Final

03-27-09

2008 Northeast Coordinated Electric System Plan

ISO New England, New York ISO and PJM

Contributors:

ISO-NE: M. Henderson, J. Platts, W. Henson, M. Garber

NYISO: J. Adams, J. Buechler, P. Carney, W. Lamana

PJM: P. McGlynn, M. Nix, G. Velummylum, M. Osman

Table of Contents

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). The report also includes discussion of the Northeast Power Coordinating Council (NPCC), the Reliability*First* Corporation, and the North American Electric Reliability Corporation (NERC).

1. Executive Summary

ISO New England (ISO-NE), New York ISO, and 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 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 New England (ISO-NE), New York ISO, 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, Independent Electric System Operator (IESO) of Ontario and the New Brunswick System Operator 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 on a periodic basis
- 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 group formed the Joint ISO/RTO Planning Committee (JIPC) and an open stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC).[2] Through the open stakeholder process, the JIPC has addressed several interregional balancing authority area issues over the past year, including:

- The addition of transmission upgrades, including new ties that increase the transfer limits between the ISO/RTOs
- The coordination of interconnection queue studies and transmission improvements to ensure reliable interregional planning
- Cross-border transmission security issues, including the consideration of loss-of-source (LOS) contingencies, and limiting constraints in the Northeast
- Improvements in modeling and performance of studies that have improved the quality of resource adequacy studies

[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 is responsible for a wide geographic area known as a balancing 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, and the District of Columbia.

[2] See “Inter-ISO Planning,” IPSAC meeting notices; http://www.interiso.com/default.cfm.

- Impact of wind and other renewables on interregional operations and planning
- Fuel diversity and operation under fuel-shortage situations
- Impact of environmental regulations

Interregional planning starts with the latest regional plans of the three ISO/RTOs. These plans are summarized in this report along with the interregional planning activities and issues listed above. The report also discusses completed analyses, current issues, and the scope of work for future interregional planning efforts. Planning across interregional boundaries coordinates the timing of particular projects internal to regions, avoids redundancy in the functionality of projects planned in individual regions, and identifies joint projects that can solve problems on a wide-area basis.

As part of the latest ISO/RTO regional plans, these inter-regional studies included two inter-area ties which have recently gone into service: the Northeast Reliability Interconnect Project, consisting of a second tie line between New England and New Brunswick, and a replacement cable upgrading the existing underwater Long Island Cable 1385 tie between Norwalk, Connecticut, and Northport, New York. The studies also include the Neptune Project, a new merchant interconnection between PJM and Long Island.

Loss-of-Source (LOS) studies are important examples of interregional planning that impacts the three ISO/RTOs. These studies simulate the normal planning criteria loss of generating units and HVDC interconnections to determine interregional operating limits and evaluate opportunities to increase these 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.[3] During many periods, the 1,200 MW limit was 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 and 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

Studies that examined the possibility of increasing the NYISO and PJM limits showed that "quick fixes", such as the addition of series reactors on the New York-to-New England tie lines, are not feasible. Long-term system improvements planned in New York and PJM that have been recently assessed include:

- New generating resources in the Hudson Valley
- Improvements in PJM 500 kV and 765 kV facilities that will increase the ability to transfer power from the west to the east
- New merchant transmission tie lines between New York and PJM
- New ties between New York and New England
- Other transmission improvements in New York, New England, and PJM

While the assessment shows an increase in the permissible loss-of-source limit for New England above 1,200 MW up to a 1,500 MW to 1,600 MW range due to contingency restrictions within New York,

[3] Consistent with planning criteria, loss-of-source contingencies take into consideration the forced outage of resources that are supplying power to the system.

constraints in PJM will likely limit the LOS contingencies to 1,400 MW to 1,500 MW. The possibility of additional system improvements in New York, PJM, and New England will be explored in the future to determine whether an increase of the LOS limit above the 1,400 MW level is possible.

One goal of the JIPC is to proactively plan system improvements that address both regional and interregional issues. One such prefeasibility study is the consideration of a new tie between Plattsburgh, NY, and the Burlington area of VT. This study scope addresses:

- The need for long-term transmission sources for Vermont, particularly for the Burlington area, consistent with the Vermont ten-year plan
- The desire to increase the loss of source limits for New England and to improve the overall reliability of the interregional transmission system
- The improvement of restrictive transfer limitations on the New York Central East interface
- A means of increasing the transmission transfer capability out of New York's North Country and with it, increased access to planned wind resources in that area

The queue for renewable resource development in the three ISO/RTO regions totals about 65,000 MW, over 93% of which is wind, including significant offshore wind projects. This growth of wind resources creates system integration and operating challenges for all three ISO/RTOs. This includes transmission development to interconnect wind projects, system operating flexibility to accommodate wind's variability, operator awareness and practices, and the need for wind generator plant performance and standards. The JIPC provides an avenue for the ISO/RTOs to share solutions to these issues.

In addition to wind development in the three ISO/RTOs, two scenarios that consider imports of large amounts of wind energy and coal from the Midwest have been studied in the Joint Coordinated System Plan (JCSP). This group is led by the Midwest ISO, and includes representatives from much of the Eastern Interconnection, including PJM. Similar scenario analysis involving hundreds of cases is being undertaken by ISO New England for wind and hydro imports from Eastern Canada as well as other scenarios that include demand resources. The operating challenges of implementing wind forecasting systems and providing adequate system regulation are being evaluated separately by the three ISO/RTOs, the Department of Energy (DOE), and the North American Electric Reliability Corporation (NERC). Many of the Northeastern states are also promoting demand resources and their use is reflected in each of the ISO/RTOs planning processes and markets. NCSP analyses have accounted for demand resources (DR) and future work will evaluate their application to resolving reliability, economic and environmental issues in each and across the regions.

The IPSAC recognizes the need for further work that is coordinated through the JIPC. Future plans call for conducting additional interregional transmission reliability and economic analyses that may identify potential transmission bottlenecks and identify the benefits of market efficiency upgrades for system improvements. In addition, cross-border transmission cost allocation discussions are planned following completion of the studies outlined in Section 9 of this report. The ISO/RTOs regularly provide the status of "seams issues" including the schedules for addressing the planning issues and studies identified in this report. The Seams Report is noticed by the FERC[4].

Planning is subject to many uncertainties, revised forecasts, and applications of new technologies. Because planning is continuous, the NCSP results and activities represent a snapshot in time that will require ongoing input from stakeholders. The results of studies that identify the year of need for some

[4] The Seams Report can be found on at the following link: http://www.iso-ne.com/regulatory/seams/2008/index.html.

transmission projects may be driven in whole or in part by load levels. A new year of need can be identified using the results of some NCSP studies by referencing revised load forecasts. For example, in some cases lower load forecasts or use of conservation and load management can postpone the need for projects in load pockets. However, a lower load forecast and/or conservation and load management in export-constrained areas or areas that experience high voltage conditions may advance the need for transmission improvements. The JIPC will continue to coordinate planning issues and efforts across ISO/RTO boundaries and remain alert to changes in system conditions and forecasts. Planning activities will include the impact of the recent economic downturn on load and fuel supply as well as environmental regulations and renewable integration issues[5]. The use of new technologies, such as smart grid and related metering technologies, will be considered and their application along with the aforementioned factors will influence the need and timing of future transmission development.

Interregional studies are increasing in importance and the need for studies of the planned 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* Corp. (RFC), the North American Electric Reliability Corporation (NERC), and the ISO/RTO Council (IRC). The IRC provides joint policy direction regarding issues of common interest to the individual ISO/RTOs. 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 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.

[5] On February 5, 2009, the Energy Information Administration reported that nationwide fourth-quarter 2008 electric energy consumption had decreased by a full 1%.

2. Introduction

The New York Independent System Operator (NYISO), ISO New England (ISO-NE), and the PJM Interconnection have been coordinating system planning since they were formed. In the fall of 2003, they 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 the 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, which was formalized in December 2004 and subsequently filed with FERC. The Joint Interregional Planning Committee (JIPC) carries out the coordinated planning of the combined ISO-NE, NYISO and PJM systems and an 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 interconnected power system over the broader Northeast region. Planning activities are also 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 2005 and periodic updates were provided to the IPSAC. For example, improved interregional coordination of fuel diversity issues has improved the overall reliability of the interconnected network. Other issues that were coordinated by the JIPC and discussed with IPSAC included environmental regulations, coordination of interregional resource adequacy and transmission studies, and other analyses.[6] This document is an update on some of the interregional activities occurring since the previous report was issued.

This report is organized as follows: Section 3 provides summaries of the ISO/RTO's annual regional plans. Section 4 summarizes the interregional studies. Section 5 covers additional coordinated planning activities and issues. Section 6 covers wind and renewable resource studies. Section 7 summarizes the key environmental issues potentially affecting interregional impacts among the three ISO/RTOs. Section 8 summarizes the renewable portfolio standards (in the states that have them) and the proposed renewable resources located in those states that could meet these standards. Section 9 discusses the application of demand resources and Section 10 describes plans for additional interregional studies. Finally, Section 11 presents conclusions and recommendations and Section 12 contains a matrix that provides additional information on the existing transmission cost allocation methods for all the ISO/RTOs.

The planning studies discussed in this report are based on 2008 load forecasts and other projected system conditions. These are updated periodically and coordinated with stakeholder groups.

---

[6] Previous IPSAC studies can be found at http://www.interiso.com/documents.cfm, where meeting presentations and supplemental reports are available for a number of issues.

3. Summaries of RTOs' System Plans

This section summarizes the ISO/RTOs' latest plans covering their resource needs, transmission projects and costs, and seams issues. Because the planning processes are open and continuous, interested stakeholders are encouraged to participate in each of the ISO/RTO planning meetings to obtain the latest information.

3.1 ISO-New England 2008 Regional System Plan

ISO New England 2008 Regional System Plan (RSP08) was published October 16, 2008. It shows a forecasted annual average peak load growth of New England of 1.2 %, with the peak projected to increase from the annual peak of 27,460 MW in 2007 to 31,250 MW in 2017. In 2008, ISO New England conducted its first Forward Capacity Auction for the year 2010 and this resulted in 34,077 MW of generation and demand response resources clearing the auction. If all these resources are still committed and operating in 2010 and beyond, they would be sufficient to meet the resource adequacy needs through 2014. This amount includes a total of 2,554 MW of demand response resources. If there were no other changes to these capacities, New England would need an additional 982 MW of resources by 2017.

Since 2002, over 200 transmission projects have been completed. The October 2008 Transmission Project Listing shows a total of 253 transmission projects are planned throughout New England, eight of which are major projects.

In addition to providing information on the New England region's load forecast, resource adequacy outlook, and transmission needs, RSP08 includes discussions of:

- The need for fuel diversity and how the region is responding to its dependence on natural gas resources
- Challenges and approaches for successfully integrating demand and wind resources
- Environmental issues that will be key drivers for future resource development in the region
- Results of production and environmental analyses that provide information to stakeholders
- Coordination of planning efforts on an interregional planning basis and regional initiatives

The region's heavy reliance on natural gas as the dominant generator fuel type has left the region vulnerable to fuel-supply risks, which can have an adverse impact on system reliability and lead to volatile and high electric energy costs associated with variations in natural gas prices. The region has taken several measures to improve the reliability of the fuel supply, generator availability, and fuel diversity. These include adding new natural gas supply infrastructure, such as liquefied natural gas (LNG) import terminals, and increasing the dual-fuel capability of existing generating units. This capability is especially important as the region has over a 40-percent dependency on natural gas as a fuel and dual-fuel capability adds fuel flexibility during winter periods when peak gas heating demand can coincide with winter electrical peak demand. These measures also include developing and implementing operating procedures that have improved the ISO's coordination of power system operations, both with the natural gas system and with neighboring electric power systems. Over the long term, the development of wind, other renewable resources, and demand resources would provide some of the needed diversification of the region's electric energy supply. This potentially would mitigate exposure to fuel disruptions and high electric energy costs associated with high natural gas prices. The addition of transmission ties to neighboring systems could also provide access to diverse resources including renewables.

3.2 NYISO 2008 Comprehensive Reliability Plan

The 2008 Comprehensive Reliability Plan (CRP) was approved by the NYISO Board of Directors in July 2008. It reports that resource adequacy and transmission security criteria will be met throughout the ten-year planning horizon ending in 2017 by development of at least 2,350 MW of the 3,380 MW proposed market-based solutions. To address specific reliability needs within the state, 1,000 MW of new resources should be located in or available to serve New York City, 1,050 MW should be located in the lower Hudson Valley, and 300 MW can be located anywhere in New York State. All of these resources and their associated transmission improvements are needed to meet a projected annual average peak load growth of 1.2% per year to 2017.

The NYISO received market-based proposals that are over 1,000 MW in excess of the minimum needed to meet resource adequacy and transmission security criteria. The NYISO does not choose which projects will be built; instead, it is up to the proponents to proceed with, and the relevant state and federal siting and permitting agencies to approve, specific projects. The development status of the proposals is monitored on a quarterly basis by the NYISO.

Other milestones identified in the 2008 CRP include actions to:

- Maintain the in-service date for Consolidated Edison’s M29 transmission project, a new 345-kilovolt transmission line from an existing substation in the City of Yonkers to a new substation in Manhattan
- Implement the plans of transmission owners for transmission upgrades, capacity delivery rights, and non-bulk power system projects
- Maintain bulk power system voltage performance, including ongoing review of the factors that affect performance

The report also states that, at this time, New York does not have to implement “regulated backstop solutions” offered by transmission owners or “alternative regulated solutions” submitted by other developers.

The CRP report identifies a number of factors that could affect the plan, which NYISO will closely monitor as part of its ongoing planning process. These include:

- Absence of a streamlined siting process for new generating facilities
- Fuel diversity and fuel supply infrastructure concerns
- Dependence on capacity from neighboring regions
- Value of long-term price certainty for market-based projects
- Potential for additional plant retirements due to economic or environmental factors
- Results of regulations initiated to comply with ozone standards
- Impact of the Regional Greenhouse Gas Initiative (RGGI)
- Effects on electricity demand from implementation of New York State’s Energy Efficiency Portfolio Standard (EEPS)

The 2008 CRP is the culmination of the NYISO’s third planning cycle. In each cycle, the market has responded with project proposals to meet identified reliability needs. More than 3,000 MW of market-based projects, submitted during the NYISO’s first two planning process cycles, are moving forward on schedule.

The NYISO’s 2009 Reliability Needs Assessment (RNA) was approved by the board in mid-January and shows that reliability criteria will be met without the need for additional resources through 2018. This finding is principally due to the addition of nearly 1,700 MW of new generation resources, the anticipated reduction in load of approximately 2,000 MW as a result of state energy efficiency initiatives and an increase of 700 MW in participation in the NYISO’s demand response programs since the issuance of the 2008 RNA.

3.3 PJM 2007 Regional Transmission Expansion Plan (RTEP)

The PJM 2007 Regional Transmission Expansion Plan (RTEP) was published in February 2008. The PJM RTO weather normalized summer peak is forecasted to grow at an average rate of 1.6% annually over the next 10 years – from 136,961 MW in 2007 to 159,822 MW in 2017 – an increase of 22,861 MW over the decade. Individual geographic zone growth rates vary from 0.5% to 2.0%. In developing the RTEP, PJM annually performs comprehensive power flow, short circuit and stability analyses. These assess the impacts of forecasted firm loads, firm imports from and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation and transmission facilities.

The PJM Board has authorized more than $11 billion of transmission upgrades and additions since the inception of the RTEP process in 1997. Nearly $2 billion of this is under construction or already in service. This figure includes more than $5 billion approved in 2007 alone, which is indicative of an accumulated need for backbone remedies. Over $9 billion of baseline transmission network upgrades across PJM ensure that the established reliability criteria will continue to be met.

At the same time, $1.6 billion of additional transmission upgrades will add more than 36,000 MW of new generating resources and accommodate the interconnection of several merchant transmission projects.

PJM 2007 RTEP studies, which included the 2006-approved 502 Junction – Loudoun 500 kV transmission line, revealed that in the absence of additional new high-voltage transmission circuits, NERC reliability criteria violations will be encountered beginning in 2012. Accordingly, PJM’s 2007 RTEP now includes three additional major new backbone transmission lines: Susquehanna – Lackawanna – Jefferson – Roseland 500 kV circuit, Amos – Kemptown 765 kV circuit, and the Possum Point – Calvert Cliffs – Indian River – Salem 500 kV Circuit – Mid-Atlantic Power Pathway (MAPP). The critical need for all three lines is discussed throughout PJM’s 2007 RTEP report. Many other upgrades across PJM, smaller in scope but no less important, were also approved by the PJM Board in 2007 and are discussed in PJM’s RTEP report.

3.4 New Interconnections between the ISO/RTOs

Three new inter-area ties have recently been placed into service. The Northeast Reliability Interconnect Project is a second tie line between New England and New Brunswick. The underwater Long Island Cable (1385) tie between Norwalk, Connecticut, and Northport, New York, was also replaced and upgraded and went into service during the fourth quarter of 2008. The Neptune Project is a merchant transmission line that adds a new HVDC underwater interconnection between New Jersey and Long Island. Several additional new merchant transmission ties are planned between New York and PJM.

3.5 Links to the Regional Plans

Because planning is a continuous function, 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 its own timeline 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. Links to several key regional assessments and plans are provided as references.

The link to the New England Regional System Plan is
http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf

The link to the New York 2008 Reliability Needs Assessment (RNA) is
http://www.nyiso.com/public/webdocs/services/planning/reliability_assessments/2008_RNA__Supporting_FINAL_REPORT_12_12.pdf

The link to the 2008 New York ISO Comprehensive Reliability Plan developed in response to the 2008 RNA is
http://www.nyiso.com/public/webdocs/newsroom/press_releases/2008/2008_Comprensive_Reliability_Plan_Final_Report_07152008.pdf

The link to the New York 2009 Reliability Needs Assessment (RNA) is
http://www.nyiso.com/public/webdocs/newsroom/press_releases/2009/RNA_2009_Final_1_13_09.pdf

The link to PJM's 2007 RTEP Plan is
http://www.pjm.com/documents/reports/rtep-report.aspx

4. Summaries of Interregional Studies

This section discusses all the interregional studies that have recently been completed or are ongoing.

4.1 Loss-of-Source Analyses

This section summarizes the recent loss-of-source analyses and their interregional impacts focusing on the PJM and New York interfaces.

4.1.1 Summary of Previous Analyses

The Loss-of-Source (LOS) analysis seeks to determine the interregional system operating limits for the loss of the largest source across the system. As the system changes with new generation and transmission being added, these limits can potentially change. The IPSAC had requested that 1) the LOS short-term operating limits be confirmed for the New York and PJM systems and 2) system improvements be evaluated that could increase the LOS limit for New England.

