

# **2013 Northeastern Coordinated System Plan**

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**ISO New England, New York ISO and PJM**

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## **Preface**

This report is a compilation of summaries of activities that have been completed or are currently ongoing with the Joint ISO/RTO Planning Committee (JIPC) during the years 2012 and 2013. The report also includes discussion of the Northeast Power Coordinating Council (NPCC), the ReliabilityFirst Corporation (RFC), and the North American Electric Reliability Corporation (NERC).

## 1 Executive Summary

ISO New England (ISO-NE), NYISO, and PJM participate in numerous national and interregional planning activities with the US Department of Energy (DOE), the Northeast Power Coordinating Council, and other balancing authority areas in the United States and Canada. The aim of these activities is to ensure the coordination of planning efforts for enhancing the widespread reliability of the interregional electric power system. NYISO, PJM and ISO-NE follow the Northeastern ISO/RTO Planning Coordination Protocol (Planning Protocol) to enhance the coordination of planning activities and address planning issues among the interregional balancing authority areas.<sup>1</sup>

To implement the protocol, the group formed the Joint ISO/RTO Planning Committee (JIPC) and the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) open stakeholder group.<sup>2</sup> Through the open stakeholder process, the JIPC addresses interregional issues, including discussion of system needs and proposed system improvements.

PJM, ISO-NE, and NYISO, through their interregional processes, must identify and resolve planning issues, as identified in needs assessments and solutions studies, consistent with the North American Electric Reliability Corporation (NERC) mandatory reliability requirements and other applicable reliability criteria.<sup>3</sup> These assessments include addressing and resolving potential interregional impacts. Interconnections with neighboring systems provide opportunities for the exchange of capacity and energy, and tie lines facilitate access to a diversity of resources and potential economic opportunities for energy exchange.<sup>4</sup> Identifying and quantifying potential mutual interregional benefits of system reinforcements and coordinating the planning of the interconnected system are becoming increasingly important.

ISO-NE, NYISO, and PJM proactively coordinate planning activities with neighboring ISO/RTO systems across the Eastern Interconnection through the Eastern Interconnection Planning Collaborative, and through participation and cooperation with the NERC. ISO-NE, NYISO and PJM work closely from time to time as necessary to conduct interregional reliability and production cost studies and coordinate interconnection and transmission studies. The three ISO/RTOs have continued to build on and evolve the interregional planning scope summarized in the 2011 *Northeast Coordinated System Plan*. The ISO/RTOs continue to evaluate interregional needs that

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<sup>1</sup> See existing [Planning Protocol](#). Hydro-Québec TransÉnergie, the Independent Electric System Operator of Ontario, and the Transmission & System Operator Division of New Brunswick Power participate in the Planning Protocol on a limited basis to share data and information.

<sup>2</sup> All IPSAC presentations, studies and other supporting material can be found on each ISO/RTO website: [PJM IPSAC materials](#); [ISO-NE IPSAC materials](#); [NYISO IPSAC materials](#).

<sup>3</sup> More information about NERC is available at <http://www.nerc.com/>. See also, [Northeast Power Coordinating Council \(NPCC\) Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System](#) (December 1, 2009); [ISO-NE Planning Procedure 3 – Reliability Standards for the New England Area Bulk Power Supply System](#) (March 1, 2013).

<sup>4</sup> At 12,614 GWh, ISO-NE's net interchange with neighboring systems totaled 9.9% of its net energy for load in 2012. Refer to [the New England 2013 Regional System Plan Load and Capacity Resource Overview](#), PAC presentation (April 24, 2013), slide 4; [NYISO's 2012 Comprehensive Reliability Plan](#) (Issued March 19, 2013); and according to [PJM Market Monitoring Report](#) (section 8), PJM net interchange with neighboring systems totaled less than 1% of its net energy for load in 2012 (PJM total load 790,090.3 GWh and net interchange 2770.9 GWh).

arise. These may include issues involving resource diversity, environmental compliance obligations, and resource retirements along with integrating distributed and variable energy resources. NCSP13 summarizes several of the planning issues being addressed by the ISO/RTOs. It also serves as a baseline for interregional planning as the planning process continues evolving to comply with FERC Order 1000.

Importantly, NCSP13 has been prepared pursuant to the provisions of the *existing* Planning Protocol. As described in the next section, PJM, NYISO and ISO-NE worked with their stakeholders (including through six separate meetings of the IPSAC) during 2012 and 2013 to develop and file with FERC an amended version of the Planning Protocol (Amended Planning Protocol) and other documents in response to the interregional requirements of FERC's Order 1000.<sup>5</sup> NYISO's, ISO-NE's and PJM's filings are currently under review by FERC; accordingly, the Amended Planning Protocol is not yet in effect.

## 2 Compliance with FERC Order 1000: Transmission Planning & Cost Allocation

FERC Order 1000, issued on July 21, 2011, provides additional requirements that build on Order 890, including regional and interregional planning procedures and cost allocation and the incorporation of "public policy considerations" into the planning process.<sup>6</sup> As noted above, NYISO, ISO-NE and PJM worked together and with their stakeholders during 2012 and 2013 to develop the Amended Planning Protocol to respond to the requirements of Order 1000. An overview of the high-level requirements of Order 1000 follows.

### 2.1 Regional Transmission Planning Requirements

While recognizing that ISO/RTOs typically already have regional planning provisions in their tariffs, Order 1000 required all jurisdictional transmission providers to make compliance filings. As in Order 890, the Commission declined to adopt a generic nationwide approach, but instead provided for regional flexibility.

