREMM and PROMOD reflecting coordinated system models
5. Evaluations of environmental regulations and their potential effects on the power system
6. Identification of issues and solutions facilitating the integration of intermittent resources
7. Identifying and addressing fuel diversity issues, including coordinated studies of the natural gas system
8. The effect of demand-side resources on interregional planning
9. Broader interregional planning activities through NPCC, NERC, and EIPC.
10. Coordination on compliance with Order 1000, particularly on interregional planning and cost allocation issues

12.2 Conclusions

ISO-NE, NYISO, and PJM have continued to proactively plan the interregional system under the Northeastern ISO/RTO Planning Coordination Protocol. The scope of work, assumptions, and review of draft study results are subject to open stakeholder review provided by the IPSAC. The desirability of performing specific studies and the need to address several issues have been identified and their status will be discussed at future stakeholder meetings.

While much has been accomplished under the protocol over the past several years, both the ISO/RTOs and their stakeholders recognize that much remains to be done to further advance and enhance interregional planning for the Northeast and beyond. The Northeast ISO/RTOs are largely compliant with Order 1000, but are actively working to further improve the interregional planning processes in collaboration with their stakeholders.

13 Appendices

13.1 Cost Allocation Matrix of ISO/RTOs

This section provides a summary of the cost allocation methods of PJM, NYISO, and ISO-NE.

PJM	**PJM -- Cost Allocation Philosophies and Practices**	
	EXISTING	**UNDER CONSIDERATION**

Reliability
 	
Upgrades
	▪ **RTEP baseline facilities at or above 500kV voltage level**
	- Also includes costs of those related facilities below 500kV needed to support a 500 kV upgrade.
	- Considered "Regional Facilities" by FERC – region-wide allocation
	- Load ratio share at time of EACH ZONE's annual peak of previous year ending October 30
	- Merchant transmission share based on firm transmission withdrawal rights the year after in-service, or previous year's peak usage otherwise per respective Interconnection Service Agreements.
	
	▪ **Baseline BELOW 500kV**
	- General
	  - If cost estimate < $5 million, costs allocated to zone where upgrade is required
	  - If cost estimate >= $5 million, costs allocated based on distribution factor (DFAX) analysis; DFAX percentages based on zonal load and merchant transmission firm withdrawal rights
	- Lines, Transformers, etc.
	  - Allocate based on impact of each TO zone on the constrained facility, i.e. (change in power flow due to that TO zone) / total power shift on constrained facility)
	- Circuit Breakers (CBs)
	  - If need associated with a planned transmission upgrade, allocate CB cost as part of that upgrade;
	  - If need is independent of any other planned transmission system upgrade, cost allocated to zone in which CB is located
	
	▪ **PJM / MISO Cross-Border Baseline Reliability Project**
	- Transfer distribution factor (DFAX) analysis to calculate each RTO's flows affecting a constrained facility that a proposed cross-border facility is to relieve
	- Minimum of $10 million cross border allocation
	- Total net flow of each RTO on a constrained facility, i.e. (all positive flow) less (all counterflow)
	- After cross-border facility costs are allocated to each RTO, each RTO then allocates internally according to its own OATT.	

Economic Upgrades	▪ **AT OR ABOVE 500kV** - Load ratio share at time of EACH ZONE's annual peak of previous year ending October 30 - Merchant transmission share based on firm transmission withdrawal rights, per respective ISAs. ▪ **BELOW 500kV, ECONOMIC ONLY** - Allocated to the benefiting zones in proportion to their benefit based on their decrease in net present value of cost to serve load net of FTRs for 1st 15 years of the project. Merchant withdrawals participate in the calculation based on their change in present worth net load payments the same as a load. ▪ **BELOW 500 kV, modifications to reliability upgrades already in RTEP** - Cost allocation based on distribution factor methodology, as discussed above ▪ **BELOW 500 kV, accelerated reliability upgrades already in RTEP**. Compare allocation factors based on: [1] DFAX; [2] LMP benefit over acceleration period based on load payments by LSEs; if differential >= 10%, use relative LMP benefit; otherwise, use DFAX methodology ▪ PJM / MISO Cross-Border Market Efficiency Project Total cost of a qualifying project is allocated to the RTO's based on their proportional share of the sum of project present worth of total net benefits, for a minimum of 10 years, using the bright line metric that qualified the project.	-