The results of the analysis of the 2007 short-term limits showed that contingencies internal to New York and PJM are more constraining than external contingencies, including the New England LOS at 1,200 MW. The New York Central-East (CE) Interface has historically constrained the New York LOS limits to 1,250 to 1,400 MW, while the PJM LOS limits have usually been less restrictive at 1,400 to 1,500 MW. A study of the 2009 system showed that little change in these limits is expected over the next several years. An additional analysis concluded that it does not appear there are any quick fixes to raise the New England LOS, but that major generation and transmission projects may impact the LOS contingencies. The studies considered the addition of series reactors on the New York to New England ties lines, but these provided only small increases in the LOS limit for high capital costs and increased operating complexity. The results suggested that strengthening of the ties between New York and New England should be considered for further study.[7]

This study work continued in 2008 with analysis to assess the Loss-of-Source contingencies on Central East and PJM voltage performance based on the 2012 summer peak system conditions. This analysis was initiated to identify transfer limits on Central East and PJM interfaces for the currently proposed 2012 system and to identify any further transmission reinforcements that would increase these transfer limits. The analysis included consideration of major transmission improvements currently planned for the 2012 timeframe, including TRAIL, PATH and other 500 kV improvements in PJM. The results were presented at an IPSAC meeting held June 2008 and showed the LOS is limited to 1,400-1,500 MW by PJM system constraints and to 1,600 MW by constraints in the NYISO. The critical PJM external limits are tied to the loss of Hydro Quebec to Sandy Pond at around 1,400 MW. Although the backbone improvements in PJM increase the West to East transfer limits within PJM, external limits remain constrained because economic dispatch is expected to load the PJM interfaces to their limit.

The JIPC evaluated several major transmission expansion reinforcement scenarios in New York and PJM and their impact on the Hydro Quebec-Sandy Pond contingency at 1,500 MW and 1,800 MW. The study considered a 230 kV replacement of the Plattsburgh-Vermont (PV-20) 115 kV transmission line and a second Pleasant Valley-Long Mountain 345 kV circuit. The study results showed the replacement of PV-20 115 kV transmission line with a Plattsburgh-230 kV tie with a PAR set at 330 MW would increase the Central East transfer capability by approximately 150 MW. The Hydro Quebec-Sandy Pond contingency

[7] The presentation on this subject is available at http://www.interiso.com/public/meeting/20071214/20071214_Feasibility_Loss_of_Source_Study.pdf.

at 1,800 MW showed acceptable system performance with a Central East transfer of 2,800 MW. The Plattsburgh-230 kV transmission reinforcement with a PAR set at 150 MW increased the Central East transfer capability by approximately 50 MW. For this scenario, the Hydro Quebec-Sandy Pond contingency at 1,800 MW was acceptable at a Central East transfer of 2,700 MW. Because the second Pleasant Valley–Long Mountain 345 kV tie appeared less promising, the JIPC decided to conduct more detailed studies of the North Country, Vermont, and a new upgrade interconnecting Plattsburgh and Vermont. (See Section 4.4 below.).

4.2 Interregional Impacts of PJM 500 kV Expansion Plan

PJM has added several EHV facilities to its Regional Transmission Expansion Plan (RTEP) that were included in the analysis conducted in the Northeast Coordinated System Plan. A project connecting the 502 Junction station in southwestern Pennsylvania with the Loudoun station in Virginia was added to the 2006 RTEP. Additionally, the PJM Board of Managers approved two additional EHV facilities in the 2007 RTEP. The Amos to Kemptown 765 kV line will tie the Amos station in West Virginia to a new station called Kemptown in northern Maryland. The line will interconnect the 765 kV system with existing 500 kV facilities at Kemptown as well as a midpoint station. The Susquehanna to Roseland line is a new 500 kV line that will interconnect the existing Susquehanna station in northeastern Pennsylvania with the Roseland station in northern New Jersey. Each of these projects was added to the RTEP primarily to resolve thermal and reactive issues that were identified through PJM's deliverability criteria. These lines significantly increase the west to east transfer capability across the PJM. Extensive analysis of the impact of these lines on the PJM system as well as adjacent systems has been completed. The results of this analysis are summarized in this section of the report.

4.2.1 Loss-of-Source Transfer Analysis

Power Voltage (PV) analysis is a common method to determine transfer capability across a region. This method measures the voltage at a given point in a system compared to a magnitude of a transfer across a region. A plot of the power transfer level versus voltage for a point on the system can be used to visualize the relative impact of multiple scenarios. This type of analysis was done on the PJM, NYISO and ISO-NE systems. Specifically, analysis of the impact of multiple NYISO and ISO-NE loss-of-source contingencies on the west to east transfer limit on the Juniata 500X interface in the PJM system was completed. A single stressed case was used as a base case for the PV analysis of multiple loss-of-source contingencies.

Starting with a base case, west-to-east transfers were applied to create a stressed case. Generation in the PJM's Western Region was the source of the transfers, and the transfer sink was PJM's Eastern Mid-Atlantic generation. Transfers were added to the case until the Juniata 500X interface, defined as the sum of flows on Conemaugh–Airydale 500 kV and Keystone–Airydale 500 kV, was loaded to its reactive limit (as defined by PJM operating criteria with respect to internal PJM contingencies). In this case, adding additional transfers to the case would cause a reactive violation on the Juniata 500X interface for the contingency loss of the Salem Unit 1 generator. No other contingencies resulted in reactive violations in the stressed case.

The case included the following scheduled projects and system conditions:

- Neptune project (PJM Queue G07_MTX) modeled at 685 MW exporting to LIPA according to its firm withdrawal rights
- PJM Queue G22_MTX modeled at 300 MW exporting to Con Ed according to its firm withdrawal rights

- Ramapo PARs pushing a total of 800 MW toward NY
- Airydale bus between Juniata and Conemaugh/Keystone with a 1,000 MVAR static capacitor
- Elroy 600 MVAR dynamic reactive device
- Branchburg 400 MVAR capacitor
- PSEG and NY wheel maintained at 1,000 MW
- TRAIL: 502 Junction–Mt Storm–MeadowBrook–Loudoun 500 kV circuit
- PATH: Amos 765 kV–Bedington 765 kV–Bedington 500 kV–Kemptown 500 kV
- Susquehanna–Lackawanna–Jefferson–Roseland 500 kV circuit

Analysis was then performed to determine the severity of NYISO and ISO-NE loss-of-source contingencies as compared to PJM internal contingencies. The analysis consisted of applying PJM operating criteria to the Juniata 500X interface, which involved creating "PV curves" by applying additional transfers to the stressed case. A PV curve is a plot of the voltage at a given location versus a measured amount of transfer across a region.

For each contingency, the analysis consisted of applying a transfer from source to sink followed by the application of the PJM voltage drop test to obtain post-contingency flows and voltages. Transfers were applied until reaching a point at which the post-contingency load flow solution attempt diverged.

The comprehensive PV analysis conducted for the conditions described above yielded the following results:

- The limiting buses in PJM were Juniata and Brighton
- The most limiting PJM contingency was the loss of Salem Unit 1
- Imports into Sandy Pond at 2,000 MW caused more severe PJM transfer limitations than PJM internal contingencies
- The contingency loss of Millstone 3 and Indian Point caused less severe limitations than the loss of Salem 1 or loss of Sandy Pond at 2,000 MW
- Maximum PJM West to East Transfer Capability was limited to 3,800 MW due to loss of Salem Unit
- Maximum PJM West to East Transfer Capability was limited to 2,700 MW due to loss of 2,000 MW at Sandy Pond. Maximum PJM West to East Transfer Capability was limited to 3,575 MW due to loss of 1,500 MW at Sandy Pond
- Backbone projects reflected in the PJM system have increased the West to East transfer capability by 2,000 MW

Based on these results of the system analysis, the loss of Sandy Pond at 1,400 MW to 1,500 MW has an equivalent impact as PJM's worst internal contingency when critical interfaces are at their limit. Although the PJM interface limits are significantly higher than previous assessments due to transmission improvements, the loading of those interfaces will likely be operated near their limits due to the economic transfer of power.

Stakeholders may wish to fund system impact studies in NYISO, PJM, or both systems that would consider the addition of reactive support in those systems and effectively increase voltage limits in constraining interfaces. This approach would provide stakeholders with Financial Transmission Rights in the NYISO and PJM systems that would serve as a hedge against times when the LOS limit may restrict transfers over the Phase II interconnection.

4.2.2 PJM Dynamic Analysis

In addition to the reactive analysis described above, a dynamic assessment of the combined ISO-NE, NYISO and PJM system was also completed on a 2013 system. The system was assessed by simulating a representative set of contingencies in PJM, ISO-NE and NYISO. Contingencies that were simulated as part of the 2004 NPCC Overall Transmission Reliability Study on a 2009 system were included in this assessment of a 2013 system. This included critical extreme contingencies in New England and key normal criteria contingencies in New York.

The stability analysis results indicate that the interconnected power system would be stable with satisfactory damping for the contingencies and system conditions that were tested. This analysis suggests that the planned backbone 500 kV and 765 kV improvements in PJM will result in acceptable system performance.

4.3 North Country (NY) Wind Operating Studies

NYISO, ISO-NE, NYPA, VELCO, NGrid and NYSEG are participating in the North Country Wind Study. The study will focus on the integration of the wind projects along the 230 kV Moses–Willis–Plattsburgh corridor, which are scheduled to be in service by the end of 2009. The study will examine four base case conditions; two of the four base cases have been completed, and the remaining two are under development. The study will also update the stability limits for the various outage conditions of the Moses–Willis–Plattsburgh lines. Results are scheduled to be completed the first quarter of 2009.

4.4 Plattsburgh Vermont Interconnection Upgrade

Previous studies presented to the IPSAC show that voltage limitations would restrict New York's Central East interface to about 2,800 MW. Pre-feasibility studies of replacing the 115kV tie between Plattsburgh and Vermont (PV-20) with a 230 kV tie showed that both the Central East limit and the New England LOS limit could be increased.

To build upon previous results, a pre-feasibility study has been completed that considers the addition of a 230 kV tie between Plattsburgh and Vermont but retains the existing Plattsburgh Vermont (PV-20) 115 kV interconnection. This new pre-feasibility study was motivated by six factors: 1) increased interconnection of wind projects in northern New York is producing transmission constraints out of the North Country; 2) Vermont is developing a new Ten-Year Electric Plan and seeks access to more renewable resources outside of the region, i.e. in New York and Canada; 3) the existing PV-20 tie has had a number of forced outages and an additional source to the area could prove beneficial; 4) New York's Central East interface can limit the transfer of power across the New York system; 5) previous New England LOS studies showed that potential increases in limits can be achieved with upgrades to PV-20; and 6) planning improvements to the PJM backbone transmission system.

Approximately 600 MW of wind development is in various stages of development in the North Country of New York. Resources in that area may become constrained without the addition of transmission improvements that provide higher transfer capability out of the area.

The most recent Vermont ten-year plan was completed in June 2006 for the year 2016. The next ten-year plan will be done in 2009. Critical assumptions in the plan are whether Vermont Yankee would be relicensed to continue operating beyond 2012, and whether the Highgate purchase, which ends in 2016, would be continued. The 2006 Plan includes adding a second causeway cable to PV-20 to reduce outage times to one day. The studies show this cable could be deferred if the Highgate purchase continues beyond 2016. However, because the critical outage would then be the Sandbar PAR, which could take from days to months for replacement, the continuation of the Highgate purchase would defer other transmission projects, but not the second PV-20 cable.

4.4.1 Upgrades Studied and Study Method

The pre-feasibility study of upgrade alternatives to PV-20 considered the following alternatives:

1. Build a new 230 kV transmission interconnection from Plattsburgh, NY, to New Haven, VT
2. Build a new 230 kV transmission interconnection from Plattsburgh, NY, to Granite, VT

These alternatives include two step-down transformers at Essex, Vermont, and a phase angle regulator at Sandbar, Vermont. Other alternatives will also be explored, including a 345 kV tie from Plattsburgh to New Haven and various combinations of transformers.

The base case for the study was set at 2008 estimates of 2013 load levels and reflected upgrades in New York, New England, and PJM. The base cases reflected a stressed New York Central East flow of 2,750 MW and transfers across other interfaces were within normal limits. Several key N-1 contingencies were analyzed and compared against loss-of-source contingency in New England.

4.4.2 Study Results

The study results to date suggest a new 230 kV interconnection improves system performance by increasing transfer limits across Central East and allowing higher permissible loss-of-source contingency limits in the New York and PJM interfaces. In addition, this alternative should be considered an option for meeting the long-term electric energy needs of Vermont, providing an additional outlet for wind generation in New York's North Country, and establishing a second tie between New York and Vermont that can support the system for a long-term outage of the existing PV-20 tie.

As the next step, a more comprehensive analysis of the two options already considered as well as the examination of additional options is being planned.

4.5 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 New England, NYISO, and PJM annually 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 annually.

All projects within an ISO/RTO are reviewed and where potential interregional impacts are recognized, the studies are coordinated with neighboring systems. The scope of work is developed to reflect common databases, base cases, contingencies, and other considerations.

Table 4-1 lists projects in the interconnection queues of ISO NE, NYISO and PJM that potentially have interregional impacts. These projects are in various stages of development and ISO/RTO approval processes. In a few cases, the projects may be close to going into service or are actually in operation.

Table 4–1
Interconnection Queue Projects with Potential Interregional Impacts

Queue No. or ID	Description	Summer Capacity MW	Location	Estimated Commercial Operation
		ISO New England Projects Affecting New York[1]		
190	Gas Turbine	39	Litchfield County, CT	1/31/2010
125	Norwalk Harbor Redevelopment	322	Fairfield County, CT	1/31/2010
175, 182	Gas Turbine	175	Fairfield County, CT	6/1/2010
267	Gas Turbine Alternative to 175/182	175	Fairfield County, CT	6/1/2010
271	Two terminal line, DC	N/A	Fairfield County, CT	3/31/2014
196	Pumped Storage Upgrade	1,180	Franklin County, MA	6/30/2010
227	Pumped Storage Upgrade	333	Berkshire County, MA	3/31/2011
227	Pumped Storage Upgrade	333	Berkshire County, MA	3/30/2012
277	Combined Cycle	695	Fairfield County, CT	6/1/2013
281	Wind	85	Rutland County, VT	9/1/2011
		New York Projects Affecting New England and PJM[b]		
125	Linden Variable Transformer	300	Staten Island, NY	Q4 2009
N/A	Neptune Project	685	Newbridge, LI	In Service
206	Bergen DC/AC Tie	660	W49 St, NYC	Q2 2011
Various	14 Generation Projects	11,592	Various	Various
Various	8 DC/AC Projects	6,850	Various	Various
Various	27 Wind Projects	2,954	Various	Various
		PJM Projects Affecting New York[c]		
G07_MTX	Neptune Project	685	Firm export to LIPA	In Service
G22_MTX	Linden Variable Transformer	300	Firm export to Con Ed	Q2 2009
066	DC Tie	670	PSE&G to Con Ed	TBD

(a) Based on ISO-NE's September 10, 2008, Queue and several more recent project additions

(b) Based on New York ISO's October 30, 2008, Queue. One project has 3 phases.

(c) Based on PJM's November, 2008, Queue

4.6 Multi-Regional Transfer Analysis

4.6.1 Analysis of Loop Flow Between New York and New England

This section summarizes the study work to determine any significant loop flows across the New York and New England interface. The NYISO and PJM conduct similar studies as needed but their transmission ties are mostly controlled by phase angle regulators (PARs) which can be operated to control or prevent loop flows.

In resource adequacy studies, a simplified system model is used that aggregates loads into zones commonly referred to as “bubbles”. The aggregation of load and resources into these zones is based on transfer limit studies that determine limitations on the flow of power in the transmission network among these zones. These zones are connected by interface ties at their boundaries. These ties are used in the resource adequacy simulation model to limit the permissible flow of power between these zones. However, this modeling representation does not account for any “loop flows” where generation shifts within one system result in substantial power flows across the neighboring system.

The focus of this study was to determine the potential for loop flow over the free-flowing ties between New England and New York. This interface has more potential for loop flow than the NY-PJM interface because of the PARs on that interface.

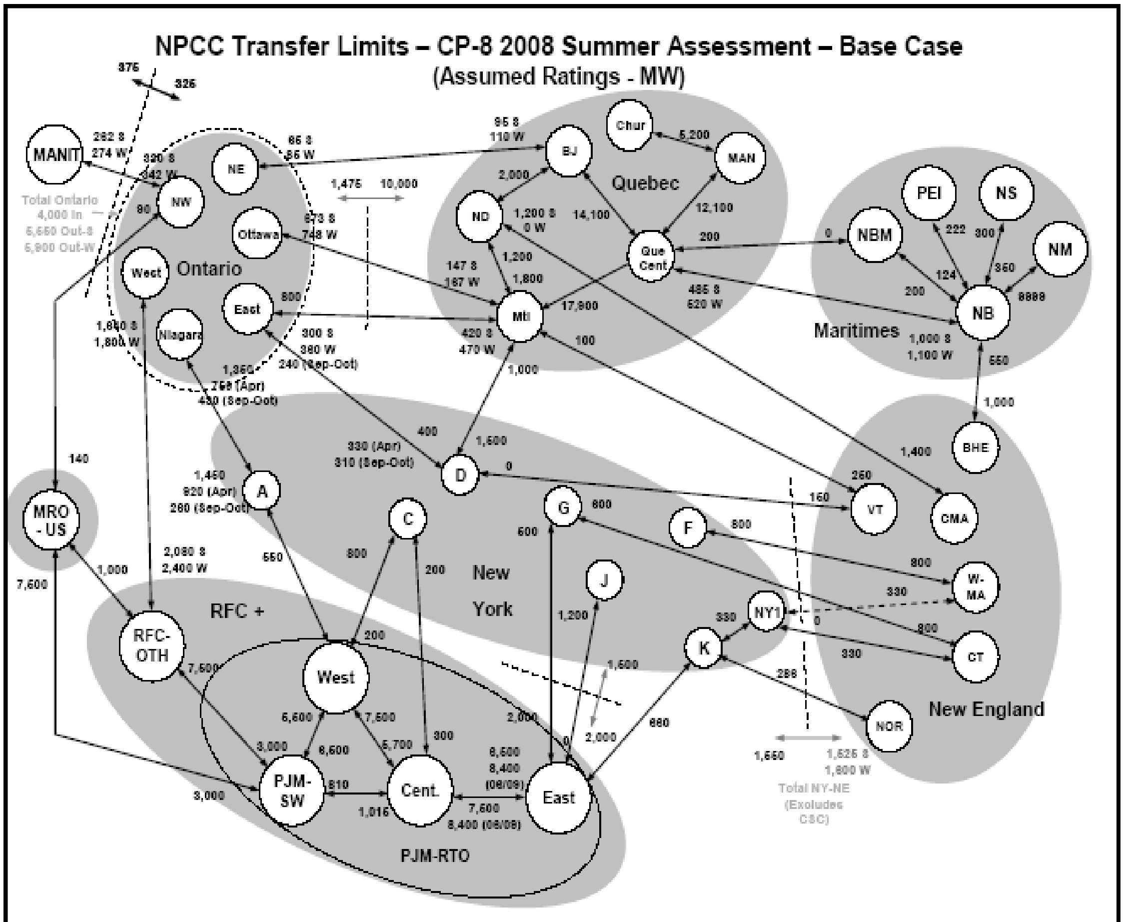

Figure 2 - Assumed Transfer Limits

Figure 4-1 Assumed Transfer Limits from NPCC 2008 CP-8 Summer Assessment

Figure 4-1 shows the topology of zones and interface limits presently utilized in interregional resource adequacy studies such as CP-8[8]. The objective of this NCSP loop flow analysis was to update this existing network topology and transfer limits to reflect any loop flow between New York and New England. The existing model only reflects the results of transfer limit studies performed individually by the respective regions. The existing resource adequacy transmission model for the New York and New England system is modeled with the following major load zones shown in Table 4-2.