Accordingly, Order 1000 specified additional regional planning requirements:

- The regional planning process must produce a "regional transmission plan"
- The regional planning process must evaluate alternative transmission solutions that might meet the needs of the region more efficiently or more cost-effectively than solutions developed in local transmission plans (LTPs)

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<sup>5</sup> See [Filing of Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on behalf of ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.](#), FERC Docket No. ER13-1957-000 (filed July 10, 2013). NYISO, PJM and ISO-NE also made separate filings of tariff/agreement changes to reflect compliance with interregional requirements of Order 1000.

<sup>6</sup> FERC, [Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000](#), 18 CFR Part 35, 136 FERC ¶ 61,051 (July 21, 2011) (Order 1000). See also [Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890](#), 18 CFR Parts 35 and 37, FERC Stats. And Regs. ¶ 31,241 (February 16, 2007), and [additional Order 1000 filings and materials](#).

- Non-transmission alternatives must be considered on a comparable basis with transmission
- If alternative transmission solutions are found to be more efficient or cost-effective than facilities identified in LTPs, those facilities can then be selected in the regional plan for regional cost allocation.

## **2.2 Public Policy Requirements**

Order 1000 required public utility transmission providers to amend their Open Access Transmission Tariffs (OATTs) to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements (i.e., those established by federal or state laws or regulations) in the local and regional transmission planning processes.

## **2.3 Participation by Non-incumbent Transmission Developers**

Order 1000 required removal of tariff provisions granting a federal right of first refusal (ROFR) for incumbent transmission owners to develop transmission projects to meet new transmission needs, so that non-incumbent transmission developers could offer solutions, as well. The removal of the ROFR is focused on the set of transmission facilities that are evaluated at the regional level and selected in the regional plan for purposes of cost allocation and does not apply:

- To a local transmission facility or an upgrade made by an incumbent to its own facilities; or
- To alter an incumbent transmission provider’s use and control of its existing ROWs.

To this end, Order 1000 requires the establishment of qualification criteria that transmission developers (whether incumbent or non-incumbent) must meet, the establishment of information requirements for a transmission project to be considered for inclusion in the regional plan, and a transparent project selection process.

## **2.4 Interregional Coordination Requirements**

Order 1000 required that each pair of neighboring transmission providers must include interregional coordination and cost allocation procedures in their respective tariffs. Cost allocation procedures are discussed in Section 2.5 below.

Specifically, Order 1000 required all transmission providers to develop further procedures with neighboring regions to provide for:

- (1) The sharing of information regarding the respective needs of each region, and potential solutions to those needs; and
- (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs.

The Commission emphasized the central importance of the regional planning processes, noting that interregional transmission coordination should complement local and regional transmission planning processes, and should not substitute for these processes.

Order 1000 requires development of specific interregional coordination procedures, including the development of a formal procedure to identify and jointly evaluate interregional transmission facilities that are proposed to be located in neighboring transmission planning regions. The

Commission also required the developer of an interregional transmission project to first propose its transmission project in the regional transmission planning processes of each of the neighboring regions in which the transmission facility is proposed to be located.

Further, the interregional evaluation must be conducted “in the same general timeframe” as each regional evaluation. Finally, in order for such project to receive cost allocation under the inter-regional cost allocation process, it must be selected in both of the regional planning processes.

While Order 1000 encouraged—but did not require—multi-lateral or interconnection-wide planning processes, ISO-NE, NYISO and PJM decided to leverage the existing agreements including the existing Planning Protocol, with appropriate modifications and accompanying tariff provisions for cost allocation, as their means for compliance with these requirements. The July 2013 filing of the Amended Planning Protocol, reflecting the efforts of the three regions, their stakeholders and the IPSAC, represents one element of the regions’ compliance with Order 1000’s interregional coordination requirements. Section 3 of the Amended Planning Protocol includes information and data sharing provisions and Section 7 addresses the identification and evaluation of potential interregional transmission projects.

## 2.5 Cost Allocation Requirements

For regional and interregional cost allocation, Order 1000 adopted a principles-based, rather than a “one-size-fits-all,” approach and recognized that regional differences may warrant different methods. Order 1000 required all transmission providers to demonstrate compliance with six cost allocation principles—with variants for both regional and interregional cost allocation:<sup>7</sup>

Principle #1: Costs are to be allocated roughly commensurate with benefits.

Principle #2: There must be no involuntary allocation of costs to those who do not benefit. A region that receives no benefit from an interregional transmission facility located in that region must be allocated no costs for that facility.

Principle #3: A benefit-cost threshold, if one is used, must not exceed 1.25. A benefit-cost threshold is not required, however.

Principle #4: Allocation of costs for a transmission project must be to those solely within a transmission planning region or regions, unless those outside that region or regions voluntarily agree to bear such costs.<sup>8</sup>

Principle #5: The cost allocation methodology must be transparent with respect to determining benefits and the identification of beneficiaries.

Principle #6: Different cost allocation methodologies may be used for different types of transmission facilities (e.g. – reliability, economic and public policy).

With respect to inter-regional cost allocation, FERC determined that:

<sup>7</sup> See generally [Order 1000](#) at ¶¶ 612-685.

<sup>8</sup> The Order provides an example to illustrate the application of this principle to an interregional facility: “For example, if regions A & B plan an interregional transmission facility that they believe benefits region C, regions A and B cannot allocate costs of that facility to region C involuntarily.” Order 1000 at fn. 499.

- The inter-regional cost allocation method agreed to by two regions may be different from their respective regional cost allocation methodologies; and
- The method to allocate a region's share of the costs for an inter-regional facility may differ from the method used to allocate the costs of a regional facility.