<table>
<tr><th rowspan="2">NYISO</th><th colspan="2">NYISO -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Reliability

Upgrades</td><td>

NYISO “all source” planning process

Reliability needs identified; solutions from marketplace solicited; transmission, generation and demand response on a level playing field
NYISO evaluates all proposed solutions against needs but does not pick any specific solution; explicit preference is given to market-based solutions
Regulated backstop solutions, provided by TOs, can be triggered if market-based solutions are not available
NYPSC reviews regulated backstops and alternative regulated proposals and determines which should go forward

Cost allocation philosophy…beneficiary pays

Regulated Reliability Transmission Projects: Applicable to projects triggered prior to 1/1/2016, after which NYISO to propose continuation or another alternative approach. NYISO uses a 3-step approach based on scope of area that has requirement for installed capacity: (1) Locational Need; (2) Statewide need; (3) Bounded Region / Constrained Interface Need. Based on a 1-day-in-10-years loss-of-load-expectation standard and beneficiary pays principle;

<u>Locational Need:</u> i.e., NYC and Long Island - 100% of costs allocated to LSEs in respective zone(s). Then, Step 2.
<u>Statewide Need:</u> i.e., New York Control Area - reliability upgrades necessary to bring control area to 1-day-in-10 reliability, under UNCONSTRAINED system, i.e., all transmission constraints relaxed; allocation to all load zones in control area based on load ratio share of control area coincident peak; zonal credits for meeting locational capacity requirements where locational upgrade cost allocation offsets statewide reliability upgrade cost allocation. If Step 2 is invoked - i.e., upgrades triggered under this test – then methodology stops with this Step; otherwise move on to Step 3
<u>Bounded Region / Constrained Interface Need</u>: determine zones with binding interfaces, preventing sufficient capacity from being deliverable throughout the control area; “compensatory MW” added to bounded region based on greatest LOLE impact to reach 1-day-in-10 standard; successive iterations run until 1-day-in-10 is achieved across control area; compensatory MW are allocated to zones within a bounded region based on zonal contribution to control area coincident peak; <u>“compensatory MW”</u> are resources required to fulfill identified need and can be transmission, generation and/or demand response solutions.

Regulated Reliability NON-TRANSMISSION Projects: “Costs…will be recovered by [Transmission Owners] and other developers in accordance with the provisions of …state law.” On June 26, 2009, the NY Public Service Commission revised its previously issued Policy Statement to adopt a cost allocation mechanism for regulated NON-TRANSMISSION reliability projects that is consistent with that approved by FERC for regulated

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Order 1000 will require modifications to the NYISO’s planning process although no changes to the cost allocation for reliability upgrades is anticipated.