[8] Additional information on CP-8 Seasonal Assessments can be found at http://www.npcc.org/documents/reports/Seasonal.aspx

Table 4-2 New York and New England Modeling Zones

New York	New England
Zone A	BHE
Zone B	BOS
Zone C	CMAN
Zone D	CT
Zone E	ME
Zone F	NH
Zone G	NOR
Zone H	RI
Zone I	SEMA
Zone J	SME
Zone K	SWCT
	VT
	WMA

The analysis was performed by shifting generation between selected zones and monitoring the transmission interfaces in New York and New England. These interfaces are listed below:

- New York UPNY–SENY
- New York Zone F to Zone G
- New York Dunwoodie South
- New York–New England North
- New York–New England South
- New England Southwest Connecticut
- New England Connecticut Import
- New England North South
- New England East West
- New England Scobie+394

Generation shift factors indicate the amount of power that will flow across an individual interface or circuit when power is transferred across a power system. For this analysis, generation shifts were made for various combinations of zones by increasing generation in one or more zones and lowering it in one or more other zones. The change in flow is expressed as a percentage of the total flow occurring from the generation shifts. The results of the analysis are shown in Table 4-3.

Table 4-3 – Generation Shift Impacts of Transfers on Transmission Interfaces

	Transfers												
Interface	ME-CT	ME-BOS	ME-SWCT	CMA-CT	CMA-BOS	CMA-SWCT	WMA-CT	Zone A-Zone E	Zone A thru Zone C – Zone J	Zone F – Zone J	Zone A thru Zone C – SWCT	Zone A thru Zone C – NEPOOL	ME-Zone J
UPNY-SE NY-OP	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	0%	0%	100%
F-G	14%	14%	20%	13%	0%	19%	10%	-1%	57%	70%	40%	21%	38%
Dunwoodle South	0%	0%	0%	0%	0%	0%	0%	0%	100%	100%	0%	0%	100%
NE-NY-N	17%	2%	25%	16%	1%	24%	13%	1%	-8%	-12%	-35%	-56%	51%
NE-NY-S	-17%	-2%	-25%	-16%	-1%	-24%	-13%	-1%	8%	12%	-66%	-43%	49%
SWCT	5%	1%	64%	5%	0%	63%	4%	0%	-3%	-4%	78%	16%	-17%
CT Import	100%	0%	100%	100%	0%	100%	100%	0%	0%	0%	100%	13%	0%
North South	98%	98%	98%	1%	0%	1%	1%	0%	0%	0%	0%	-50%	98%
East West	97%	2%	96%	95%	0%	95%	93%	0%	1%	1%	2%	-36%	95%
Scoble+394	89%	89%	88%	0%	23%	0%	0%	0%	0%	0%	0%	-6%	88%

Table 4-3 indicates that the potential for loop flow between New England and New York occurs across the northern part of the New England–New York interface (Berkshire–Alps 345 kV, Bear Swamp–Rotterdam 230 kV, Whitehall–Blissville 115 kV, Bennington–Hoosick 115 kV, and Grand Island–Plattsburgh 115 kV) and the southern portion of the New England–New York interface (Southington–Pleasant Valley 345 kV, Norwalk–Northport 138 kV, and Salisbury–Smithfield 69 kV). For transfers remote to the New England–New York interface (ME–BOS, CMA–BOS, and A–E), the amount of loop flow would be less than two percent. The amount of loop flow increases as transfers are scheduled across zones, which parallel the New England–New York interface such as ME–SWCT, CMA–SWCT, or Zones A through Zones C to J. However, the directions of the large loop flows are in opposite directions and would tend to cancel each other out, when viewed across the entire interface.

This loop flow analysis confirms that the net total loop flow is very small across the interface between these two Control Areas. The results show that resource output variations located close to the interface within the Hudson River Valley of New York have measurable impacts on interface circuits into and within western New England and vice versa. However, the current bubble or zonal modeling representation for multi-Area resource adequacy studies is still sufficient for engineering analysis. This is because the transportation limits used are sufficiently constraining to account for the localized occurrences of loop flow. The results also show that loop flow is a factor that must be considered in transmission analysis, transmission planning studies, and the establishment of interface limits.

4.7 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.

5. Additional Coordinated Planning Activities and Issues

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 now discussed.

5.1 Northeast Power Coordinating Council

The Northeast Power Coordinating Council 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's geographic area is northeastern North America and includes New York, the six New England states, Ontario, Québec, and the Maritime Provinces in Canada.[9] Pursuant to separate agreements with its membership and NERC and by a Memorandum of Understanding with the applicable Canadian authorities, the NPCC provides the following activities and services to its geographic area:

- Statutory activities—develop regional reliability standards, assess compliance with and enforce these standards, coordinate system planning, design, and operation, and assess reliability
- Non-statutory criteria services—establish regionally specific criteria and monitor and enforce compliance with these criteria

ISO New England and NYISO are committed to the goals and methods of the NPCC and to plan and operate their systems in full compliance with NPCC criteria, standards, guidelines, and procedures. They are also active participants in NPCC interregional studies and planning initiatives with the full technical participation by PJM.

5.1.1 Coordinated Planning

The 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. The 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 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 *Guidelines for Area Review of Resource Adequacy* (Document B-08) on the basis of the schedule set forth in the NPCC Reliability Assessment Program.[10] The TFCP also reviews the compliance of future plans with the basic criteria consistent with the *Guidelines for NPCC Area Transmission Reviews* (Document B-4).[11] All studies are well-coordinated across neighboring area

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

[10] Guidelines for Area Review of Resource Adequacy, NPCC Document B-08 (New York, NPCC Inc., November 29, 2005); http://www.npcc.org/documents/regStandards/Guide.aspx

[11] Guidelines for NPCC Area Transmission Reviews, NPCC Document B-04 (New York, NPCC Inc., March 5, 2008); http://www.npcc.org/documents/regStandards/Guide.aspx

boundaries and include the development of common databases that can serve as the basis for internal studies by each ISO.

In coordination with NERC, the NPCC also gathers data and assesses the resource adequacy of its five areas.[12] The results of these studies show that 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 areas during the peaks. The seasonal diversity also changes the overall summer and winter system flows of electric power and energy.

5.1.2 Resource Adequacy Analysis (CP-8)

Under the CP-8 Working Group, NPCC coordinates resource adequacy studies of its ISO/RTO Areas and provides technical support that is necessary for the determination of tie benefits. NPCC will be undertaking a summer 2009 multi-area probabilistic reliability assessment of the NPCC region and other neighboring systems, including PJM. The study will determine the loss-of-load expectation (LOLE) of that interconnected system for the period May through September of 2009. It will use the GE MARS program evaluating a base case and a severe case for this period and will be completed by April 2009. The modeling of transmission limits used in this study will incorporate the multi-regional analysis referenced in Section 4.6.

5.1.3 NPCC Overall Transmission Assessment

In accordance with the NPCC Reliability Assessment Program, the Task Force on System Studies (TFSS) is mandated to perform an Overall Transmission Assessment (OTA) of the reliability of the planned NPCC bulk power system every three years. This study will assess the performance of the NPCC system by evaluating the dynamic and steady state performance of the entire NPCC system for various design and extreme contingencies under conditions projected for 2013. The study builds upon and supplements the Transmission Reviews conducted annually by each of the NPCC Areas by examining the system from a broader regional and inter-regional perspective.

The OTA study will also include an evaluation of the impact of proposed large future system developments in the adjacent Reliability*First* Corporation (RFC) region and determine the effect of extreme contingencies in the RFC region and potential power swings arising from disturbances outside the NPCC's interconnected systems. Simultaneous transfer limit studies will be conducted to determine the limits for key interfaces at and near the border of the RFC and New York Control Area (NYCA) systems. The interfaces will be tested in a manner similar to the load/generator deliverability testing procedures of each ISO/RTO.

NPCC is scheduled to kick off the Overall Transmission Assessment later this year. The study will examine the NPCC system from a broad inter-regional perspective by including the impact of planned 500 kV and 765 kV facilities proposed within PJM. The study will assess how these facilities affect critical contingencies on the NPCC systems, parallel flows and congestion throughout the Ontario and New York systems. Participation of adjacent regions in the NPCC study is expected. Scheduled for completion in 2009, the OTA study builds upon and is coordinated with other ISO/RTO studies.

[12] The NERC Reliability Assessment Subcommittee (RAS) publishes several reports; see http://www.nerc.com/page.php?cid=4|61.

5.1.4 NPCC Transmission Reviews

Studies conducted by each of the areas complement and are consistent with the Overall Transmission Assessment. The NPCC Comprehensive Area Review (CAR) testing is done typically every five years. Currently it is being done for a 2013 case that includes all changes to existing and planned projects through 2013. The testing includes load flows for all normal and extreme contingencies, and review of dynamic control systems, dynamic VARs and special protection systems. The Task Force on System Studies (TFSS) provides the guidance and oversight for these reviews. Each area of NPCC does the testing of its system and the interconnections with adjacent areas and reports to the TFSS.

The most recent CAR reviews for New England and New York were done in 2005 for the year 2009 and two interim reviews were since conducted by each of the regions. These studies document the changes in load forecasts, generation and transmission facilities since the last review, and the CAR review concludes that internal studies show that the additions to the bulk power system planned for 2012 are in conformance with NPCC Basic Criteria for Design and Operation of the Interconnected Power System.

Sensitivity studies will be conducted to determine the impact of proposed major 500 and 765 kV facilities in the adjacent RFC region, and how these facilities may impact NPCC systems including critical contingencies, parallel path flows and shift in distribution factors through both Ontario and New York.[13]

5.1.5 RFC 2013 Summer Long-Term Reliability Study

The Reliability*First* Transmission Performance Subcommittee (TPS) and the Reliability*First* staff have assessed the Reliability*First* Bulk Electric System pursuant to the requirements of North American Electric Reliability Corporation (NERC). The purpose of this study was to assess vulnerabilities of the Bulk Electric System in Reliability*First* to widespread cascading outages. Existing manual operating procedures or remedial actions that address the system conditions that may otherwise cause cascading outages were reviewed. The study results can be used by the study participants as one of the inputs to evaluate the need for (1) system improvements; (2) new operating procedures or remedial actions; and (3) automation of existing operating procedures or remedial actions. The assessment fulfills the requirements in NERC Reliability Standard TPL-005 and the Electric Reliability Organization (ERO) Rules of Procedure under Section 800 to conduct a long-term transmission assessment and provide a broad picture of the expected performance of the Reliability*First* system with emphasis on identifying potential transmission constraints. The Reliability*First* 2013 Summer Long-Term Assessment of Transmission System Performance is divided into two reports. This public report is the first of two and contains an overview of the assessment, basic study design, observations regarding the Reliability*First* transmission system, and conclusions drawn from study results. The reader seeking greater technical detail regarding the study procedure as well as complete documentation of all results is referred to the separate technical report, which contains CEII protected information and is not available to the general public.

The 2013 base case was developed using the 2007 Series ERAG MMWG 2013 summer model of the eastern interconnection system including NPCC.[14] Both N-1 (single) and N-2 (double) contingencies were studied, without simulation of operator intervention. These contingencies were studied in the base case and in four transfer scenario cases. Over 1.4 million N-2 contingencies were screened in five power flow scenarios for either loadings in excess of 110% of transmission line emergency ratings, 130% of transformer emergency ratings, or low voltages at generator terminals. Generally, these N-2 contingencies

[13] The NPCC transmission reports are available on the NPCC Member web site at: https://www.npcc.org/documents/reviews/Transmission.aspx.

[14] Series ERAG MMWG is short for the Eastern Interconnection Reliability Assessment Group's Multiregional Modeling Working Group model, an annually released power flow containing system conditions for the entire eastern interconnection.

consisted of either two transmission lines with one operating at 230 kV or above and the second operating at 345 kV or above; or one generator and one transmission line/transformer with the generator producing 300 MW or more and the transmission line operating at 345 kV or above. The transfer scenarios included the Midwest Reliability Organization (MRO) to Southeast Reliability Corporation (SERC) sub-regions, Central to Virginia–Carolinas (VACAR) (NW to SE), both Central and VACAR to MRO (SE to NW), Southwest Power Pool (SPP) and SERC Sub-regions Gateway and Delta to NPCC (SW to NE) and NPCC to SPP and SERC Sub-regions Gateway and Delta (NE to SW). The results of this study are posted on the Reliability*First* web site[15].

5.2 IRC Activities

Created in April 2003, the ISO/RTO Council is an industry group consisting of the ten 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. With the implementation of Order No. 890, ISOs/RTOs are upgrading their planning processes to meet the FERC's nine planning principles[16]. 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 that is driven efficiently by competition and that meets all reliability requirements.

A principal function of the IRC is to coordinate policies on issues of common interest across geographical boundaries. This is shown by joint and coordinated ISO/RTO filings with FERC on many issues, such as those concerning the administration of the ISOs' Generation Interconnection Queues, the development of procedures and standards for Electric Reliability Organizations (ERO) and other market and operational issues. For example, the integration of wind resources presents many planning and operating challenges. The IRC Wind Study Task Force is examining market design and reliability issues and, through its representatives, is leveraging the efforts of NERC's Integrating Variable Generation Task Force (IVGTF). The IVGTF's assignment is described in more detail in Section 6.3.2.

In April 2008, the IRC convened a technical conference on measurement and verification standards ("M&V") for demand response and the development of communications protocols to facilitate the integration of small DR resources. The IRC Markets Committee led the collaborative efforts, which have

---

[15] Reliability*First* website: http://www.rfirst.org/Reliability/ReliabilityHome.aspx.

[16] *Preventing Undue Discrimination and Preference in Transmission Service, Final Rule*, 18 CFR Parts 35 and 37, Order No. 890 (Docket Nos. RM05-17-000 and RM05-25-000) (Washington, DC: FERC, February 16, 2007); http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf . Also see *Open Access Transmission Tariff Reform, Order No. 890 Final Rule* (Washington, DC: FERC, 2007); http://www.ferc.gov/industries/electric/indus-act/oatt-reform/sum-compl-filing.asp . While not FERC jurisdictional, the Canadian ISO/RTO processes are intended to comply with Order 890 requirements.

resulted in the development of M&V standards for demand response through the North American Energy Standards Board.[17]

5.3 Eastern Interconnection Reliability Assessment Group

In 2006, the six Managers of the NERC regional entities within the Eastern Interconnection developed and executed an agreement that governs the interregional assessment studies in the Eastern Interconnection. The purpose of the Eastern Interconnection Reliability Assessment Group (ERAG) Agreement is to further augment the reliability of the bulk-power system in the joint areas through periodic reviews of generation and transmission expansion programs and forecasted system conditions.

There are three ERAG study forums—RFC-NPCC, RFC-SERC East and RFC-MRO-SPP-SERC West. The present RFC-NPCC Steering Committee and Working Group are direct descendants of the MAAC-ECAR-NPCC (MEN) Study Committee and Working Group. The present RFC-SERC East Steering Committee and Working Group are direct descendants of the VACAR-RECAR-MAAC (VEM) Study Committee and Working Group. The ERAG Management Committee is essentially an offshoot of the Joint Interregional Review Committee (JIRC) but the extent of responsibility was expanded to the entire Eastern Interconnection. In addition, ERAG took over all previous NERC steady state and dynamic base case development responsibilities for the Multi-Regional Modeling Working Group in 2006. That effort has expanded from previous responsibilities to include development of additional base cases, base case benchmarking, and disturbance analysis models.

5.3.1 Future Assessment Need

The ERAG Management Committee has recognized the need for assessment of the future condition of the interregional system. A survey was conducted of NPCC, RFC, PJM, MISO and SERC to determine what seasonal and future assessments have been conducted and the extent of their interregional coverage. The results of the survey have been reviewed to consider impacts of anticipated large future system developments (e.g. large wind resource additions, TRAIL 500 kV line and PATH 765 kV lines, New York developments, Ontario generation additions and retirements, etc.). These facilities and other major projects will be included in future assessments (e.g. NPCC Triennial/Overall Transmission Reviews, PJM Assessments and RFC assessments). NERC standard requirements for seasonal and future assessments have also been reviewed.

The ERAG Management Committee is considering staffing and budget needs to conduct interregional future assessments during 2009. That would be done through separate future assessments in each study forum. A first proposal has been made to forgo the 2009/2010 winter assessments and focus on getting a future assessment done over the whole year, with completion of a summer 2009 assessment still required during the spring. That would include steady state transfer capability assessment, assessment of any proposed SPSs, etc. Commitments for staffing to do this and concerns with this approach are being reviewed.

5.4 Summary

Interregional studies are increasing in importance and the need for coordinated studies of the planned future systems cannot be overemphasized. NPCC continues to promote and participate fully in proposed joint studies with its neighboring regional reliability council, Reliability*First* Corp. (RFC). These studies intend to 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

[17] North American Energy Standards Board; http://www.naesb.org/.

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. The three ISO/RTOs will continue participation in these forums to ensure a reliable and efficient bulk electric system in upcoming years.

6. Wind and Renewable Resource Studies

This section covers studies related to the development of large wind and renewable resources. The integration of these resources presents operational challenges to each ISOI/RTO. The JIPC is a venue through which ISO-NE, NYISO, and PJM communicate planning efforts. In order to both avoid duplication of work and to expedite solutions to this pressing issue, the ISO/RTOs are participating in several group efforts related to wind integration. The following section outlines some of the major study groups investigating wind issues at an interregional level.

6.1 Joint Coordinated System Plan Study (JCSP)

The potential for hundreds of thousands of megawatts of wind capacity development in the American Midwest exists. As a result, the 2008 Joint Coordinated System Plan conducted a scenario analysis with the following goals:

- Develop power flow and production cost models to perform studies of nearly the entire Eastern Interconnection
- Perform a transmission reliability assessment study to anticipate potential regional issues in 2018
- Perform a study to identify the possible need for conceptual transmission upgrades based on the dual assumption that, by 2024, (1) wind energy resources supply 20% of the electric energy for the majority of the U.S. portion of the Eastern Interconnection, and (2) most of the wind development is in the Midwest with few new economical sources of energy located in the Northeast
- Incorporate the objectives of DOE's Eastern Wind Integration and Transmission Study into the JCSP scenario analysis and provide technical support for the DOE study.[18] The DOE goals include identifying the benefits of conceptual long-distance transmission to access remote wind resources and to facilitate the management of wind variability and uncertainty over a wide footprint

Through open forums, stakeholders have discussed the assumptions and draft results of the JCSP analysis. For the wind expansion scenarios, the JCSP developed major conceptual transmission "overlays" that would link the resources in the Midwest to the major load centers along the East Coast. The initial effort under the JCSP was completed in the first quarter 2009. The report and supporting materials are posted on the JCSP website: http://www.jcspstudy.org/.