The transmission owners in ISO-NE, PJM and NYISO worked together in 2013, with input from stakeholders, to develop and file with FERC default cost allocation methodologies for interregional projects spanning PJM and NYISO, and spanning NYISO and ISO-NE.<sup>9</sup> These filings are pending FERC consideration.

### 3 Summary of ISO/RTO System Plans

The ISO/RTO system plans identify system needs and plans for meeting those needs in accordance with their respective OATTs. PJM, NYISO, and ISO-NE coordinate these short- and long-term system needs and plans with neighboring systems to identify opportunities for interregional system improvements. This section summarizes the respective ISO/RTO documents that summarize the respective ISO/RTO system plans. Stakeholders, including developers of resources and transmission facilities, can use this summary and the references it contains to the full reports.

#### 3.1 PJM 2013 Regional Transmission Expansion Plan

##### 3.1.1 Reliability

The PJM Regional Transmission Expansion Plan (RTEP) is published annually in February. The 2013 RTEP describes analysis performed over a range of study years and system conditions, including studies of a 2018 summer peak model. The load forecast represents all transmission owners in the PJM system as of January 1, 2013, which includes a weather normalized unrestricted summer peak demand forecast. The annual load growth rate is 1.3% over the next 10 years, growing from 155,553 MW in 2013 to 177,439 MW in 2023. This is an increase of 21,886 MW over the decade. This forecast represents the projection of "unrestricted" peak load growth based on a PJM "entity" forecast that reflects the diversity of the peaks of the individual zones.<sup>10</sup> Individual geographic zone growth rates vary from 0.5% to 1.9%. Energy Efficiency and Demand Response are accounted for separately and appropriately factored into the various planning analyses. A new load forecast that will be used in the upcoming 2014 planning cycle was released in January of 2014. This report shows the annual load growth rate is 1.0% over the next 10 years, growing from 157,399 MW in 2014 to 173,852 MW in 2024. This is an increase of 16,453 MW over the decade

In developing the RTEP, PJM performs comprehensive power flow, short circuit, stability, and market efficiency analyses. These studies assess the impacts of firm load forecasts and transactions

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<sup>9</sup> See the pertinent portions of the July 10, 2013 filings in FERC Docket Nos. ER13-1926 (PJM transmission owners), ER13-1942 (NYISO transmission owners) and ER13-1960 (ISO-NE transmission owners). The respective interregional cost allocation provisions are cross-referenced in Section 9 of the Amended Planning Protocol. Regional cost allocation provisions were included in prior filings.

<sup>10</sup> Unrestricted peak load means peak load prior to any reduction for load management, accelerated energy efficiency or voltage reduction.

with neighboring systems, existing generation and transmission assets, anticipated retired and new generation, and transmission facility improvements.

Since the inception in 1997 of PJM's RTEP process, through December 31, 2013, the PJM Board has approved nearly \$29 billion of Bulk Electric System (BES) transmission enhancements, ensuring that PJM is compliant with NERC reliability criteria. This includes nearly \$21 billion of baseline transmission upgrades across PJM. It also includes nearly \$8 billion of additional BES transmission upgrades that enable the interconnection of over 51,000 MW of new generating resources and 5,000 MW of merchant transmission capability.

The 2013 RTEP studies included all previously approved PJM backbone transmission projects, including the 2007 approved Susquehanna-Lackawanna-Hopatcong-Roseland 500 kV circuit and the 2011 approved reconductoring of the Cloverdale-Lexington 500 kV circuit. Recently approved backbone projects are the Doooms-Lexington 500 kV line, rebuild of the Mount Storm-Doubs 500 kV line, the Surry-Skiffes Creek 500 kV line, the Loudoun-Brambleton 500 kV line, and the Vassell 765 kV substation. In addition to the backbone projects, the 500 kV Jacks Mountain dynamic reactive project in western Pennsylvania and many other upgrades across PJM are discussed in more detail in the 2013 RTEP and on the Planning/RTEP pages of the PJM website.<sup>11</sup> All PJM backbone projects continue to be evaluated annually and as changing system conditions warrant.

PJM continuously addresses the need for improvements to planning processes based on its own initiative as well as comments and suggestions by stakeholders. These on-going efforts include the recent federal requirements of Order 1000. During 2014, PJM will be implementing significant enhancements to the PJM planning process and considering further enhancements. These include how to improve planning under conditions involving uncertain and changing assumptions, how to address public policy interactions, and how to address projects that potentially satisfy multiple drivers. Enhancements to the inter-regional requirements of Order 1000 are pending in a filing with FERC.

### 3.1.2 Market Efficiency

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

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<sup>11</sup> PJM RTEP upgrades are located at: <http://www.pjm.com/planning/rtep-upgrades-status.aspx>.

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

Project benefits include recognition of a project's energy market benefit including production costs and load energy payments. The starting assumptions and results of PJM's 2013 market efficiency analysis<sup>12</sup> are available at [PJM RTEP report](#). The 2013 edition of this analysis produced projects with impacts limited to the PJM region.