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	transmission reliability projects under the NYISO Tariff so that all solutions are considered on an equal basis	
Economic Upgrades	▪ NYISO's planning process includes a procedure for the analysis and posting of historic congestion information . ▪ NYISO Congestion Assessment and Resource Integration Study ("CARIS"): - Phase I "Study Phase": NYISO first determines the three most congested elements on the transmission system, prioritized in consultation with stakeholders based upon historic data and a 10-year projection. NYISO then analyzes potential generic solutions to congestion over a 10-year period. All resources are considered as potential solutions. Threshold B/C ratio is based upon statewide production cost savings compared to total estimated project revenue requirements over ten years. NYISO also calculates zonal locational based marginal cost savings ("LBMP"), losses, generator costs, emissions, transmission congestion contracts and other metrics. Scenario analysis, based on stakeholder input, is also conducted during this Phase. - Phase II "Project Phase": During this phase, developers may submit proposals for regulated economic transmission projects to the NYISO for consideration for cost recovery under the NYISO Tariff. . The evaluation conducted is over a 10-year period starting with the projected in-service date for the project and compares the statewide production cost savings to the total estimated project revenue requirements (provided by the developer) as the eligibility metric. LBMP savings by zone is also computed and additional metrics similar to those used in Phase I are provided for information only. Scenario analysis is also provided based on stakeholder input. - The cost of regulated economic transmission projects allocated to load based on the zonal share of total LBMP savings (net of TCC revenues and bilateral contracts). At least 80% of beneficiaries must vote in favor of the project in order to be eligible to receive regulated recovery under the NYISO tariff. Developer must file revenue requirements with FERC upon completion of project. NYISO collects the revenues from the beneficiaries on a monthly basis.	- Order 1000 will require modifications to the NYISO's planning process although no changes to the cost allocation for economic upgrades is anticipated.

<table>
<tr><th rowspan="2">ISO-NE</th><th colspan="2">ISO-NE – Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Reliability Upgrades</td><td>

Reliability Benefit Upgrades (RBU):

115 kV or above;
Meet definition of Pool Transmission Facilities (“PTF”); and
Be included in Regional System Plan as either a Reliability Transmission Upgrade (RTU) or a Market Efficiency Transmission Upgrade (METU).

RBUs are eligible for regional cost recovery as part of “Pool-Supported PTF costs”

Must meet PTF definition based on ISO review of transmission plans submitted by market participants and TOs;
ISO determines Localized Costs – “the costs of transmission upgrades that exceed reasonable requirements . . . shall be deemed Localized Costs.” Localized Costs are not included in the Pool-Supported PTF costs. Determination based on ISO assessment of proposed engineering design and construction methods and practices, alternative upgrades, allowance for expansion and load growth, as well as relative costs, timing, implementation, efficiency and reliability of proposed upgrades.
Pool-Supported PTF costs (i.e., those not localized) are allocated region-wide.

RBUs: are those “…upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards.”

</td><td>
[No modifications presently under consideration.]
</td></tr>
<tr><td>Economic Upgrades</td><td>

Market Efficiency Transmission Upgrade (METU) “upgrades designed primarily to provide a net reduction in total production cost to supply the system load.” “[D]esigned to reduce bulk power system costs to load system-wide; …net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade; …“bulk power system costs to load system-wide” includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.”

METU costs that meet RBU criteria are included in the Pool-Supported Costs.
METUs that are not RBUs are not included in the Pool-Supported PTF Costs.

</td><td>
[No modifications presently under consideration.]
</td></tr>
</table>

	- By definition, neither METUs nor RBUs are "related to the interconnection of a generator," unless determined otherwise under Schedule 11.	

13.2 References

The Northeastern ISO/RTO Planning Coordination Protocol can be found at: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/rto_plan_prot/planning_protocol.pdf

Industry links to websites of other ISO/RTOs, federal and state energy agencies, and private industry groups are available at: http://www.iso-ne.com/support/indlinks/index.html

NPCC reports and reviews can be found at:
https://www.npcc.org/Library/default.aspx

RFC Reliability Reports can be found at:
https://www.rfirst.org/reliability/Pages/ReliabilityReports.aspx

For ISO-NE stakeholders:
Materials for the IPSAC meetings are posted on the IPSAC site:
http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/index.html
The digital certificate required for access to Critical Energy Infrastructure Information (CEII) IPSAC materials is the same as that required for PAC materials. If you do not have access to the ISO-NE IPSAC site, please contact the ISO's Customer Service Department at (413) 540-4220.

For PJM Stakeholders:
Materials for the IPSAC meetings are posted at: http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/ipsac-ny-ne.aspx

For NYISO stakeholders:
NCSP reports, related documentation, and meeting material are posted at:
http://www.nyiso.com/public/markets_operations/services/planning/groups/ipsac/index.jsp