The most recent results of the JCSP study were shared at the workshops held October 2, 2008, in Carmel, Indiana, and December 10, 2008, in Dallas, Texas. A primary focus of the JCSP analyses is the 2024 wind expansion scenario assumptions and simulation results. The Reference case assumes that wind resources supply 5% of the energy to the Eastern Interconnection. This scenario was chosen because 26 state/DC RPSs as of January 1, 2008, equate in aggregate to an effective 5% RPS for the Eastern Interconnection. Most of states in the upper Midwest, Great Lakes states, Mid-Atlantic, and Northeast have RPS in place. Since the models were created, Michigan and Ohio have implemented RPSs and other states are increasing or developing new RPSs.

[18] Synchronized wind models over a wide area are being developed under contract to the National Renewable Energy Laboratory within DOE. Additional information is available online at http://www.nrel.gov/wind/systemsintegration/.

The other scenario being studied by the JCSP is a 20% wind scenario. This scenario assumes incremental wind development would emphasize the central US plains and would provide 20% of the energy in much of the entire Eastern Interconnection. Results of these scenario studies will help demonstrate that integrating significant renewable resources could require potentially major EHV and HVDC expansion overlays to move power from the Midwest to load centers on the Eastern seaboard. According to MISO, initial estimates for the transmission expansion to support the reference (5%) and 20% wind scenarios would cost a minimum of $50 billion and $80 billion, respectively.

Several stakeholders have suggested the transmission costs could be at least three to five times as large. Another concern is that the 5% and 20% "wind scenarios" assumed the addition of over 76,000 MW and 35,000 MW of coal units primarily in the Midwest, without any retirements of coal-fired generation and no costs associated with carbon emissions. Finally, the need to consider a wide variety of additional scenarios, including additional use of smart grid and related metering and other energy efficiency technologies, development of localized renewables including offshore wind, and imports from Canada, has been identified and requires consideration prior to making any decisions regarding a final plan. While NYISO and ISO New England remain committed to participation in interregional studies of the Eastern Interconnection, NYISO and ISO New England did not sign the JCSP study report and have concerns with viewing the scenario transmission development as a "plan".[19] PJM also recognizes the need for conducting further analysis prior to considering any JCSP plan final.

Additional JCSP analyses of the 2024 conceptual transmission expansion plans are underway and the 2018 reliability assessment was completed in February, 2009. To date, the reliability study of a conceptual loop in 2018 linking the 765 kV system in the west to the 500 kV system in the east was shown to mitigate system issues identified by the assessment of the 2018 system. As a result, PJM has initiated a study effort with MISO that will further investigate the need for EHV improvements. The scopes of work for the next JCSP set of economic and reliability studies are under development.

6.2 Imports from Eastern Canada

The eastern Canadian premiers and Canadian utilities have a strategy to build over 13,000 MW of non-emitting hydro, wind, and nuclear-powered resources and intend to sell any excess power to Ontario and New England, typically outside eastern Canada's winter-peaking season.

Taking into consideration the seasonal load diversity previously referenced, some of the Canadian provinces also would expect to purchase power from the northeastern United States during their winter-peaking season. This is consistent with the goals of the Northeast International Committee on Energy (NICE), which has sought to reduce the overall emissions of greenhouse gases in the region and eastern Canada and to facilitate increased transfers of electrical energy between New England and the eastern Canadian provinces.[20] This plan also would diversify electric energy supplies for New England, provide additional sources of renewable energy, and potentially reduce costs to New England electric energy customers.

[19] For more details on this decision, see http://www.iso-ne.com/pubs/pubcomm/corr/2009/2009-2-4_jcsp.pdf

[20] NICE includes representatives from the New England Governors and the Eastern Canadian Premiers (NEG/ECP). Additional information about NICE is available online as follows: 1) the NEG Conference Inc. Web site, "New England Governors' Conference Programs, NEGC Energy Programs," http://www.negc.org/energy.html; and 2) NEG/ECP Resolution 31-1 of the 31st Conference of New England Governors and Eastern Canadian Premiers, Resolution Concerning Energy and the Environment (Brudenell, Prince Edward Island: NEG/ECP, June 26, 2007),http://www.negc.org/documents/NEG-ECP_31-1.pdf.

The overall strategy of increased transfers between New England and Canada requires the coordination of the respective transmission expansion plans in the Atlantic Provinces, Québec, and New England. The NICE currently is reviewing these transmission expansion plans and renewable resource development plans across the entire region to identify synergies between these system developments on either side of the international border. For all projects that could have an interregional impact, ISO New England also will closely coordinate with all neighboring systems to study and implement these projects and ensure reliable system performance among the balancing authority areas.

ISO New England has initiated Economic Studies that examine the impacts of adding new resources in various amounts and system locations. The almost 300 scenarios also account for various levels of load and relief of transmission constraints. Results of these studies are expected by the 2nd Quarter of 2009 and include scenarios that increase imports from Canada.

System improvements and interconnections, such as the Northeast Reliability Interconnect, require joint studies with neighboring systems. Additionally, through the Northeastern ISO/RTO Planning Coordination Protocol, the ISO/RTOs have remained alert to opportunities for jointly planning facilities with neighboring areas. These facilities could include additional tie lines to New York or to other balancing authority areas further west, that provide alternative sources of renewable energy and improve the overall reliability of the system.

6.3 DOE and NERC Wind Integration Activities

This section describes the DOE and NERC wind integration activities.

6.3.1 Eastern Wind Integration and Transmission Study

The Eastern Wind Integration and Transmission Study (EWITS) is being funded by the Department of Energy's National Renewable Energy Lab (NREL). This Eastern Wind Integration and Transmission Study will coincide with transmission analysis being conducted independently by several regional grid operators including the PJM, MISO, SPP, TVA, NYISO, ISO-NE, and other related entities. Because the transmission improvements assumed in the DOE analysis are based on the JCSP study discussed in Section 6.1, ISO New England has withdrawn from the EWITS study.

EWITS will focus on the integration of wind power into the Eastern Interconnection, a wide region covering much of the area of the eastern half of the U.S. The Eastern Mesoscale Study, a precursor to this study, will result in the identification of over 600 gigawatts (GWs) of potential future wind plant sites for the Eastern U.S., and this hourly time series data will be used as an input in the EWITS.

The work will consist of seven tasks:

1. Conduct preliminary analysis to develop scenarios that will examine high levels of wind penetration and answer specific stakeholder and Technical Review Committee (TRC) issues
2. Model a baseline assessment for the wind integration study area footprint without new wind
3. Conduct detailed transmission planning analysis for the entire Eastern Interconnection for the 20% and 30% wind energy scenarios
4. Model two high renewable scenarios based on a 20% and 30% wind energy penetration in the study footprint. Analyze wind integration within the study area footprint
5. Model two variations based on the 20% wind and/or the 30% wind energy penetration scenario analyzing wind integration within the wind integration study area footprint

6. Conduct effective load-carrying capacity (ELCC) and loss-of-load probability (LOLP) analysis on four high penetration wind scenarios within the wind integration study area footprint and
7. Prepare final reports

The work began in late summer 2008 and a final report is expected by the end of the third quarter of 2009.

6.3.2 NERC's Integration of Variable Generation Task Force (IVGTF)

In December 2008, in anticipation of the growth of wind and other variable generation, NERC's Planning and Operating Committees created the IVGTF and charged it with preparing a report to include both philosophical and technical considerations for integrating variable resources into the Eastern Interconnection, and specific recommendations for practices and requirements, including reliability standards that cover the planning, operations planning, and real-time operating timeframes.

The goals of this report will be to:

1. Raise industry awareness and the understanding of characteristics of variable generation
2. Raise industry awareness and the understanding of the challenges associated with large-scale integration of variable generation
3. Investigate the impacts on traditional approaches used by system planners and operators to plan, design and operate the power system
4. Scan NERC Standards, FERC rules and business practices to identify possible gaps and future requirements to ensure bulk power system reliability in light of large-scale integration of variable resources

The IVGTF has identified six planning reliability issues, three operating reliability issues and five variable generation technology reliability issues. The Planning and Operating Committees approved these issues along with specific actions at the September meeting. At present, a draft report is under NERC Operating Committee and Planning Committee review with comments due by the end of January 2009. Plans call for incorporating comments by interested parties by the end of February and issuing an approved report by March 2009. The IVGTF will then initiate the second phase of its study with separate operating and planning subgroups.

6.4 Wind Development and Integration Issues in New York, New England and PJM

This section presents the current status of wind development in the three ISO/RTOs and discusses the common issues among them on wind integration. While much work has been done to address the integration of wind projects into the systems by the three ISO/RTOs, this work is ongoing as the number of new wind resources continues to grow. The current issues being addressed are assuring adequate transmission development for integrating wind, wind forecasting, automatic generation control, reserve and contingency requirements, low-voltage ride-through, power factor, and other issues. As wind grows on these systems, these issues will become more and more important for system reliability. Since these issues are common to all three ISO/RTOs, they are discussed generically in Section 6.4.4.

6.4.1 New York

The NYISO currently has approximately 1,275 MW of wind plant in operation and another 300 MW should be in service by the summer of 2009. In addition, NYISO has close to 8,000 MW at various stages of development in its interconnection queue, including approximately 1,200 MW of off-shore wind. In

2004, the NYISO studied the impact of up to 3,300 MW of potential wind generation with the final report released in early 2005.[21] The potential is now much greater. NYISO has initiated several actions in response to this increased potential:

- Implemented a performance tracking system for existing wind plants
- Implemented a centralized forecasting process for wind plant output
- Developed, in conjunction with stakeholders a wind energy management proposal that will integrate wind into NYISO's market-based dispatch system in the summer of 2009
- Updating the original study for wind generation potential by studying installed wind plants ranging from 3,500 to 8,000 MW
- Participating in regional and national wind study initiatives

The primary focus of these actions is to concentrate on several issues that have been identified as important to successfully integrating much higher penetrations of wind generation. They are: 1) transmission; 2) system flexibility; 3) operator awareness and practices; and 4) wind generator plant performance and standards. These issues are discussed in Section 6.4.4. The updated NYISO study is scheduled for completion in the first quarter of 2009.

6.4.2 New England

ISO-NE is experiencing considerable growth in wind generation. Currently, there is more than 4,000 MW of wind plant in the interconnection queue with more than 813 MW having completed the approval for interconnection (known as the "I.3.9 process"). More than 450 MW of the wind generation with Planning Proposal Applications[22] are offshore. The first two wind plants of significant size within the ISO-NE service area will be in commercial operation by the end of 2008 or the beginning of 2009. These two wind plants have a combined nameplate capacity of slightly more than 80 MW.

To integrate wind projects, ISO-NE has developed a checklist of interconnection activities for wind generation and holds regular integration meetings with the wind generators to facilitate their integration into ISO-NE's real-time and market operations. Under a New England Economic Study Process Stakeholder Group, ISO-NE planning staff has been conducting economic analyses to see the potential market efficiencies from interconnecting large areas with wind resources both with New England, and through importing, wind and other renewables from Canada. In addition, ISO-NE has developed a qualification process for wind generators so that they may participate in the Forward Capacity Market.

Given the anticipated growth of wind generation in New England, ISO-NE will conduct a study, similar to NYISO, to be completed by the end of 2009. The goals of the study are 1) to build on previous wind studies; 2) to identify and address operational and market impacts for New England of wind generation in the queue and potential large-scale development of wind generation (including development in neighboring balancing areas); 3) to develop detailed technical interconnection requirements; 4) to determine wind generation's effective capacity contribution; and 5) to investigate and make recommendations for implementation of mitigation or facilitation measures to accommodate wind variability.

[21] The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations http://www.nyserda.org/publications/wind_integration_report.pdf.

[22] A PPA has final I.3.9 planning design approval.

6.4.3 PJM

PJM currently has approximately 1,800 MW of wind generation connected to the system with over 1,800 MW under construction. PJM has seen a significant increase in the number of interconnection requests for wind projects and the current PJM interconnection queue has approximately two hundred and fifty requests for interconnecting wind generation to PJM, corresponding to over 46,000 MW of new wind generation. This is roughly one-third of all the generation in the PJM queue. Most of these wind projects are clustered in Pennsylvania and West Virginia along the Appalachian Mountains and in Illinois. PJM assigns a 13% capacity value to wind as a class of resources, unless a higher value can be justified by a project.

6.4.4 Generic Wind Integration Issues

The generic issues for wind integration are 1) transmission interconnection; 2) system flexibility; 3) operator awareness and practices; and 4) wind generation performance and standards.

Transmission: Wind resources tend to be concentrated in areas of the power system, which historically had limited transmission capability. Expanding transmission will be a critical step in achieving the large-scale integration of wind. A significant amount of new transmission and/or enhanced utilization of existing transmission capability will be needed over the next several years to accommodate and integrate higher levels of wind generation into the interregional power system.

System Flexibility: The bulk power system will require increased ramping capability and resources that can be dispatched quickly to accommodate the increased variability and uncertainty of generation such as wind. Resource planning must ensure that the bulk power system has the quantity of flexible supply and demand resources necessary to accommodate the increase in variable generation– e.g., storage capability or off-peak load such as plug-in hybrid electric vehicles. Markets, pricing regimes and minimum standards should be developed to provide signals about the system characteristics that are most valued for both existing generators and for developers and entities that are planning new generation.

Operator Awareness and Practices: Enhancements are required to existing operator practices, techniques and decision support tools to increase the operator awareness of new variable generation and to operate future bulk power systems with large-scale penetration of wind generation. Wind generation must be visible to, and controllable by, the system operator, similar to any other power plant so the system operator can maintain reliability. For instance, the NYISO requires existing wind plants to be visible to system operations and is utilizing a short-term centralized wind forecast system for real-time operation to more accurately predict the magnitude and phase (i.e. timing) of wind generation plant output. In addition, based on its existing experience with operating wind plants, the NYISO has proposed to its market participants that wind plants participate in the NYISO economic dispatch/congestion management system in order to fully optimize the economics of the wind plants while maintaining reliability.

Wind Generation Plant Performance and Standards: Interconnection and generating plant standards need to be enhanced to ensure that variable generation’s design and performance contribute to reliable operation of the power system. These include the need to standardize basic requirements, such as:

- Power factor range (and thus reactive power capability)
- Voltage regulation
- Fault-ride through (low voltage and high voltage)
- Inertial-response (the effective inertia of the generation as seen from the grid is often zero)

- The ability to control the MW ramp rates on wind turbines and/or curtail MW output
- The ability to participate in primary frequency control (governor action, automatic generation control, etc.)

In addition, improved wind plant models need to be developed, validated and standardized for all wind technologies, especially for use in conducting stability and transient analysis studies.

Appliance controllers and automated technologies that modify load characteristics, known as “smart-grid” technologies, can mitigate stress on the grid and prevent power outages during grid emergencies. Smart-grid technologies also can help integrate renewable energy resources into the grid and may reduce the need to build generation, transmission, and distribution systems. Technologies can provide ancillary services, and possibly storage, both of which would facilitate the integration of wind resources. However, further research and development work is necessary.

6.4.5 Summary

Development of wind resources presents technical challenges for its successful integration. The JIPC is coordinating the solution to these challenges among the three ISO/RTOs, and the IPSAC is the vehicle to bring these issues to the attention of the stakeholders in the Northeast region.

7. Key Environmental Issues with Potential Interregional Impacts

Legislation and regulations dealing with key environmental issues have the potential to impact future interregional reliability. These would affect principally fossil fuel-fired electricity generators for air issues and fossil and nuclear generators for water issues. While there are many issues including acid rain (SO_2 and NO_X), ozone (NO_X), regional haze, mercury, particulates, CO_2 and cooling water impacts, only regulations intended to reduce ozone, CO_2 and cooling water impacts are discussed here and their potential to affect reliability across the three ISO/RTOs. These and other environmental factors could drive the interregional need to share capacity resources and build interregional transmission projects that can support the reliable and economic performance of the overall system.

7.1 Ozone Attainment

Major regions in the Northeast states served by the three ISO/RTOs are not in attainment of the new 2008 National Ambient Air Quality Standards (NAAQS) ozone 8-hour standard of 0.075 parts per million (ppm). While this new, tighter standard is expected to increase the number of areas with nonattainment designations for ozone, EPA is not expected to finalize the attainment status of the various localities until March 2010. States will then have three years (to March 2013) to develop and submit to EPA their state implementation plans for reducing ozone concentrations. Deadlines to attain the new standard will vary from 2013 to 2030, depending on an area's specific nonattainment classification. Meeting this new ozone standard is a major challenge for the NYISO, ISO-NE, and PJM and the fossil fuel power plants in the region. Figure 7-1 shows the areas nationwide that would not be in attainment of the new ozone standard based on 2004 to 2006 air quality data.

NO_X, which is emitted from fossil fuel power plants, along with Volatile Organic Compounds (VOCs) emitted largely by mobile sources, are the precursors to forming ozone on hot summer days. Fossil plants have been the target for significant NO_X reductions since the Clean Air Act Amendments were implemented. These included NO_X RACT, the NO_X SIP call (a cap-and-trade program for NO_X), and an EPA Clean Air Interstate Rule (CAIR) that was recently vacated by a court decision and then reinstated with directions to EPA to fix the program flaws.

7.2 NO_X and Reasonable Available Control Technology

The Clean Air Act Amendments established a requirement for *reasonable available control technology* (RACT) to help reduce the formation of NO_X and thus ozone and acid rain.[23] This NO_X reduction requirement is either an emission limit in lb/MMBtu or the requirement to use a specific NO_X control technology. Typically, states have implemented their own regulations for NO_X RACT.

[23] RACTs are air pollution control measures in CAAA nonattainment areas that are considered to be "reasonably available" when accounting for social, economic, and environmental impacts. State implementation plans include RACT requirements for reducing emission levels from existing sources. RACT measures typically are less stringent than best available control technologies.