### 3.1.3 Public Policy

Over the past several years, an increasing focus by federal and state governments on environmental and other policy areas continues to make clear the critical role of the PJM transmission system. And, while NERC reliability criteria violations remain PJM's principal basis under the RTEP protocol for justifying transmission expansion, construction of significant transmission infrastructure could be required to support the achievement of public policy goals. These policies range from promoting renewable generating resources (such as wind and solar), demand resource and energy efficiency programs, to environmental compliance that will affect PJM's coal-fired generating fleet. Whether taken individually, or collectively, public policy decisions have begun to drive transmission planning decisions. To that end, during 2013, both scenario studies and interregional studies examined the growing impacts of coal-fired generation deactivation and the influx of renewable-powered generation to meet state RPS targets.<sup>13</sup>

## 3.2 NYISO 2012 Comprehensive Reliability Plan (March 2013) and CARIS (Fall 2013)

### *NYISO 2012 Comprehensive Reliability Plan*

The 2012 Reliability Needs Assessment (RNA) provides a long-range reliability assessment of both resource adequacy and transmission security of the New York bulk power system conducted over a ten-year Study Period (2013 – 2022).<sup>14</sup> This RNA identified Reliability Needs beginning in 2013 based on transmission security needs, and by 2020 based on resource adequacy needs. Therefore, the 2012 Comprehensive Reliability Plan (CRP), published March 19, 2013, analyzed market-based, regulated backstop, and alternative regulated solutions to the identified Reliability Needs:

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<sup>12</sup> Book 2, Section 5 of PJM RTEP report: <http://www.pjm.com/documents/reports/rtep-documents/2013-rtep.aspx>.

<sup>13</sup> Book 2, Section 6 of PJM RTEP report: <http://www.pjm.com/documents/reports/rtep-documents/2013-rtep.aspx>.

<sup>14</sup> NYISO [2012 Reliability Needs Assessment Final Report](#) (September 18, 2012).

1. Transmission Security – The NYISO identified potential transmission security violations on the BPTF (bulk power transmission facilities) throughout the study period. Some violations occur as early as 2013 as the result of the additions made in late 2010 to the NYISO’s BPTF list rather than due to any significant system changes since the 2010 RNA. The NYISO designated certain Transmission Owners (TOs) responsible for developing regulated backstop solutions to address the Reliability Needs identified in the RNA. As part of their planning responsibilities, the TOs updated their Local Transmission Plans (LTPs) as necessary and also submitted regulated backstop solutions to meet the identified Reliability Needs over the ten-year period (2013 – 2022). Based upon the TO LTPs and proposed specific operating instructions for certain needs, the NYISO concluded that there are sufficient solutions to mitigate the transmission security issues identified as Reliability Needs in 2013.
2. Resource Adequacy – The 2012 RNA reported that the forecasted system first exceeds the Loss of Load Expectation (LOLE) criterion in the year 2020, and again in years 2021 and 2022. The 2012 CRP found that the need year for new resources is 2019 based upon the unexpected retirement of the Danskammer generating facility, which was damaged in Superstorm Sandy. The Reliability Needs identified in these years are resource adequacy deficiencies in Zones G – K. The need could be resolved by adding capacity resources downstream of the transmission constraints or by transmission reinforcement. A market-based solution capable of fully meeting the resource adequacy need was accepted. The NYISO will continue to monitor, evaluate and report, on a quarterly basis, the viability and timeliness of all submitted market-based solutions and will be prepared to trigger a gap or regulated backstop solution, if necessary.

### *NYISO Economic Studies*

Pursuant to Attachment Y of OATT, the NYISO performed the first phase of the 2013 Congestion Assessment and Resource Integration Study (CARIS).<sup>15</sup> The study assesses both historic and projected congestion on the New York bulk power system and estimates the economic benefits of relieving congestion. Together with the Local Transmission Planning Process (LTPP) and the Comprehensive Reliability Planning Process (CRPP), CARIS is the final process in the NYISO’s current biennial Comprehensive System Planning Process (CSPP). The 2013 CARIS completes the CSPP process that began with LTPP inputs for the 2012 Reliability Needs Assessment.

CARIS consists of two phases: Phase 1 (the Study Phase), and Phase 2 (the Project Phase). Phase 1 is initiated after the NYISO Board of Directors (Board) approves the Comprehensive Reliability Plan (CRP). In Phase 1, the NYISO, in collaboration with its stakeholders and other interested parties, develops a ten-year projection of congestion and together with historic congestion identifies, ranks, and groups the most congested elements on the New York bulk power system. For the top three congested elements or groupings, studies are performed which include: (a) the development of three types of generic solutions to mitigate the identified congestion; (b) a benefit/cost assessment

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<sup>15</sup> NYISO, [2013 Congestion Assessment and Resource Integration Study](#) (November 19, 2013).

of each solution based on projected New York Control Area (NYCA)-wide production cost savings and estimated project costs; and (c) presentation of additional metrics for informational purposes. The four types of generic solutions are transmission, generation, energy efficiency, and demand response. Scenario analyses are also performed to help identify factors that increase, decrease or produce congestion in the CARIS base case.

Developers may propose economic transmission projects for regulated cost recovery under the NYISO's Tariff and proceed through the Project Phase, CARIS Phase 2, which will be conducted by the NYISO upon request and payment by a developer. Developers of all other projects can request that the NYISO conduct an additional CARIS analysis at the Developer's cost to be used for the Developer's purposes, including for use in a New York State Public Service Commission (NYS PSC) Article VII, Article X or other regulatory proceedings. For a transmission project, the NYISO will determine whether it qualifies for regulated cost recovery under the Tariff. Under CARIS, to be eligible for regulated cost recovery, an economic transmission project must have production cost savings greater than the project cost (expressed as having a benefit to cost ratio (B/C) greater than 1.0), a cost of at least \$25 million, and be approved by at least 80% of the weighted vote cast by New York's Load Serving Entities (LSEs) that serve loads in Load Zones that the NYISO identifies as beneficiaries of the transmission project. The beneficiaries are those Load Zones that experience net benefits measured over the first ten years from the proposed project commercial operation date. After the necessary approvals, regulated economic transmission projects are eligible to receive cost recovery from these beneficiaries through the NYISO Tariff provisions once they are placed in service.

The 2013 CARIS Phase 1 report presents an assessment of historic (2008 – 2012), and projected (2013 – 2022) congestion on the New York State bulk power transmission system, and provides an analysis of the potential costs and benefits of relieving that congestion using generic projects as solutions.<sup>16</sup> Consistent with the CARIS procedures, the NYISO ranked and grouped transmission elements with the largest production cost savings when congestion on that constraint was relieved. Based on the top three groupings, three studies were selected: Central East – New Scotland – Pleasant Valley (Study 1), Central East (Study 2), and New Scotland – Pleasant Valley (Study 3). The present value of the estimated carrying costs for each of the generic solutions was compared to the present value of projected production cost savings for a ten-year period, yielding a benefit/cost ratio for each generic solution. The NYISO also conducted scenario analyses to evaluate the congestion impact of changing variables in the base case assumptions. The scenarios were selected by the NYISO in collaboration with its stakeholders. The base case was modified to address potential regulatory changes in environmental emission requirements, full achievement of the State Renewable Portfolio Standard and the State Energy Efficiency Portfolio Standard, variations from the forecasted energy consumption and fuel prices, and the termination of the Athens Special Protection System (SPS) for the Study Period.

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<sup>16</sup> NYISO [2013 Congestion Assessment and Resource Integration Study](#) (November 19, 2013).

### Public Policy

The objectives of the NYISO's Public Policy Transmission Planning Process are to:

- (1) Allow Market Participants and other interested parties to propose transmission needs that they believe are being driven by Public Policy Requirements and for which transmission solutions should be evaluated,
- (2) Provide a process by which the New York State Department of Public Service (NYSDPS) and NYSPSC will, with input from the ISO, Market Participants, and other interested parties, identify the transmission needs, if any, for which transmission solutions should be evaluated,
- (3) Provide a process whereby all solutions to Public Policy Transmission Needs are proposed and evaluated on a comparable basis,
- (4) Provide a process by which the ISO will select the more efficient or cost effective regulated transmission solution, if any, to satisfy the Public Policy Transmission Need for eligibility for cost allocation under the ISO Tariffs;
- (5) Provide a cost allocation methodology or regulated transmission projects that have been selected by the ISO, and
- (6) Coordinate the ISO's Public Policy Transmission Planning Process with neighboring Control Areas.

The NYISO's Public Policy Transmission Planning Process begins with the NYISO's request for transmission needs being driven by Public Policy Requirements. The NYDPS reviews all proposed transmission needs being driven by Public Policy Requirements and identifies the transmission needs for which specific transmission solutions should be requested and evaluated. The NYISO will evaluate on a comparable basis the viability and sufficiency of all proposed solutions whether transmission or non-transmission, to determine whether each solution will satisfy an identified Public Policy Transmission Need and will include the results of its evaluation in the Public Policy Transmission Planning Report. The NYISO will then evaluate all of the proposed regulated transmission solutions that have been found to be viable and sufficient and may select for cost allocation purposes the more efficient or cost-effective transmission solution among the proposed transmission solutions offered to satisfy an identified Public Policy Transmission Need.

The NYISO's Public Policy Transmission Planning Process will be conducted in a two-year cycle and will be conducted in parallel with the NYISO's reliability and economic planning process. The NYISO is beginning implementation of this new process in 2014.

### 3.3 ISO New England 2013 Regional System Plan (November 2013)

ISO New England Inc., the operator of the regional power system and wholesale electricity markets, released the *2013 Regional System Plan* (RSP13), a comprehensive report that outlines transmission

upgrades and market responses, such as generation or demand response, that can address identified power grid reliability needs.<sup>17</sup>

The RSP is the culmination of a year-long process with industry representatives and other stakeholders to analyze power system needs and solutions over a 10-year planning horizon. RSP13 also discusses areas of concern that the ISO and regional stakeholders have identified through the Strategic Planning Initiative and reviews the possible effects of state and federal policies on the New England grid.<sup>18</sup>

### *Transmission and power system planning*

From 2002 through June 2013, 475 transmission projects, a \$5.5 billion investment in new infrastructure, addressing reliability needs were put into service in all six New England states.

Additional transmission upgrades to meet reliability requirements are being designed, have been approved or are under construction. Some of the larger projects underway include the New England East-West Solution (NEEWS), which comprises major transmission upgrades in Massachusetts, Connecticut, and Rhode Island; the Maine Power Reliability Program; and transmission system upgrades in southeastern Massachusetts and the Greater Boston area. Approximately \$5.7 billion in transmission investment for reliability purposes is planned for the next five years.

### *Capacity*

Since 1997, nearly 14,900 megawatts (MW) of new generation have been constructed in New England, while approximately 3,360 MW of less efficient, primarily older resources, have retired. Currently, about 1,850 MW of demand resources (both demand-response and energy-efficiency measures) are part of New England's resource mix.

The seventh Forward Capacity Market auction (FCA #7) procured adequate resources to meet demand through 2016/2017.<sup>19</sup>

### *Long-term load forecast*

Energy consumption, unadjusted for energy-efficiency (EE) programs, is projected to grow an average of 1.1% annually through 2022, while summer peak demand is expected to grow by 1.4% per year. Because of the increased investment in EE programs sponsored by the New England states, ISO-NE developed the first multistate EE forecast methodology. When the energy-saving effects of EE are included, the forecast shows essentially no long-run growth in electric energy use and 0.9% annual growth in annual summer peak demand.

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<sup>17</sup> [ISO-NE 2013 Regional System Plan](#) (November 8, 2013). The ISO-NE board of directors approved the annual plan on November 7, 2013.