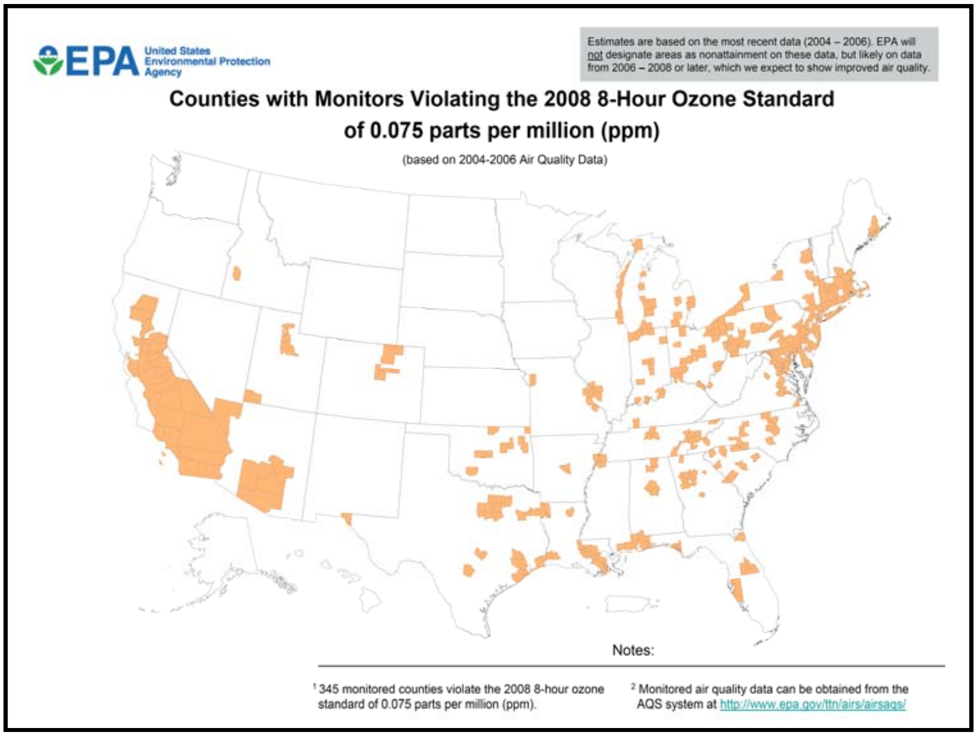

Figure 7-1: U.S. counties with monitors violating EPA's 2008 8-hour ozone standard of 0.075 ppm.

Source: U.S. EPA.

7.3 EPA's NO_X Budget Program and Clean Air Interstate Rule

In 1998, EPA established the "NO_X SIP Call" program, which is designed to mitigate the significant transport of NO_X by requiring states to reduce ozone-season NO_X emissions that contribute to ozone nonattainment in other states.[24] In 2003, EPA began administering the NO_X Budget Trading Program (NBP) under the NO_X SIP Call rulemaking. The NBP is a market-based cap-and-trade program for reducing emissions of NO_X from power plants (and other combustion sources) 15 MW or larger during the May through September ozone season. It covers a 19-state region that includes all the states served by the three ISO/RTOs. This program was scheduled to end this year and be replaced by EPA's *Clean Air Interstate Rule* (CAIR) starting in 2009.

EPA established CAIR in 2005 to take more aggressive steps to reduce precursors to ozone and particulates over a 28-state region. CAIR was intended to cap NO_X emissions at 1.5 million tons starting in 2009 and at 1.3 million tons in 2015. However, on July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the entire *Clean Air Interstate Rule* because it found a number of flaws with the rule.[25] Some states already may have passed rules that implement the obligations under CAIR and require generators to make compliance investments. While discussions continue on what

[24] Additional information on the NO_X SIP Call program and the NO_X Budget Trading Program is available online at the EPA Website, "NO_X Budget Trading Program/NO_X SIP Call;" http://www.epa.gov/airmarket/progsregs/nox/sip.html#sipcall.

[25] Kyle Danish, "United States: D.C. Circuit Vacates *Clean Air Interstate Rule*, Creating Uncertainty for Air Regulatory Programs," *Issue Alert* (July 14, 2008); http://www.vnf.com/assets/attachments/376.pdf .

should follow or replace CAIR, some states are reinstating their regulations for the NBP.[26] The ISO/RTOs are continuing to monitor and evaluate the impacts that this decision could have on their stakeholders.

7.4 High Electricity Demand Days (HEDD) Program

To further reduce NO_X emissions on ozone violation days, six states in the Northeast corridor have committed to reducing NO_X emissions on days with high electricity demand, which are proxies for high ozone days.[27] The correlation between HEDDs and instances of exceeding the ozone standard is shown in Figure 7-2 for Connecticut for the 2007 ozone season. The figure shows that the ozone standard was exceeded even at load levels below 70% of the summer peak for the state.

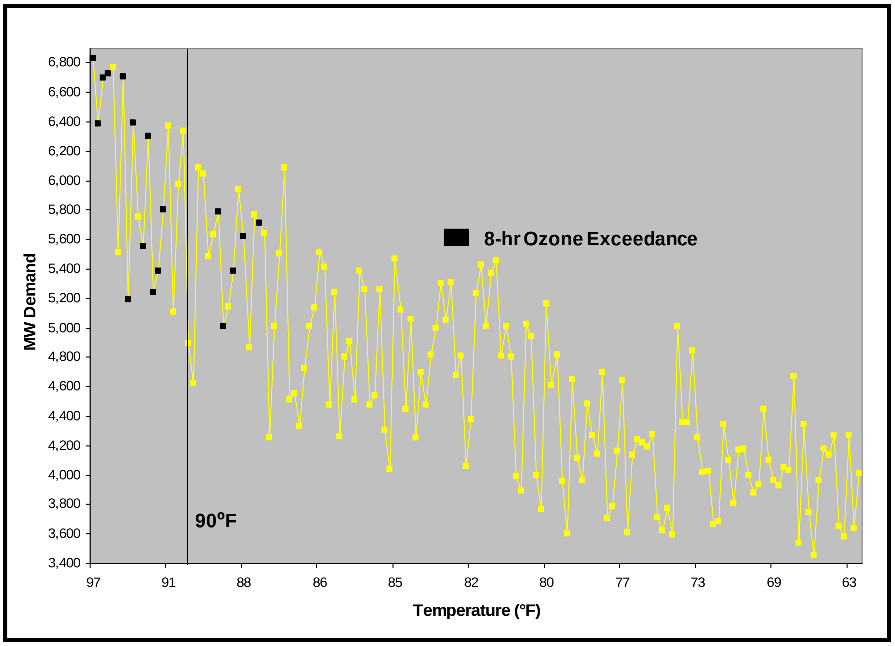

Figure 7-2: Connecticut's electricity load compared with ozone violations for the 2007 ozone season.

[26] Eric Groton, "EPA's *Clean Air Interstate Rule* (CAIR) Vacated by D.C., Circuit Court" (Austin, TX: Vinson and Elkins, LLP, July 2008); http://www.martindale.com/legal-articles/Article_Abstract.aspx?id=466838&isAuth=1.

[27] The other HEDD states are New York, New Jersey, Pennsylvania, Delaware, and Maryland.

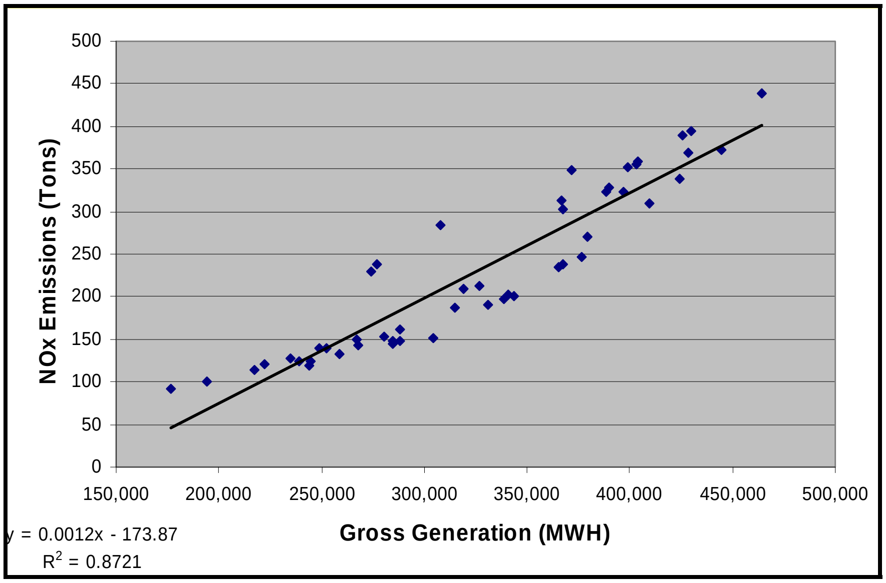

Figure 7-3: NO_X emissions vs. generation in New York on high ozone days 2005-2007

Figure 7-3 shows a strong correlation for NO_X emissions and generation in New York on high ozone days during the period 2005-2007.

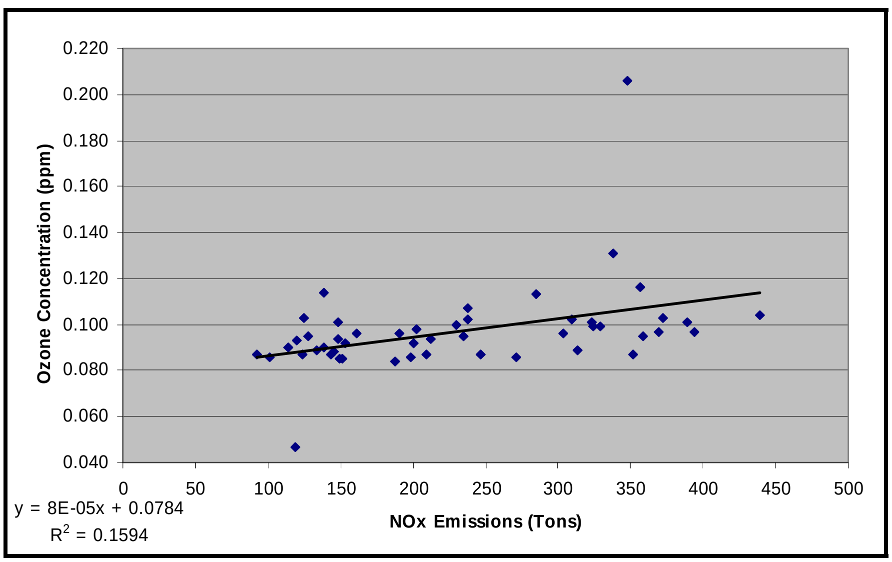

Figure 7-4: NYCA Net Generation vs. Ozone Concentration

However, the correlation between generation levels and ozone concentration in New York is much weaker, as shown in Figure 7-4. Following this correlation to its limit, we note that operating NYCA in a zero emissions mode (which is not possible) would still find exceedances of the standard, so it should be apparent that fossil generation is not the only contributing source to ozone non-attainment. This indicates the problem can only be solved on a regional basis controlling a variety of sources.

This six-state ozone attainment effort is coordinated under the OTC for the so-called Northeast "inner-corridor" states on HEDD days.[28] The total HEDD reduction commitment by the six states in the program is 135 tons and the commitment by each state is shown in Table 7-1.

Table 7–1
OTC States' HEDD Commitments

State	HEDD Commitment Tons
Connecticut	11.7
New York	50.8
New Jersey	19.8
Pennsylvania	21.8
Delaware	7.3
Maryland	23.5
Total	**134.9**

The Northeast States for Coordinated Air Use Management (NESCAUM) reported that oil-fired steam units and peaking turbines that have no NO_X controls generate a high proportion of NO_X emissions on peak ozone days.[29] Alternatives to meet these reductions include additional NO_X controls, repowering or retirement, and reducing output to meet the HEDD commitment. The interregional impact of the HEDD program could affect the reliability of the bulk electric power system across the three ISO/RTOs. Each state is developing its own strategy and regulations to implement its HEDD commitment.

7.5 Carbon Dioxide (CO_2)

This section outlines federal and state proposals to reduce greenhouse gases and focuses on the Regional Greenhouse Gas Initiative being implemented starting in 2009.

7.5.1 CO_2 Cap and Trade Programs

Given the potential for carbon dioxide to contribute to or cause global climate change, in April 2007 the U.S. Supreme Court ordered EPA to evaluate CO_2 as a potential pollutant to be regulated.[30] EPA has not yet made any regulatory decision on CO_2, and the northeastern states recently sued EPA for not acting on this requirement. In May 2008, EPA estimated that it would not issue any ruling for at least a year.[31] However, on July 11, 2008, EPA released an Advanced Notice of Proposed Rulemaking (ANPR) inviting

---

[28] *Memorandum of Understanding (MOU) Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electric Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning* (Washington, DC: Ozone Transport Commission, March 2, 2007); http://www.otcair.org/document.asp?fview=Report.

[29] *High Electric Demand Day and Air Quality in the Northeast* (White Paper) (Boston: NESCAUM; June 5, 2006); http://www.nescaum.org/documents/high-electric-demand-day-and-air-quality-in-the-northeast. NESCAUM is a nonprofit association of air quality agencies in the six New England states plus New York and New Jersey that provides scientific, technical, analytical, and policy support to the air quality programs of these Northeast states.

[30] Massachusetts et al. Petitioners v. EPA et al. (No. 05-1120), 549 U.S. 497 (Decided April 2, 2007); http://www.supremecourtus.gov/opinions/06pdf/05-1120.pdf.

[31] "EPA is reluctant to rule on U.S. carbon emissions," Point Carbon News, Vol. 3, Issue 10 (May 21, 2008); http://www.pointcarbon.com/polopoly_fs/1.917949!CMNA20080521.pdf.

public comment on the benefits and ramifications of regulating GHGs under the *Clean Air Act*.[32] Comments were due in late November 2008.

The U.S. Congress has proposed a number of bills that include cap-and-trade programs to reduce greenhouse gases and, in some cases, specifically CO_2. The bills have various dates for implementation, percentage reduction targets, and other features, but most propose to reduce GHG emissions from power plants and other sources by the 2050 timeframe.[33]

Some states already have undertaken initiatives to reduce greenhouse gases (GHGs). The Regional Greenhouse Gas Initiative (RGGI), an agreement started in 2003 among ten northeastern states[34], is a regional program that applies to fossil generating units larger than 25 MW. The western states also have initiated a greenhouse gas reduction plan broader in scope than RGGI, but it is not scheduled to go into effect until 2012.

Finally, some states (e.g. Connecticut and Massachusetts) have passed legislation setting short-term and long-term multi-sector goals for reducing GHGs.[35]

7.5.2 Regional Greenhouse Gas Initiative (RGGI)

RGGI is a commitment among ten Northeastern states to cap carbon dioxide emissions from fossil power plants 25 MW and larger in those states starting in 2009. The states include those served by ISO New England, NYISO and three states in PJM (NJ, DE and MD).

7.5.2.1 RGGI Basics

RGGI became effective January 1, 2009, capping CO_2 emissions from fossil fuel generating plants greater than 25 MW. The annual 10-state cap will be 188 million (short) tons. Each state is allocated a share of the cap as allowances[36] on the basis of historical emissions and negotiations, as shown in Table 7-2. RGGI specifies that the cap will stay at this level through 2014 and then decrease gradually by 10% by 2018 to 169.2 million tons. At that time, the allocation for the New England states would be reduced to 50.2 million tons and to 57.9 million tons in New York. The PJM states will have their cap reduced from 68.0 tons to 61.2 tons.

---

[32] "Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions under the Clean Air Act" (EPA-HQ-OAR-2008-0318; FRL-8694-2) (Washington, DC: EPA, July 11, 2008); http://www.epa.gov/climatechange/anpr.html.

[33] GovTrack.us. S. 2191—110th Congress (2007): *Lieberman-Warner Climate Security Act of 2007* (America's *Climate Security Act of 2007*), *GovTrack.us (database of federal legislation);* http://www.govtrack.us/congress/bill.xpd?bill=s110-2191 (accessed Jul 21, 2008). GovTrack.us. H.R. 6186—110th Congress (2008): *Investing in Climate Action and Protection Act, GovTrack.us (database of federal legislation)*; http://www.govtrack.us/congress/bill.xpd?bill=h110-6186 (accessed Jul 21, 2008).

[34] The six New England states, New York, New Jersey, Delaware and Maryland.

[35] *An Act Concerning Connecticut Global Warming Solutions,* (HB 5600) Public Act No. 08-98 (June 2, 2008); http://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm. *An Act Establishing the Global Warming Solutions Act* (Chapter 298 of the Massachusetts Acts of 2008; S.2540) (August 7, 2008); http://www.mass.gov/legis/laws/seslaw08/sl080298.htm.

[36] A CO_2 emissions allowance is a regulatory agency's authorization under the Regional Greenhouse Gas Initiative (RGGI) CO_2 trading program to emit up to one ton of CO_2 (subject to limitations of the initiative).

Table 7–2
RGGI State Annual Allowance Allocations for 2009 to 2014

State	CO_2 Allocation Million (Short) Tons
Connecticut	10.70
Maine	5.95
Massachusetts	26.66
New Hampshire	8.62
Rhode Island	2.66
Vermont	1.23
New York	64.31
New Jersey	22.89
Delaware	7.56
Maryland	37.50
Total RGGI	**188.08**

Each of the RGGI states has completed its final regulations to implement RGGI. Most are planning to auction close to 100% of their share of the RGGI allowances. In most cases, the funds raised from the auction of these allowances will augment the existing funding by electricity ratepayers of the states' to promote or reward investments in energy efficiency, renewable or non-carbon-emitting technologies, and/or innovative carbon emission abatement technologies with significant carbon reduction potential. Additional energy-efficiency measures, if effective, can slow growth in energy consumption and thus slow the growth in CO_2 emissions.

The RGGI organization developed a regional auction design to use for all the participating states.[37] The auction design is a single-round, uniform-price, sealed-bid format with a reserve price of $1.86/ton. The first auction was held on September 25, 2008, and six states participated. Over 12 million allowances were sold at a clearing price of $3.07. A second auction was held December 17, 2008. All ten states participated. Over 31.5 million allowances were sold at a clearing price of $3.38. Quarterly auctions will be held in the future.

Over 685 generators affected by RGGI will be required to demonstrate compliance with RGGI by having sufficient allowances in their allowance account to cover their CO_2 emissions over a three-year compliance period. The first deadline for this three-year "true-up" is March 1, 2012, for the first compliance period ending December 31, 2011. The generators will need to purchase these allowances in the RGGI auctions, 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. Generators also may use offsets created by reductions in GHG emissions in five sectors outside electricity generation. The allowable offsets include 1) capturing and combusting methane from landfill gas; 2) reducing sulfur hexafluoride (SF_6) leaks from electricity transmission and distribution equipment and recycling the SF_6; 3) improving propane, oil, and gas end-use efficiency; 4) Avoided methane emissions from agricultural manure management operations; and 5) taking up CO_2 through afforestation. The use of offsets will be

[37] "RGGI Allowance Auction Design," *Regional Greenhouse Gas Initiative* (2007); http://www.rggi.org/home.

allowed for meeting up to 3.3% of a generator's compliance obligation (i.e., total CO_2 emissions during the compliance period.) This offset limit could increase to 5% and 10% if the average cost of allowances increased above the CO_2-allowance trigger prices of $7/ton and $10/ton (plus adjustment for inflation for both prices), respectively.[38]

7.5.2.2 Impacts of RGGI

The economic impact of RGGI on affected fossil fuel generators will be the added cost of the CO_2 emissions allowances to the energy production (bid) cost of these generators. Because of higher CO_2 emission rates for coal-fired power plants, the added costs for these plants will be greater than the added costs for oil- and natural-gas-fired power plants. If the new RGGI allowance market operates as set forth by the modeling conducted by the state agencies, bulk power system reliability is not expected to be negatively impacted in the near term. If, on the other hand, market disruptions occur, the spread between natural gas pricing and coal pricing continues to dissipate, or the RGGI market converges with the world CO_2 allowance markets, availability of high carbon-emitting units will be affected. For example, convergence of RGGI allowance prices with the world CO_2 market would lead to allowance prices in the range of $35 to $50/ton and the possible exit from the marketplace of some of the coal capacity in the region[39].