<sup>18</sup> ISO-NE, *Strategic Planning Initiative* materials including discussion memos, white papers, and study reports can be found on the ISO website under [www.iso-ne.com/spi](http://www.iso-ne.com/spi).

<sup>19</sup> ISO-NE, [2016-2017 Forward Capacity Market Auction](#) (February 27, 2013). Includes FCA 2016-2017 MW obligations, DR type, resource location and qualification values for FCA#7.

### Strategic Planning Initiative

In 2010, ISO-NE launched the Strategic Planning initiative to identify risks that could compromise the efficiency and reliability of the power grid.<sup>20</sup> The predominant reliability challenges include the region's reliance on natural gas for power generation, the potential retirements of older fossil-fuel-fired generation, and the interconnection of increasing levels of renewable resources. Changes to operating procedures and market rules are underway to address these challenges and include the following measures:

- **Day-Ahead Energy Market time shift** (implemented): More closely aligns the timelines of the Day-Ahead Energy Market and natural gas trading day, giving generators more time to make fuel and transportation arrangements and giving ISO system operators more time to commit long-lead-time generators when needed.<sup>21</sup>
- **Tightening the shortage-event trigger** (implemented): The definition of a "shortage event" was modified to more accurately reflect stressed system conditions.<sup>22</sup>
- **Winter reliability program** (approved by FERC; implementation December 1, 2013): An interim, stopgap solution to help ensure power system reliability in the event of colder-than-normal weather during the 2013/2014 winter.<sup>23</sup>
- **Energy market supply offer flexibility** (approved by FERC; implementation December 2014): Will allow generators to change their power supply offers during the operating day to reflect changes in actual fuel prices, helping generators better adjust to short-term fuel arrangements or high, real-time fuel prices.<sup>24</sup>
- **FCM Performance Initiatives** (FERC filing made January 2014): Proposal for a more robust incentive structure that would reward resources that over perform during times of system stress by transferring payments from resources that underperform during these periods.<sup>25</sup>
- **Operating Reserves** (operational change implemented): The ISO increased the 10-minute operating-reserve requirement by 25% to address its concern about the performance of resources and ensure the region has adequate reserves available to recover from unplanned outages.

### New England's fuel mix

In 2012, 52% of the electricity generated in the region was produced by natural-gas-fired power plants, while oil units produced less than 1%, and coal plants generated about 3%. Nuclear produced

<sup>20</sup> ISO-NE, *Strategic Planning Initiative* materials including discussion memos, white papers, and study reports can be found on the ISO website under [www.iso-ne.com/spi](http://www.iso-ne.com/spi).

<sup>21</sup> FERC, [Order Accepting NEPOOL Version of Day-Ahead Market Revisions](#), 143 FERC ¶ 61,065 (April 24, 2013).

<sup>22</sup> FERC, [Order On Proposed Tariff Revisions](#), 145 FERC ¶ 61,095 (November 1, 2013). For additional information on shortage events see ISO-NE, [Shortage Event Definition changes](#).

<sup>23</sup> FERC, [Order Conditionally Accepting Tariff Revisions](#), 144 FERC ¶ 61,204 (September 16, 2013). For additional information see ISO-NE, [2013-2014 Winter Reliability program](#).

<sup>24</sup> FERC, [Order Conditionally Accepting Tariff Revisions](#), 145 FERC ¶ 61,014 (October 3, 2013), requiring ISO-NE to adopt by January 17, 2014 tariff provisions implementing the offer flexibility changes in the day-ahead and real-time markets, ISO-NE, [Compliance Filing re Energy Market Offer Flexibility Changes](#), ER13-1877-001 (January 17, 2014).

<sup>25</sup> ISO-NE and New England Power Pool, Filings of Performance Incentives Market Rule Changes, Docket No. ER14-\_\_\_-000 (January 14, 2014).

approximately 31%; hydro and pumped storage produced 7%; and renewable energy resources produced 7% of the electricity generated in the region.<sup>26</sup> Net imports into the region reached 9.9% of net energy for load in 2012.<sup>27</sup> The region remains alert to potential retirements and is working with stakeholders on market rule revisions to the Forward Capacity Market.

### *Ongoing wind integration efforts*

As the amount of wind power in New England continues to grow, the ISO implemented a wind power forecast for use in daily system operations beginning in January 2014.<sup>28</sup> Progress continues on other recommendations from the New England Wind Integration Study, including modifying operating procedures and data requirements for wind resources and, over the longer term, integrating wind resources into ISO scheduling and dispatch services.<sup>29</sup> The ISO is also considering changes to its generator interconnection study process, including analyzing a wider range of operating conditions than are currently required, as well as identifying elective upgrades to the transmission system in the remote areas where most wind projects are built.

### *Growth in solar power and other distributed generation*

Distributed generation (DG) resources—primarily solar photovoltaic (PV) facilities, but also cogeneration and small-scale biomass and wind turbines—are rapidly expanding in New England. State policies are encouraging the development of these resources, most of which are connected to the distribution system and therefore are not visible to ISO system operators. It is anticipated that more than 2,000 MW of DG, mostly PV resources, will be installed regionwide by the end of 2021, up from about 250 MW of PV at the end of 2012. To address the potential effects of high levels of DG on grid reliability, the ISO recently convened a Distributed Generation Forecast Working Group. This group will gather information about DG resources in New England and eventually develop a forecast of future DG growth to be incorporated into the long-term planning process.<sup>30</sup>

### *Smart grid advancement*

The New England region is committed to advancing technologies that improve the reliable and economic performance of the system. For example, in June, ISO New England, in partnership with several New England transmission owners, completed installation of 40 phasor measurement units (PMUs, or synchrophasors) on the high-voltage transmission system throughout New England. These synchrophasors are now streaming data to the ISO and transmission owners, which are using

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<sup>26</sup> 2013 electric generation data will be available in the ISO-NE 2014 Capacity, Energy, Loads, and Transmission (CELT) Forecast Report, in May 2014. Earlier ISO-NE CELT reports are available at <http://www.iso-ne.com/trans/celt/report/>.

<sup>27</sup> ISO-NE, *Net Energy and Peak Load by Source* (accessed April 8, 2014). In 2012, net energy for load in New England: 128,081 GWh. 2012 Generation: 116,942 GWh. During 2012, in New England, net flow over external ties were -12,648 GWh (imports -18,025 GWh, exports 5,377 GWh). Breakdown of net flow over external ties: New Brunswick -643 GWh; Hydro-Quebec -13,077 GWh; New York 1,073 GWh (For external ties: imports are negative, exports are positive).

<sup>28</sup> ISO-NE, *Seven Day Wind Power Forecast*. Aggregate wind power forecast for each hour (by hour ending) for the next seven days. Forecast is updated daily, generally by 10:00 a.m. ET.

<sup>29</sup> ISO-NE, *New England Wind Integration Study Final Report* (December 17, 2010)

<sup>30</sup> ISO-NE, *Distributed Generation Forecast Working Group*.

the data to analyze system disturbances and to develop tools for system operators. The project was funded by a 2009 grant from the US Department of Energy.

### *The Role of Planning in New England*

The annual *Regional System Plan* is developed to meet requirements established by the FERC, NERC, and the NPCC. Each RSP is a snapshot of the power system and relevant studies and forecasts at a point in time, and the results are revisited as needed to incorporate the latest available information. ISO New England produces the RSP according to the requirements of Attachment K of the OATT.<sup>31</sup>

#### **3.3.1 ISO-NE Economic Studies**

Economic studies of various system-expansion scenarios have used metrics such as potential production costs, transmission congestion, and a number of others to suggest the most economical locations for resource development and the least economical locations for resource retirements. Other economic studies are showing the effects of possible new imports from Canada.

Both the 2011 and 2012 economic studies analyzed several of the strategic issues the region is addressing.<sup>32</sup> The 2011 economic study examined the effects of integrating varying amounts of wind on production costs, load-serving energy expenses, and emissions, as well as the need for transmission development, to enable wind resources to serve the region's load centers. The 2012 Economic Study highlighted the least suitable locations for unit retirements and the most suitable locations for developing different resources without causing congestion. The study showed the effects of using various amounts of energy efficiency and low-emitting resources, including renewable energy.

These studies showed several key results. Accessing the onshore wind energy located in northern New England remote from load centers will require transmission expansion. Replacing older high-emitting coal- and oil-fired units with cleaner-burning natural gas generation will decrease environmental emissions but increase New England's dependence on natural gas and potentially require the expansion of the natural gas system infrastructure. The addition of resources with low energy costs decreases electric energy expenses for LSEs but also decreases energy market revenues to resources, which may then require increases in other revenue sources to remain economically viable.

The ISO is currently conducting an economic study in response to a stakeholder request received in 2013. This study, expected complete by late 2014, will examine the effects of increasing the acceptable loss-of-source limits in New England. As with other economic studies, the results will show changes in the production of electric energy by different types of generators using various types of fuels.

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<sup>31</sup> ISO-NE, [Open Access Transmission Tariff](#) (January 1, 2013).

<sup>32</sup> ISO-NE, [2012 Economic Study – Final Draft Report](#) (January 21, 2014), and [2011 Economic Study – Final Draft Report](#) (January 6, 2014).

### 3.3.2 Planning for Policy

RSP discusses the effects that policies have on the power system and how the region is addressing many of those issues through the Strategic Planning Initiative and related studies of fuel diversity, resource retirements, variable resource integration and projecting distributed generation, and smart grid. ISO New England will be under obligation to more proactively plan for policy in accordance with Order 1000, but has yet to receive a final FERC order.

## 4 Interregional Studies and Planning Activities Supporting the Planning Protocol

As noted above, ISO-NE, NYISO, and PJM follow a Planning Protocol to enhance the coordination of planning activities and address planning issues among the interregional balancing authority areas.<sup>33</sup> Hydro-Québec TransÉnergie, the Independent Electric System Operator of Ontario, and the Transmission & System Operator Division of New Brunswick Power participate on a limited basis to share data and information. The key elements of the Planning 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
- 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 the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) open stakeholder group.<sup>34</sup> Through the open stakeholder process, the JIPC has addressed several interregional, balancing-authority-area issues. System needs and proposed improvements have been discussed on a regular basis.

### 4.1 Coordination of Transmission Projects with Potential Interregional Impacts

The ISO/RTOs assess the interregional impacts of their system needs and coordinate projects that could affect the interregional performance of the overall system. This includes reliability projects, economic projects, and system interconnection projects that are planned by the respective regions.

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<sup>33</sup> The Northeastern ISO/RTO Planning protocol available at: [NYISO Northeast Planning Protocol](#); [ISO-NE Northeast Planning Protocol](#); and, [PJM Northeast Planning Protocol](#).

<sup>34</sup> All IPSAC materials are available at [http://www.iso-ne.com/committees/comm\\_wkgrps/othr/ipsac/index.html](http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/index.html).