Adding RGGI's new air emission requirement to fossil fuel plants could have an impact on the reliability of the bulk electric power system in the 10-state RGGI region. For example, a lack of liquidity in the allowance market, the retirement of allowances, higher energy demand, or poor operation of carbon-free resources potentially could lead to a shortage of allowances or offsets in the marketplace. Without enough of the allowances or offsets that RGGI requires, the number of hours that plants could operate could be restricted. While post-consumption SO_2 and NO_X control measures (i.e., scrubbers for SO_2 and selective catalytic reduction [SCR] for NO_X) serve to limit allowance prices, no post-combustion control options currently exist for CO_2, which could result in setting and capping CO_2 allowance prices. The owners of the affected facilities will need to consider the cumulative financial impacts of these regulations when making their plans for continued operation and investment. In a similar fashion, developers and owners of low- and non-emitting resources may hold an improved outlook for the viability of those resources. Another potential issue with RGGI is the intent of the RGGI organization to deal with "leakage."[40] A RGGI report documented the need to track energy imports into the RGGI region by modifying the current generation information systems of the ISO/RTOs in the RGGI region. The NEPOOL Generation Information System (GIS) has made these modifications and has been tracking imports and exports since January 1, 2008. While the RGGI organization has not gone further in its efforts to deal with leakage, it plans to evaluate this issue during the first three-year RGGI program review in 2012 after accumulating additional data.

Emission allowance costs will be one of the factors to be considered by fossil fueled generating plant owners when evaluating the continued viability of a generating unit. Fuel costs will also continue to be of primary importance to that analysis. In particular, fuel costs determine the incremental margin that will be

[38] When the 12-month average price trigger of $7/ton would be surpassed in the allowance market, and a 14-month market-settling period has transpired, a generator's percentage use of offsets could rise to 5% of its compliance obligation. Similarly, if the 12-month average price trigger surpasses $10/ton, the generator's use of offsets could increase to 10% of the compliance obligation.

[39] Based on historic EU-ETS prices, available from http://www.pointcarbon.com/.

[40] Leakage refers to an increase in lower-cost, imported power from non-RGGI control areas (i.e., Canada, the non-RGGI part of PJM, etc.). The concern is that this could increase the CO_2 levels in New England by higher-carbon-emitting plants located outside the RGGI states that are not subject to the RGGI cap. To some degree, imports could offset the intended CO_2 reductions within the RGGI states and thereby compromise RGGI's effect.

available in the energy markets. Historically, large coal-fired base-load units have depended upon fuel cost advantage to gain incremental revenues with which to offset some portion of fixed costs not recoverable in the capacity markets. Fuel costs over the past several years have become increasingly volatile as seen in Figure 7-5, leading to increasingly variable spreads between coal and gas fuel prices.

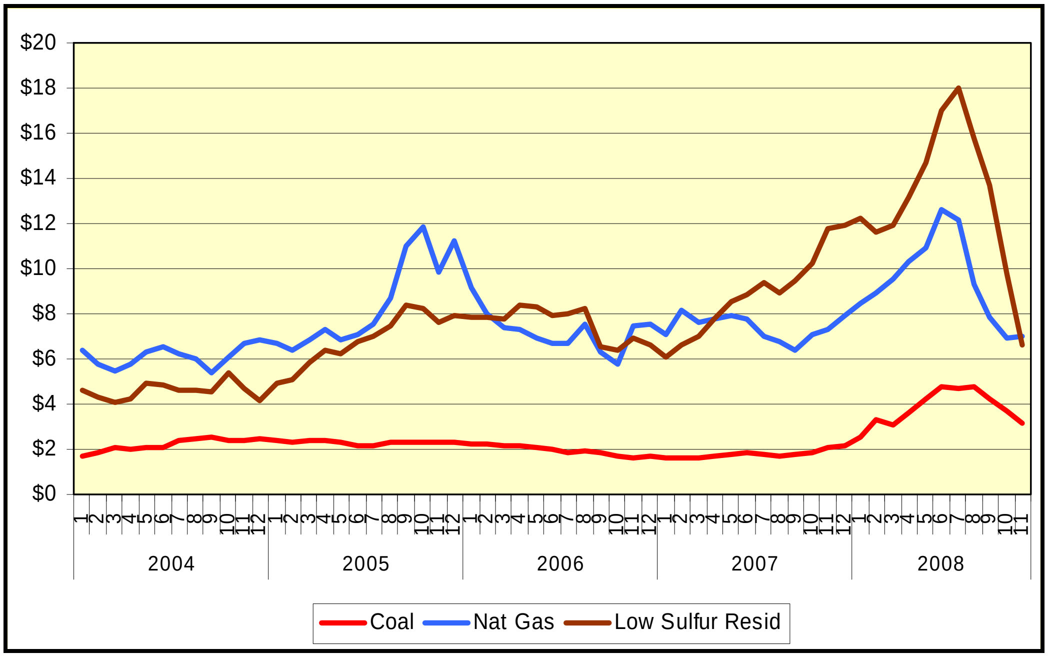

Figure 7-5: Fuel Price History - $/MMBTU[41]

The incremental reduction of CO_2 is achieved through a combination of the reduction of the use of electricity and switching from lower-cost, higher-emitting units to higher-cost, lower-emitting units. Typically, the unit that sets the marginal price emits CO_2. Therefore, the incremented cost of the reduction of CO_2 is typically the fuel cost for the marginal unit plus the price of emission allowances. The marginal unit in the NYCA and New England are most frequently fueled by natural gas.

7.5.3 Other GHG Programs

The Western Climate Initiative (WCI) is a proposed program to cap and then reduce greenhouse gas emissions from seven western states (CA, OR, WA, AZ, NM, UT, MT) and four Canadian provinces (BC, QUE, ONT, MAN). The equivalent CO_2 emissions to be capped are approximately 1,000 million tons as compared to the RGGI cap of 188 million tons, and covers other economy sectors in addition to electric generation. The WCI cap begins in 2012 and will decrease to a level that is 15% below 2005 emissions. The proposed program design and plan have been agreed to by each of the participants, which are now beginning the development of their own specific rules to implement the proposed program. The plan provides for the use of allowances from other greenhouse gas control programs such as RGGI. Up to 49% of the required reductions can be accounted for through the use of such allowances and offsets. Given the magnitude of this program, the level of support in participating governments, and the stage of program development, it is reasonable to consider the convergence of the RGGI allowance market with

[41] Based on US EIA historical fuel price data. http://www.eia.doe.gov/overview_hd.html

the WCI allowance market. The planners of WCI have estimated that allowance costs in 2020 may range between $22 and $65/ton depending upon the final amounts of offsets that will be allowed[42].

The European cap-and-trade system is much larger than RGGI, covering many economic sectors, and continues to grow through the addition of new members and sectors. Throughout 2008, European Union allowances have traded in the range of $35 to $50/ton. At these price levels most, if not all, of the margin available from the electric markets will have disappeared for coal-fired generators. Generally, coal-fired units have been relatively low in the dispatch offer/bid stack operating base load. With increasing allowance prices, these units' mode of operation could become more variable requiring other resources to also change operating modes. One outcome would be an increased use of gas. If allowance prices continue to increase further, coal capacity could exit the system. Towards the end of the planning horizon, this could impact reliability and place significant new demands on the market for Special Case Resources (SCR). The ISO/RTOs will continue to monitor this situation and adjust their plans accordingly.

7.6 Power Plant Cooling Water Issues

The principal water quality issue at power plants in the United States is reducing the entrainment and impingement impacts of cooling water intake structures and thermal discharge of heated water into water bodies to comply with the *Clean Water Act* (CWA). CWA Section 316(a) outlines the requirements for discharges into water bodies. Section 316(b) requires EPA to ensure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available to minimize adverse environmental impact.[43] National Pollution Discharge Elimination System (NPDES) permits are the compliance vehicle for meeting these requirements, which expire five years after issuance. (If EPA takes no action to renew a permit, the permit is stayed, which allows the facility to continue operating under the terms of the expired permit until it is renewed.) If a facility owner files a complete application for an NPDES permit reissuance at least 180 days in advance of the expiration date of the current permit, the owner of the facility can continue operating under the terms of the expired permit until it is renewed by permitting agency.

EPA implemented the Section 316(b) rule in three phases. Phase I, promulgated in December 2001, established standards for cooling water intake structures at new facilities (e.g., power plants and manufacturers) that withdraw more than two million gallons per day (MGD) from U.S. waters and use more than 25% of the water for cooling. New facilities with smaller intake capabilities still are regulated individually by site. The Phase I rule, in general, requires cooling towers; however, there is a means to get alternative approaches permitted.

Phase II affects large existing facilities designed to withdraw at least 50 MGD and use more than 25% of that water for cooling purposes. The final rule, promulgated in February 2004, established performance standards stating that the number of aquatic organisms that impinge on the intake screens must be reduced by 80 to 95% compared with uncontrolled levels, and the number of organisms drawn into the cooling system must be reduced by 60 to 90%. The rule, which affects over 500 power plants in the United States, allows a number of compliance alternatives using fish-protection technologies and restorative measures. Although a July 2007 federal court ruling suspended Phase II performance standard requirements, EPA has since clarified that permitting authorities still must develop *best professional judgment* controls for

[42] See table B-12 of WCI Design Report for the Western Climate initiative, http://www.westernclimateinitiative.org/ewebeditpro/items/O104F20432.PDF (prices here are based on conversion from metric tons to US tons). The document also includes historical trading prices for carbon allowances in the European Union.

[43] "Cooling Water Intake Structures," *CWA Section 316(b); Phase I—New Facilities. Fact Sheet. EPA-821-F-01-01* (Washington, DC: U.S. EPA, November 2001); http://www.epa.gov/waterscience/316b/phase1/316bph1fs.html.

the cooling water intake structures of existing facilities and that these controls must reflect the best technology for minimizing adverse environmental impacts.[44] (Facilities must renew their cooling water permits before they expire, for which EPA is providing case-by-case guidance.) A January 25, 2007, federal court decision remanded a number of key elements back to the EPA. This led to EPA suspending the rule in July 2007. While the Phase II rule is suspended, EPA directed the states to make best professional judgment decisions.

Phase III of the rule, in effect since 2006, affects existing facilities other than power plants, such as manufacturers and new offshore and coastal oil and gas extraction facilities. Phase III applies to existing smaller power plant intakes with a design intake flow of less than 50 million gallons per day.

NPDES permit renewals may require existing plants to add cooling towers to comply with water intake and discharge regulations. These could significantly extend the times plants are off-line for maintenance and increase the costs for those plants. Compliance with any future revised NPDES permits or 316(b) rules by affected plants in New England, New York, and PJM states could have an impact on system reliability that is unknown at this time. These potential impacts may need to be evaluated further.

7.7 Summary

Planned and pending environmental regulations may change the capacity mix of resources and the economic dispatch of generation. The regulations could also result in generators respecting energy or other restrictions that could also lead to retirements. It is vital that the ISO/RTOs continue to monitor the situation to ensure that the interregional system remains reliable and that there are ample opportunities to exchange economical power while respecting environmental constraints.

[44] EPA's suspension of Phase II of the CWA Section 316(b) was in response to the Second Circuit Court of Appeals decision in Riverkeeper, Inc., v. EPA, 475 F.3d 83 (2d Cir., 2007). Additional information is available online at EPA's Web site, "National Pollutant Discharge Elimination System—Suspension of Regulations Establishing Requirements for Cooling Water Intake Structures at Phase II Existing Facilities" (Washington, DC: U.S. EPA, July 9, 2007); http://www.epa.gov/fedrgstr/EPA-WATER/2007/July/Day-09/w13202.htm. Also see the ISO's "Summary of Meeting #6, 5.0 Environmental Issues for RPS08," Environmental Advisory Group Minutes (February 29, 2008); http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/eag/mins/2008/draft_eag_mtg_6_summary_2-29-08.pdf.

8. Renewable Resource Development

Renewable resource development is being driven mostly by renewable portfolio standards (RPS) that most states throughout the three ISO/RTOs region have established. Table 8–1 shows that most of this development consists of wind resources and, currently, there is over 61,000 MW of wind projects in the three ISO/RTO queues, mostly in PJM. Much is being done to analyze and develop ways to smoothly integrate wind into the operation of each ISO/RTO. NYISO and PJM already have significantly more MW of wind resources operating in their regions than ISO New England.

Table 8–1
Renewable Resource Projects in the ISO NE, NYISO and PJM Queues – MW (# of Projects)

ISO/RTO	Onshore Wind	Offshore Wind	Biomass	Hydro	LFG	Fuel Cells	Solar	Total
ISO NE[(a)]	3,038 (36)	1,259 (3)	456 (10)	16 (3)	47 (3)	59 (3)	0	4,875 (58)
NYISO[(b)]	6,705 (66)	1,261 (3)	7 (1)	148 (5)	43 (8)	0	0	8,164 (83)
PJM[(c)]	46,646 (222)	2,316 (7)	572 (19)	2,289 (36)	368 (72)	0	59 (6)	52,250 (362)
Total	**56,389 (324)**	**4,836 (13)**	**1,035 (30)**	**2,453 (44)**	**458 (83)**	**59 (3)**	**59 (6)**	**65,289 (503)**

(a) Based on September 10, 2008, Interconnection Queue

(b) Based on October 30, 2008, Interconnection Queue

(c) Based on November 2008 Interconnection Queue

8.1 New England

Five of the New England states have RPSs that focus on developing new renewable resources. They also include existing resources and, in some states, special categories for combined heat and power (CHP) and energy efficiency (EE). Vermont has a renewable resource development goal but no RPS. These RPSs and renewable goals are summarized for the New England states in Table 8–2 below. Considering all of these programs, the New England goal for 2020 is to have almost 28% of its energy derived from renewable resources and energy efficiency measures.

Table 8–2
Projected New England Requirements for Electricity Generation from Existing, New, and Other Renewable Resources and Energy Efficiency, based on the ISO's RPS08 Forecast of Annual Electric Energy Use (GWh and %)

Line #	Use/Requirement Category	2007	2008	2012	2016	2020
1	**2008 ISO electric energy use forecast**	132,615	135,000	140,425	144,395	147,947
2	**Existing—RPS requirements for existing resources**[a]	4,681	5,219	5,904	6,112	6,301
3	**New—RPS requirements for new resources**[b]	2,764	3,726	8,002	13,065	17,796
4	**Other—other requirements for new renewables**[c]	0	16	402	823	1,263
5	**Energy efficiency—requirements for new energy efficiency and CHP**[d]	322	647	5,748	10,375	15,717
6	**Total RPS and other requirements**	**7,768**	**9,608**	**20,055**	**30,375**	**41,077**
7	**Total RPS and other requirements as a percentage of New England's projected electric energy use**[e]	**5.9%**	**7.1%**	**14.3%**	**21.0%**	**27.8%**

(a) This category includes ME Class II, RI Existing, and NH Classes III and IV. These requirements grow through time as a result of the growth in electricity demand. NH's classes also include some growth in the use of renewable resources to meet the required percentage of electric energy use.

(b) This category includes CT Class I, ME Class I, MA Class II, RI's "new" category, and NH Classes I and II.

(c) This category includes VT's goal of having renewable resources meet 25% of the demand for electric energy by 2025.

(d) This includes CT Class III (energy efficiency and CHP) and accounts for MA's goal of 25% energy efficiency by 2020 from its Green Communities Act.

(e) The numbers may not add to the totals shown due to rounding.

While energy efficiency (EE) represents a large portion of this requirement, due mostly to a new Massachusetts goal of meeting that state's electric energy requirements with 25% energy efficiency by 2020, most of the growth would come from the new renewable resource category.

Figure 8.1 shows the growth in the incremental new renewable goals beyond 2007 to 2025, compared to the projected energy from all the renewable projects in ISO-NE's queue assuming typical capacity factors for the renewable technologies.

Figure 8-2 shows the breakdown of the queue by resource type, and that onshore and offshore wind together would provide close to 90% of this new renewable energy, assuming all these projects would be built and operate as planned. Historically, about 60% of the capacity in MW in the queue has not been developed, and based on the number of proposed projects the percentage would be even higher.

While Figure 8-1 shows that the renewable projects in the ISO New England queue would likely meet the RPS up to 2022, this assumes that all of them would be built and would provide the RECs for the total New England states' RPSs. So given the attrition history of queue projects, the need for more projects, purchases of RECs, or use of alternative compliance payments will likely be required sooner than shown in Figure 8-1. In any case, new projects will likely enter the queue and there are ongoing discussions with Eastern Canada about importing renewable energy into New England, mostly wind and hydro. Massachusetts is already buying RECs from wind projects in Eastern Canada.

There are projects due on-line this year that will come under the energy management of ISO New England and rapid growth is expected over the next few years, as seen in Figure 8-1[45]. ISO-NE is planning for the integration of this growth and investigating the system integration, operating and market needs to accommodate this growth in wind.

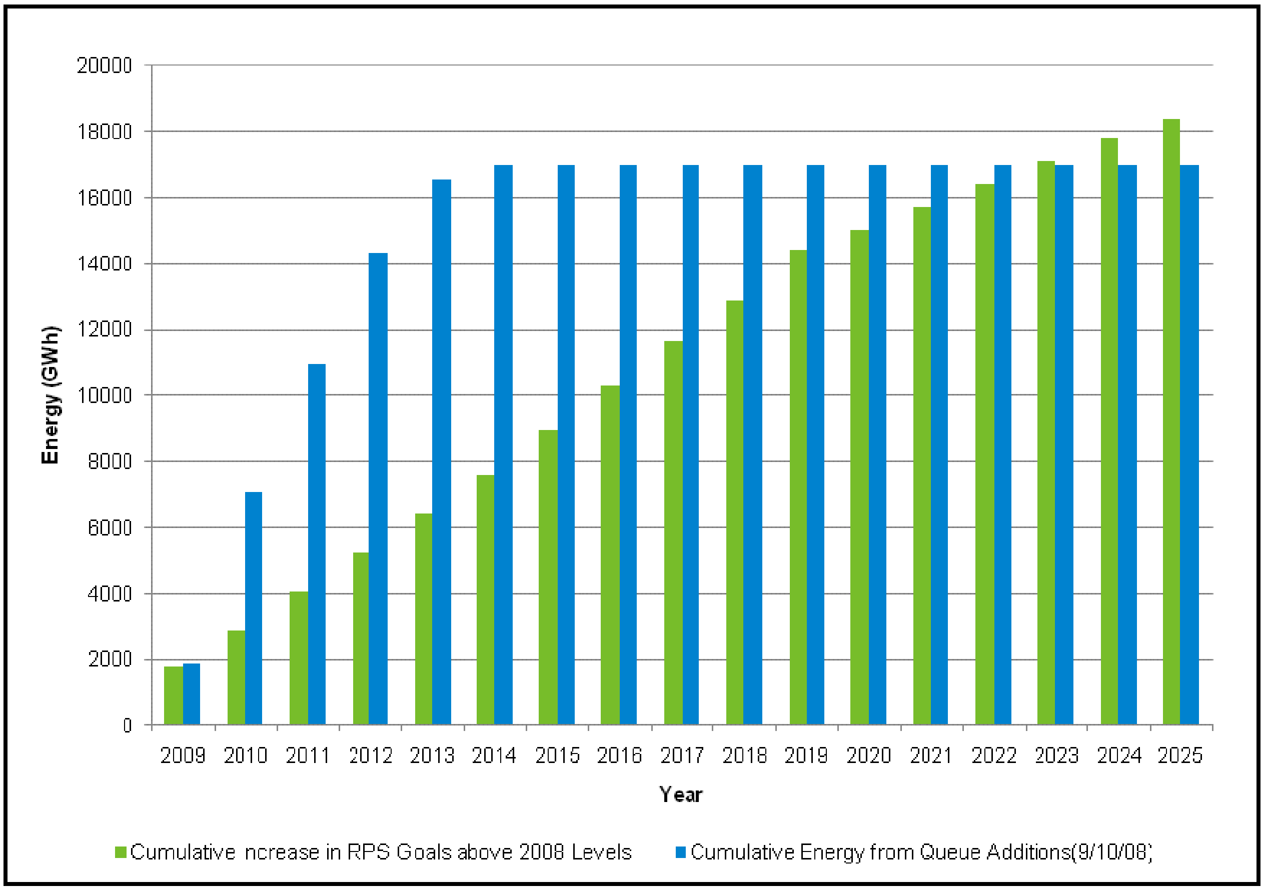

Figure 8-1: New Incremental RPS for New England vs. Projected Annual Renewable Production

[45] The increase in RPS Goals is the amount of increase relative to the 2007 targets.

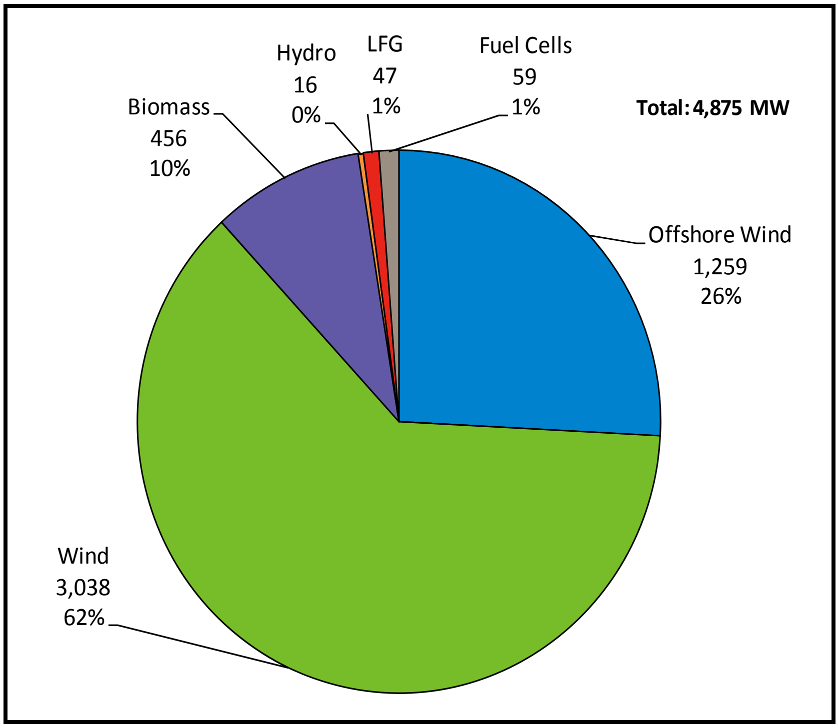

Figure 8-2: Renewable Resources in the ISO New England Interconnection Queue as of 9/10/08

8.2 New York

New York has an RPS requirement that 25% of its energy come from renewable resources by the year 2013. New York is already meeting about 19% of its RPS requirement with renewable resources (mostly hydro), and thus needs an additional 6% to satisfy the goal, or about 10 million MWh. The NYISO Interconnection Queue Report shows 69 wind projects in the interconnection process with a total capacity of 7,966 MW. The report also shows five hydro projects with a combined capacity of 148 MW. Biomass and landfill gas projects in New York currently total 50 MW and tend to be of a size or at an interconnection voltage that does not put them under the jurisdiction of the NYISO.

NY's RPS program is funded through a surcharge on the customer bills from investor-owned utilities. The New York State Energy Research and Development Authority (NYSERDA) will conduct annual auctions for the purchase of Renewable Energy Credits (RECs) which are proposed to be produced from new qualified renewable generation facilities. The New York State Public Service Commission (NYSPSC) has proposed an increase in the funding and an extension of the program target date for the RPS program. The proposal raises the target to 30% and extends the target date to 2015.

8.3 PJM States

In PJM, Pennsylvania, New Jersey, Delaware, Maryland and the District of Columbia have RPS requirements. New Jersey has an aggressive RPS requirement of 22.5% by the year 2021. Pennsylvania requires 18% by the same period. Delaware requires 10% by 2019, Maryland requires 7.5% by the year 2019, and DC requires 11% by 2022. The capacity of renewable projects in the PJM queue is shown in Table 8–1. The PJM Interconnection Queue Report shows that there are 362 projects with a total nameplate capacity of 52,250 MW. The report also shows a meaningful quantity of hydro, biomass, and methane projects.

8.4 Conclusions

As a result of the considerable renewable development planned in the Northeast, there is a reasonable probability of meeting the near-term Renewable Portfolio Standards through renewable projects in the three ISO/RTO queues. Over the longer term, RPSs may be met through the development of more projects in the queues of ISO-NE, NYISO, and PJM. However, this could require the need for additional transmission development between the regions. In addition, the neighboring Canadian regions may provide an additional source of renewable energy. Alternatively, there may be some combination of reduced load energy consumption and load making alternative compliance payments that serves as a cap on the price that loads would need to pay for renewable resources to meet RPSs.

9. Demand-Side Resource Development

Demand-side resources ("DSRs," also known as demand resources) include demand response (DR,also known as active resources) and behind-the-meter ("BTM") generation and energy efficiency (EE, also known as passive resources) that are technically capable of providing the service needed. Energy efficiency covers technology improvements that achieve permanent reductions in energy consumption at electric customer sites. Examples include high-performance new buildings, thermal envelope improvements, high-efficiency HVAC systems, and advanced lighting. Demand response is a specific type of demand-side resource in which electricity consumers modify their electric energy consumption in response to incentives based on wholesale market prices. Behind-the-meter distributed generation refers to customer-sited generation facilities, including combined heat and power, renewable resources, and other distributed resources. The best locations for these types of resources are in areas where they can help serve load, reduce transmission congestion, and improve system reliability. Emergency diesel generators have permitting restrictions, but can serve a reliability function.

Increased reliance on DSRs has been demonstrated most recently by ISO New England's integration of EE resources into its forward capacity market ("FCM") and PJM's recent tariff amendment filing to allow EE resources to participate in its capacity market, the Reliability Pricing Model ("RPM"). Also, New York State has begun implementation of a plan to reduce energy consumption by 15% from forecasted levels by 2015 through reliance on EE resources and opened an ongoing docket to assess an Energy Efficiency Portfolio Standard.

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.[46] 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 ISO New England

Recognizing the application of DSRs, the ISO New England 2008 Regional System Plan ("RSP") states that demand resources of all types may provide reserve capacity and relief from capacity constraints, or they may support more economically efficient uses of electrical energy.[47] Referring to demand resources as an important component of well-functioning wholesale markets, the ISO has allowed DSRs to participate in its first two Forward Capacity Auctions ("FCAs").

During the first Forward Capacity Auction, 2,279 MW of demand resources cleared and will count toward satisfying the net Installed Capacity Requirement (NICR) of 32,305 MW for the delivery year 2010/2011. Of the 2,279 MW that cleared, 700 MW, or 31%, represents passive demand-response resources, and 1,579 MW, or 69%, represents active demand-response resources. In the second FCA, approximately 2,900 MW of demand resources cleared the auction including 1,000 MW of passive demand-response resources. To meet the ICR requirements imposed under the market rules, the active demand-response value includes a 600 MW cap placed on the use of emergency generators.

---

[46] *PJM*, 119 FERC §61,318 (June 25, 2007), pp. 79-80 and fn. 158.

[47] ISO New England 2008 Regional System Plan, p. 45.

RSP08 reports on a stakeholder process to address operational, planning, and market issues presented by this large penetration of demand-response resources.

9.2 PJM

On December 12, 2008, PJM filed a tariff amendment with the FERC to allow it to integrate EE resources into the RPM for participation in the May 2009 Base Residual Auction ("BRA") and delivery in 2012-13. If this filing is accepted, PJM will use the amount of EE resources that clear in the May 2009 auction as a starting point to develop an EE forecast for beyond 2012-13.[48] Demand-side resources are presently incorporated into the PJM planning process consistent with PJM Manual 14-B – PJM Region Transmission Planning Process.[49]

9.3 New York ISO

The NYISO offers two demand-response programs to support reliability: the Emergency Demand Response Program ("EDRP") and the Installed Capacity-Special Case Resource Program (ICAP/SCR). Demand-response resources may also participate in the NYISO's energy market through the Day-Ahead Demand Response Program ("DADRP") or the ancillary services market through the Demand-Side Ancillary Services Program ("DSASP"). EDRP provides demand-response resources with the opportunity to earn the greater of $500/MWh or the prevailing locational-based marginal price ("LBMP") for energy consumption curtailments provided when the NYISO calls on them. The ICAP/SCR program allows end-use customers that meet certification requirements to offer unforced capacity ("UCAP') to Load Serving Entities ("LSEs"). Special Case Resources can participate in the ICAP Market just like any other ICAP Resource. Resources are obligated to curtail when called upon to do so with two or more hours notice, provided that they are notified the day ahead of the possibility of such a call. The Targeted Demand Response Program ("TDRP") was introduced in July 2007. TDRP is a NYISO reliability program that deploys existing EDRP and SCR resources on a voluntary basis, at the request of a transmission owner, in targeted subzones to solve local reliability problems. The TDRP program is currently available in Zone J, New York City. Subscriptions to the NYISO's demand-response programs are at record levels. In 2009, 2,084 MW of ICAP/SCR resources will be on line, which is an increase of 761 MW over the 1,323 MW of resources in 2008. This additional SCR program participation significantly contributed to the NYISO determining that resource adequacy requirements will be met for the 2009-2018 study period.

In its 2009 Reliability Needs Assessment ("RNA"), the NYISO also included an analysis of the reliability impacts of New York's energy-efficiency initiative, which is intended to achieve a 15% reduction in energy use by 2015 ("15 X 15").[50] Pursuant to its Energy Efficiency Portfolio Standard, the New York State Public Service Commission (NYPSC) has taken initial steps to implement the New York Governor's initiative to lower energy consumption on the state's electric system by 15% of 2007 forecasted levels in 2015. Using a conservative assumption based on the current authorized funding level of $335 million per year, the NYISO determined for its base case reliability analysis that approximately 30% of the 15 x 15 goal would be achieved for reliability planning purposes. At that level, the energy efficiency savings equated to a 2,100 MW decrease in the peak load forecast. This reduction in peak

[48] For more information, see the PJM load report at http://www.pjm.com/planning/resource-adequacy-planning/~/media/documents/reports/2009-pjm-load-report.ashx

[49] The m14b is available from PJM's website, at http://www.pjm.com/~/media/documents/manuals/m14b.ashx

[50] NYISO Comprehensive Reliability Planning Process (CRPP) 2009 Reliability Needs Assessment, January 13, 2009, pp. 3-3 through 3-7.

demand contributed significantly to the NYISO's determination that no new resources will be needed on the New York bulk power system for 2009-2018. The NYISO will vigilantly monitor the implementation of the 15 x 15 programs to determine that they are in fact achieving their desired energy savings and peak demand reduction effects.

Finally, it should be noted that the NYPSC recently commenced a proceeding "to examine potential initiatives to promote demand response in parts of the state where peak load reduction would provide the greatest benefits."[51] The NYISO will fully participate in this proceeding.

9.4 Conclusion

Reliable and cost-effective DSRs are given full and fair consideration, along with other resources available to address grid reliability and economic congestion problems, in the existing regional planning processes. Those processes recognize the increasing presence of DSRs in the system, and integration issues are being addressed and coordinated by the ISO/RTOs.

[51] NYPSC Case 09-E-0115, Proceeding on Motion of the Commission to Consider Demand Response Initiatives, Order Instituting Proceeding (February 17, 2009).

10. Plans for Additional JIPC analysis

Anticipated future interregional analyses are discussed in this section. The scope of work, assumptions, and review of draft results are subject to open stakeholder review provided by the IPSAC.

10.1 New England/NY Focused Analysis

As discussed in Section 4.4, additional joint studies between New England and New York of an interconnection between Plattsburgh and Vermont will be required. The system benefits, alternatives, and final solution will be reviewed in the open stakeholder process. An upgrade of the 230 kV system to 345 kV throughout the New York North Country and conversion of any new interconnections to 345 kV may be considered as an ultimate transmission plan for this area.

The desirability of a new tie between Southwest Connecticut and New York may also be examined. While previous analysis showed little short-term benefit of such a tie, the ISO/RTOs will remain alert to opportunities that provide mutual benefits. Several long-term considerations are:

- The need for reliability of service to large load centers in Southeast New York and Southwest Connecticut
- Transmission limitations constrain transfers along the Hudson Valley and from Westchester to NYC
- New York–PJM transfer limitations may be relieved as the result of a new tie
- Connecticut is constrained by N-1-1 limitations, such as combinations of 345 kV transmission circuits into Connecticut and the Millstone generating unit, and the New England North–South Interface may constrain transfers within New England
- A desire to increase the loss-of-source limit in New England

The study would be performed with assumptions used in the NY and NE regional system plans for 2018, and would reflect potential improvements in NY and PJM, such as new interconnections between NY and PJM and transmission improvements between Ramapo to Pleasant Valley. Options may include:

- Interconnecting Pleasant Valley with a new 345 kV tie to Long Mountain, Southington, Frost Bridge, or Norwalk
- An HVDC interconnection between Ramapo or downstate NY with either Norwalk or East Shore

10.2 PJM / NY Focused Analyses

PJM and NYISO are developing a scope of work for additional interregional analysis. The overall joint study will consist of both a reliability analysis and a market efficiency analysis. The first phase of the study will focus on reliability analysis and the second phase will focus on a market efficiency analysis of potential transmission enhancements identified in the reliability analysis. These studies will be coordinated with ISO New England.

10.2.1 Reliability Analysis

The scope of the study will include development of a joint 2013 NYISO and PJM model, which will integrate the PJM 2013 RTEP model and the NYISO 2013 model. Both models will reflect the 2013 summer peak load levels.

The study activities will include the following:

- Perform an N-1-1 contingency analysis for all 230 kV and higher voltage facilities. The purpose of this analysis is to identify any potential N-1-1 reliability violations that have not been identified by either PJM's or NYISO's internal reliability analysis.
- Perform generator deliverability testing, per the standard procedures of each ISO/RTO, while monitoring facilities in the adjacent ISO/RTO. The purpose of this analysis is to identify any potential generator deliverability constraints on the combined NYISO/PJM model that may not have been identified in each ISO/RTO's individual transmission expansion plan.
- Generator deliverability will be tested for PJM generation to PJM load and NYISO generation to NYISO load while monitoring facilities in the adjacent area.
- Analyze peak (90/10) summer conditions while simulating a capacity deficiency in the combined Con Ed and Northern PSE&G system. Perform N-1 analysis of 230 kV and above facilities to identify potential constraints for the stressed conditions.
- Perform sensitivity analysis on credible retirement scenarios for critical transmission contingencies identified above.
- Develop potential transmission overlay options to resolve the issues identified in the reliability analysis.

10.2.2 Market Efficiencies

The future interregional studies planned that are related to market efficiencies include:

- Complete a market simulation of the combined NYISO/PJM system
- Identify areas with the highest LMP spreads
- Identify facilities producing the highest projected congestion
- Test the market efficiency impact of the potential solutions identified as part of the reliability analysis

The study's proposed schedule is to complete the reliability analysis by mid-2009 and the market efficiency analysis by the end of 2009.

10.3 Transmission Cost Allocation

FERC's policies regarding planning and cost allocation for ISO/RTOs have evolved since the issuance of Order 888, which did not include a planning requirement for ISOs. Order 2000, however, included a planning requirement for those entities that would voluntarily apply for RTO status. This Order has been the primary vehicle that the Commission has employed for expanding the RTO planning requirements from reliability to economic planning as well as the incorporation of cost allocation provisions in RTO Tariffs. Finally, Order 890 has now made it a requirement that all Transmission Providers, including ISOs and RTOs, have a formal planning process in their respective Tariffs, which includes reliability and economic planning as well as cost allocation provisions. At this time, FERC has accepted the Order 890 Planning Compliance Filings for all ISOs and RTOs, including PJM, NYISO and ISO-NE. Therefore, while further compliance filings are still pending, all ISO/RTOs now have FERC-accepted planning and cost allocation processes in their respective Tariffs.

Order 890 proposed nine “planning principles” that all Transmission Providers were required to meet in the development of their respective planning processes: coordination, openness, transparency, information exchange, comparability, dispute resolution, cost allocation, economic studies, and regional participation. Since the Commission directed each ISO/RTO to develop the specifics of its proposals with its respective stakeholders and to recognize regional needs, the result is that, while similar, there are differences in the approaches employed by each region. These differences are especially noted in the respective cost allocation provisions, which range from regionalization of transmission costs in ISO-NE to other “beneficiaries pay” approaches in NYISO, while PJM employs a hybrid approach that is dependent upon voltage level. A summary of the cost allocation provisions of all ISOs and RTOs can be found in the Appendix.

It should be noted that while cost allocation provisions for reliability projects have been in place in some regions for many years, application of economic cost allocation provisions is still in its relative infancy—especially in the Northeast. While FERC has approved much of PJM’s updated economic cost allocation methodology, there are aspects of it that are still under development. FERC has just approved the NYISO’s economic planning and cost allocation methodology as part of its Order 890 compliance filing, clearing the way for the NYISO to begin its economic planning process in mid-2009. While ISO-NE has had economic cost allocation provisions in its Tariff for several years, it is now in the process of reviewing their application with its stakeholders and state agencies.

It is also important to understand the differences in the approach to cost allocation that have been developed by each of the ISO/RTOs in conjunction with stakeholders and state agencies before proceeding with discussions concerning interregional cost allocation. The approach taken by PJM and MISO in the development of interregional cost allocation for reliability projects, and currently under consideration for economic projects, started with a comparison of their respective regional approaches. To date, PJM and MISO are the only entities that are under a FERC directive to develop a cross-border cost allocation methodology, deriving from the original PJM/MISO Seams Elimination Cost Adjustment (“SECA”) proceeding in 2004. Now that their respective individual cost allocation procedures have been substantially finalized by the Commission, NYISO and PJM have agreed to begin discussions regarding cross-border cost allocation following completion of the planning studies outlined in Section 10.2 above. Further stakeholder discussions will be conducted in an open and transparent process, including stakeholders in both regions.

ISO-NE will explore cross-border cost allocation once it completes its internal stakeholder process on cost allocation within New England and specific projects have been identified for consideration.

10.4 Summary

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.

11. Summary and Conclusions

The studies and activities covered in this report demonstrate that considerable interregional planning is being performed by ISO New England, NYISO and PJM under the joint Protocol. The Loss-of-Source (LOS) studies confirm the limits on interregional transfers and are examining the benefits that new ties can bring. With the addition of the 500 kV and 765 kV lines within PJM, LOS analysis confirmed that these additions will not increase the overall LOS limit and dynamic analysis confirmed that the system would be stable. A North Country wind study is focusing on the electrical integration of wind projects in northern New York. Related to this wind development is a Plattsburgh–Vermont tie study to increase transfers between New York and Vermont. Projects in the respective ISO/RTO queues near the interfaces have been examined for any interregional impacts. An analysis of loop flow between New York and New England has confirmed that the simplified modeling of load zones is adequate for multi-area resource adequacy studies. Even so, study results show that loop flow is a factor that must be considered in transmission analysis and transmission planning studies. Additional resource adequacy, transmission reviews, and stability analyses by NPCC and RFC help confirm the sound performance of the interregional power system over a wide footprint.

Because of the large growth in wind energy throughout the Northeast, much analysis is being done by the three ISO/RTOs for wind development and wind integration. The Joint Coordinated System Plan (JCSP) is studying conceptual scenarios of large wind (and coal) development in the Midwest and potential means for transmitting the energy to the Northeast. Each ISO/RTO is addressing issues on wind integration as they relate to their specific systems and level of development. The total region of the three ISO/RTOs has over 61,000 MW of wind projects in their combined queues, of which over 90% is onshore wind. In addition, the proximity of the Northeast to neighboring Canadian provinces that are developing hydro and wind projects may provide additional opportunities to supply the ISO/RTOs with renewable sources of energy.

Emerging environmental issues are important and can affect the reliability of the system as large numbers of generators could become affected by pending regulations. Three such issues are the six-state High Electric Demand Days commitment to reduce NO_X emissions on peak electric demand days as a proxy for days with high ozone levels, the Regional Greenhouse Gas Initiative (RGGI) which is implementing a CO_2 emissions cap starting in 2009 on the larger generators in New England, New York and three PJM states, and the potential for many existing power plants to be required to install cooling towers or their equivalent to reduce impacts on aquatic species and organismsentering the plants' cooling system.

As each ISO/RTO adds new resources and transmission to meet its own load growth and system development needs, these changes can affect the transfer of power among them and interregional system performance, thereby justifying further interregional analysis. Recognizing this and the need to further enhance interregional planning efforts, the ISO/RTOs have initiated a number of new technical studies that include the examination of possible new ties, production cost, and environmental analyses. The ISO/RTOs account for the use of demand resources and are coordinating integration issues. The ISO/RTOs are also in the nascent stages of developing plans for discussing interregional cost allocation. The ISO/RTOs regularly provide the status of "seams issues" including the schedules for addressing the planning issues and studies identified in this report. The Seams Report is noticed by the FERC and can be found at http://www.iso-ne.com/regulatory/seams/2008/index.html.

While much has been accomplished under the Joint 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 inter-regional planning for the Northeast and beyond. The efficiencies to be gained by trading electric power capacity and energy with other systems will most likely become even more advantageous over time. Such enhanced capabilities will also facilitate meeting RPS requirements, the RGGI ten-state CO_2 emissions cap, and other environmental requirements. Providing better access to generation resources that use a wide variety of fuels will improve the overall reliability and economic operation of the Northeast bulk power system. For all these reasons, a robust inter-regional planning process is essential. The Northeast ISO/RTOs are committed to the advancement of this process, in collaboration with their stakeholders.

12. Appendices

12.1 Cost Allocation Matrix of the ISO/RTOs

This section provides a summary of the cost allocation methods of the ISO/RTOs PJM, SPP, MISO, NYISO, ISONE, ERCOT, and CAL-ISO.

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

Reliability Upgrades	▪ **RTEP baseline facilities at or above 500 kV voltage level**
	- Also includes costs of those related facilities below 500 kV 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, per respective Interconnection Service Agreements.
	
	▪ **Baseline BELOW 500 kV…**allocation process pending before FERC with respect only to appropriate allocation to merchant transmission exports
	- 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**
	- Transfer distribution factor (DFAX) analysis to calculate each RTO’s flows affecting a constrained facility that a proposed cross-border facility is to relieve
	- 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.
		▪ **Baseline BELOW 500 kV for cost assignment to merchant transmission**
		- Cost assignment for reliability upgrades awaiting FERC action in pending dockets
		  - Merchant transmission developers believe that they should either have no cost allocation for future transmission system upgrades or that they should only have allocations for upgrades that are not related to load growth
		  - Other parties believe that allocations to merchants should be based on firm withdrawal rights specified in ISAs

PJM	PJM -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
Economic Upgrades	▪ **AT OR ABOVE 500 kV** - 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 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	▪ **BELOW 500 kV, ECONOMIC ONLY.** - FERC, per a 7/29/08 order, required parties to file a methodology within one year ▪ **BELOW 500 kV for cost assignment to merchant transmission.** - Cost assignment for economic upgrades awaiting FERC action in pending dockets order

SPP	SPP -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
Reliability Upgrades	▪ **All voltage levels, upgrade cost > $100,000…** - 1/3 of revenue requirement for upgrade is allocated regionally via postage stamp rate. [per SPP OATT, Attachment J] - 2/3 allocated to zones based on each zone's share of incremental positive MW-mile benefits…yielding Base Plan Zonal Annual Transmission Revenue Requirement (BPZATRR), [per SPP OATT, Schedule 11] - Each network load customer and TO charged - (1/12) x (zonal load ratio share) x (BPZATRR)	

<table>
<tr><th rowspan="2">SPP</th><th colspan="2">SPP -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Economic Upgrades</td><td>▪ All voltage levels. Paid by the project sponsor. The sponsor is provided revenue credits for subsequent service SPP is able to sell because of the upgrades.</td><td>[Subject of pending August 15, 2008 SPP FERC filing.]
▪ 345 kV voltage level and above and certain lower voltage facilities under specific conditions…Region-wide cost allocation via postage stamp rate for economic upgrades if part of a balanced portfolio of economic upgrades (vs. project by project assessment of benefit).

<u>Balanced Portfolio of Economic Upgrades</u>
- Balanced means a benefits/costs ratio >= 1.0, using adjusted production cost for determination of benefits.
- Adjusted Production Cost = Production Cost + Purchases - Sales
- Ten-year present value of zonal benefit should not be less than levelized revenue requirement via region-wide postage stamp rate.

<u>If a balanced portfolio of economic upgrades cannot be found…</u>
- Costs assigned to zones that are deficient in benefits removed from calculation of zonal rate and added to region-wide postage stamp rate to balance costs and benefits. Helps to equalize economic capability across SPP footprint without charging more highly developed portions of the system with the cost of upgrades for less developed portions. More costs can be collected through a region-wide rate, less via zonal license plate rates. If all zones are currently at the same level of development, SPP is likely to develop a balanced portfolio based solely on transmission upgrades and, thus, transfers are not likely to be needed to provide balance.
- Production cost savings offset transmission rates paid by load. Profits that would otherwise be captured as a result of increased sales vis-à-vis increased transmission rates are refunded/credited back to load.
- No customers in SPP's footprint have retail choice at this date, or in the foreseeable future. The Balanced Portfolio allows each pricing zone and each state to claim a positive benefit, a significant political point. No requirement for a Balanced Portfolio each year. In a given year, should the cost become too great or not enough projects found then the year is simply skipped. The policy decision on the balanced portfolio was determined by SPP’s Regional State Committee (RSC) through a stakeholder process</td></tr>
<tr><td></td><td></td><td></td></tr>
</table>

<table>
<tr><th rowspan="2">MISO</th><th colspan="2">MISO -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING</th><th>UNDER CONSIDERATION</th></tr>
<tr><td>Reliability Upgrades</td><td>▪ Baseline Reliability Projects (BRPs) >= 345 kV: 20% per Postage Stamp based on load ratio shares; remaining 80% based on Line outage Distribution Factor (LODF) calculation methodology used for sub-regional allocations.
▪ Baseline Reliability Projects of 100 kV to 344 kV: 100% of eligible cost is allocated to pricing zones based on LODF in terms of [LODF] x [Miles]. Sub-regional percentage share for a given pricing zone is calculated as the relative zonal share of sum of absolute values.
▪ Generation Interconnection Project cost of network upgrades:
- 50% based on the same sub-regional and/or postage stamp allocation rules applicable for BRPs; remaining 50% assigned to the Interconnection Customer
- Interconnecting to American Transmission Company, International Transmission Company, Michigan Electric or ITC Midwest pricing zones: 50% to pricing zone; 50% to affected pricing zones based on sub-regional and/or postage-stamp allocation rules
▪ Transmission Delivery Service Projects: needed for new Point-To-Point Transmission Service, or new Network Resource designation…assigned to transmission customer until appropriate regulatory authority permits roll-in to existing transmission rates
▪ PJM / MISO Cross-border: transfer distribution factor (DFAX) analysis to calculate impact of each RTO's flows on constraint, based on Total Net Flow.
- Total net flow of each RTO on a constraint = (all positive flow) less (all counterflow)
- After allocation to each RTO, each RTO then allocates according to its own OATT.</td><td>▪ [No modifications presently under consideration.]</td></tr>
<tr><td>Economic Upgrades</td><td>▪ "Regionally Beneficial Projects" (RBPs):
- 20% allocated on a system-wide rate to all transmission customers;
- 80% allocated to three defined sub-regions based on relative "weighted-gain-no-loss" value of positive present value of annual benefits…
  - 70% weighted on adjusted production cost changes
  - 30% on Locational Marginal Price (LMP) changes.
- "Cost" eligibility: >= $5 million
- "Voltage" threshold: >= 345 kV; and those under 345 kV needed to achieve benefit of associated upgrades over 345 kV
- "Benefit" Eligibility for regional cost allocation: (1) Present Value of annual benefits > 0; (2) minimum specified benefit/cost ratio met based on in-service date…
  - Within 1 year…1.2 : 1, Within 2 years 1.4 : 1
  - Within 3 years…1.6 :1, Within 4 years 1.8 : 1
  - Within 5 years…2.0 : 1, increasingly linearly up to 3.0 : 1 within 10 years</td><td>- "…as experience with [RBPs] and additional value driver analytics mature, tariff filings to adjust or amplify the inclusion criteria and minimum benefits threshold are expected…additional value drivers might include generation reserve margin considerations, fuel diversity considerations, reliability considerations and national and state energy policy goals, and risks to implementation to name some that warrant consideration."</td></tr>
</table>

<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.

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

NYISO	NYISO -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
	▪ **Regulated Reliability NON-TRANSMISSION Projects:** "Costs…will be recovered by [Transmission Owners] and other developers in accordance with the provisions of …state law." "Although the NY Public Service Commission has adopted a cost allocation mechanism that differs from the consensus methodology described [for TRANSMISSION, as above] it is the understanding of the NYISO and NY TOs that the [commission staff] does not object to the consensus methodology for transmission projects….and that the staff will present that methodology to the NY PSC…for their consideration and adoption for NON-TRANSMISSION regulated reliability projects "	
Economic Upgrades	▪ Current planning process includes a procedure for analysis and posting of historic congestion information to assist stakeholders in developing resource plans ▪ **NYISO Congestion Assessment and Resource Integration Study ("CARIS"):** - NYISO analyzes potential solutions to congestion over a 10-year period based upon requests for studies prioritized by NYISO stakeholders. Will consider all resources as potential solutions. Threshold based upon statewide production cost savings compared to total estimated project revenue requirement over ten years. NYISO will also calculate zonal locational marginal cost based savings, losses, transmission congestion contracts and other metrics. - Cost of regulated economic transmission projects allocated to load based on share of total LMP savings. 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.	▪ [No modifications presently under consideration.]

<table>
<tr><th rowspan="2">ISO-NE</th><th colspan="2">ISO-NE -- Cost Allocation Philosophies and Practices</th></tr>
<tr><th>EXISTING
[…on or after January 1, 2004, per ISO-NE Open Access Transmission Tariff]</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.

▪ RTUs: 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 RBUSs are not included in the Pool-Supported PTF Costs.
- By definition, neither METUs nor RBUs are “related to the interconnection of a generator,” unless determined otherwise under Schedule 11.</td><td>▪ [No modifications presently under consideration.]</td></tr>
</table>

ERCOT	ERCOT -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
Reliability Upgrades	▪ Costs allocated regionally to load and to power exports from ERCOT region, based on load-ratio share. ▪ Reliability upgrades include those to mitigate constraints both between and within established ERCOT sub-regions ▪ Specific transmission system improvements are evaluated for projected longer-term problems on the 345 kV network. ▪ Lines ordered as a result of the state's recently legislated Competitive Renewable Energy Zone (CREZ) process may supersede these projects.	▪ [No modifications presently under consideration.]
Economic Upgrades	▪ In addition to identified reliability upgrades, significant uneconomic congestion would be experienced if these were the only improvements and upgrades implemented. ERCOT also identifies congested system elements and evaluate upgrades that would be economic in reducing the energy production cost for the system by relieving these congested elements. - Costs for such upgrades are also allocated regionally to load and to power exports from ERCOT region based on load-ratio share. - Lines ordered as a result of the state's recently legislated Competitive Renewable Energy Zone (CREZ) process may supersede these projects.	▪ [No modifications presently under consideration.]

Cal-ISO	Cal-ISO -- Cost Allocation Philosophies and Practices	
	EXISTING	**UNDER CONSIDERATION**
Reliability Upgrades	▪ **For need as determined by the ISO** for the following types of proposed transmission additions or upgrades, cost is borne by each Participating TO and reflected in its Transmission Revenue Requirement: - Reliability driven projects - Economically driven projects - Long-term congestion revenue rights feasibility ▪ **Costs** recovered via Participating Transmission Owners (PTOs) revenue requirement through ISO administered charges; facilities at 200 kV and above: - Transmission Access Charge (TAC) -- paid by Load Serving Entities based on pro-rata load share. - Wheeling Access Charge (WAC) -- paid for transactions wheeled Out or Through ISO. ▪ **Location Constrained Resource Interconnection Facility (LCRIF)**… transmission projects to connect generators in designated transmission constrained areas; PTOs finance up-front costs; costs associated with the unsubscribed portion of the LCRIF will be included in TAC, until additional generators are interconnected, at which time costs will be assigned to such generators going forward on a pro-rata basis.	▪ [No modifications presently under consideration.]
Economic Upgrades	▪ **Economic Transmission Project proposals:** include upgrades or additions proposed to reduce Local Capacity Area Resource requirements, reduce or eliminate Congestion, or Merchant Transmission Facilities to obtain Merchant Transmission Congestion Revenue Rights. Costs are recovered per the process described above for reliability upgrades. ▪ **Merchant Transmission Facility:** a transmission addition or upgrade whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the TAC or WAC or other regulatory cost recovery mechanism. Rather than obtain a recovery of costs through a regulated rate, the Project Sponsor of the Merchant Transmission Facility obtains Merchant Congestion Revenue Rights	▪ [No modifications presently under consideration.]

12.2 References

An early 2008 update on the activities of the Northeast International Committee on Energy (NICE) can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/mar192008/a_nice_update.pdf, which provides an initial summary of proposed new resource development in New England and eastern Canada. The follow-up presentations made to the New England Governors and Eastern Canadian Premiers in September 2008 can be found at http://www.iso-ne.com/pubs/pubcomm/pres_spchs/index.html.

The Joint Coordinated System Plan (JCSP) is evaluating scenarios of large wind development primarily in the Midwest and transmission alternatives for delivery of the energy mostly to the Northeastern U.S. Materials can be found at http://jcspstudy.org/.

The New Brunswick System Operator (NBSO) has issued a report entitled: The Electric Power System in New Brunswick. A Discussion Paper on Potential Generation and Transmission Developments, December 2008, found at: http://www.nbso.ca/Public/_private/NBSO%20Discussion%20Paper%20Final%20Pre-release%20Dec%2012,%2020.pdf.

Information on the Northeast Power Coordinating Council (NPCC) can be found at: http://www.npcc.org/.

NPCC has also posted a report entitled "Modeling Wind Resources in Resource Adequacy Assessments," http://www.npcc.org/documents/publications/Other.aspx.

Information on ERAG can be found at the following links: http://www.erag.info, https://www.npcc.org/interReg/ERAG.aspx and https://www.npcc.org/interReg/reliabilityFirst.aspx.

The Inter-Area Planning Stakeholder Advisory Committee (IPSAC) is an open stakeholder group that supports the comprehensive interregional planning process implemented under the Northeastern ISO/RTO Planning Coordination Protocol ("Protocol") by ISO-NE, NYISO and PJM. The IPSAC has discussed the Northeast Coordinated System Plan including interregional projects and cost allocation issues.

Background IPSAC materials are posted on the public-domain IPSAC site: http://www.interiso.com/default.cfm.

For ISO-New England stakeholders:

Materials for the IPSAC meetings are posted on the password-protected IPSAC site: http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/index.html.

Access to the IPSAC is the same as for password-protected PAC materials. If you do not have access to the protected ISO-NE IPSAC site, please contact the ISO's Customer Service Department at (413) 540-4220 or custserv@iso-ne.com to request access.

For PJM stakeholders:

Materials for the IPSAC meetings are posted at: http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/ipsag.aspx.

For NYISO stakeholders:

Materials for the IPSAC meetings are posted at:
http://www.nyiso.com/public/committees/documents.jsp?com=oc_ipsac.

If you do not have access to the protected NYISO IPSAC site, please contact the NYISO Customer Service Department at (518) 356-6060 or http://www.nyiso.com/public/services/customer_relations/index.jsp.