#### 4.1.1 Baseline Reliability Projects

##### *ISO New England Projects*

ISO New England needs and major ISO projects have been coordinated through the JIPC to determine potential interregional impacts. For example, the Maine Power Reliability Program (MPRP), the New England East-West Solution (NEEWS), and the Long-Term Lower Southeastern Massachusetts (Lower SEMA) have been discussed. The need for these projects could not realistically be met with interconnections to neighboring systems and these projects have been shown to have no adverse impact on neighboring systems.

##### *NYISO Projects*

###### *Moses – Willis Double Circuit Separation*

Contingencies existed on the New York Power Authority (NYPA) 230 kV system that limited New York's ability to serve local load and to move power to New England. Although system upgrades eliminated these contingencies and improved reliability of service to New York, NYISO has recommended against relying on flow into Vermont across the existing Plattsburgh to Vermont tie (PV-20).<sup>35</sup> Furthermore, no additional contracts are in place across the facility to ensure that power would flow to New England as needed.

##### *PJM Projects*

###### *PJM Northern NJ Short Circuit issues*

The PJM 2012 RTEP process raised and investigated Northern New Jersey short circuit issues. These were subsequently verified in 2013 analyses. These analyses identified short circuit reliability criteria violations at several substations in the northern part of the PSE&G system that will be near or exceed their 80 kA ratings beginning in 2015. The combined impacts of a tightly networked system, existing generation, and new generation additions together with required RTEP transmission projects will drive short circuit breaker duties above their 80 kA ratings at several 230 kV stations: Essex, Kearney and New Jersey Transit Meadowlands (NJT Meadows). Those violations have required the development of upgrade solutions to mitigate fault duty currents in excess of standard, conventional industry-available circuit breaker capabilities. Notably, just as 2012 initial results had revealed, 2013 short circuit analyses revealed that in addition to the fault current contributions from generators on the PSE&G system, the two 345 kV tie lines connecting PSE&G's Hudson substation to Consolidated Edison's Farragut substation also contribute to short circuit duties at Hudson, Kearney and Essex. Those results provided the basis for developing the Hudson / Farragut HVDC alternative initially proposed to the PJM Board and driving the need for interregional consideration.

This DC option encompassed conversion of the existing Phase Angle Regulator (PAR) control on the Hudson – Farragut 345 kV tie lines to control by a High Voltage Direct Current facility (HVDC). In

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<sup>35</sup> NYISO and NYPA have informed ISO New England that in 2013 the Moses-Willis 230 kV double-circuit towers in northern New York will be separated.

order to assess the potential impacts of such conversion, PJM performed both an internal analysis and a cross-border impact analysis with the input of NYISO. While the HVDC alternative was not selected, PJM completed interregional studies with input from NYISO and ISO New England to study any potential reliability impacts to enable the consideration of the HVDC alternative compared to other options.

PJM performed three types of studies: linear transfer analysis, power-voltage transfer analysis, and contingency analysis using information provided by both NYISO and ISO New England. The study results are described in Book 2, section 6 of PJM RTEP report.<sup>36</sup> Ultimately, a PJM 138 kV to 345 kV conversion project involving only PJM internal upgrades was presented to the PJM board and approved and is expected in-service by 2018. PJM is currently reviewing and ensuring appropriate interim measures are in place if needed for the period between the expected onset of the short circuit issues in 2015 and the full operation of the planned upgrades.<sup>37</sup>

#### PJM Homer City Lines Substations

PJM specified two upgrade projects in the Northern Mid-Atlantic area to address local reliability issues. The scope of the two upgrades requires cutting-in new substations on the Homer City – Stolle Road 345 kV and Homer City – Watercure 345 kV lines. Both are tie lines to the NYISO and owned by New York State Electric & Gas Corporation (NYSEG). PJM initiated efforts in 2012 to perform the necessary studies to identify any cross-border impacts with NYISO. The NYISO/NYSEG System Impact Study of Farmers Valley (NYISO Q#390) and Mainesburg (NYISO Q#394) is underway and currently scheduled to be completed in mid-2014. The initial study results received by PJM thus far have not indicated a need for upgrades to the New York Transmission System. These projects are proceeding to the construction phase.

#### 4.1.2 Status of Planned Interconnections between the ISO/RTOs

A tie between Plattsburgh, NY, and VT is proposed as an elective transmission upgrade. NYISO and ISO-NE are coordinating the interconnection studies.

#### 4.1.3 Queue Projects with Potential Interregional Impacts

##### Interconnection of Cricket Valley (CVEC)

The Cricket Valley Energy Center project is a 1,020 MW natural gas-fired electric generating facility to be located in Dover, NY adjacent to Consolidated Edison's right-of-way for the 345 kV Line 398 (*i.e.*, Pleasant Valley to Long Mountain 345 kV Line 398).<sup>38</sup> As part of the project the following System Upgrade Facilities (SUFs) will also be built: 1) a new Cricket Valley to Pleasant Valley 345 kV line, parallel to the existing Line 398, to be owned by Consolidated Edison; and 2) reconductoring of the existing Long Mountain to Cricket Valley segment of Line 398 (part of the segment is owned by Consolidated Edison, part of the segment is owned by Northeast Utility). This

<sup>36</sup> Book 2, section 6 of PJM RTEP report : <http://www.pjm.com/documents/reports/rtep-documents/2013-rtep.aspx>

<sup>37</sup> PJM's 2013 RTEP Plan is available online at: <http://www.pjm.com/documents/reports/rtep-report.aspx>.

<sup>38</sup> A 3-train combined cycle (3 -1x1) configuration, with each train consisting of two electric generators: a combustion turbine generator (CTG) and a steam turbine generator (STG).

project is proposed by Cricket Valley Energy Center, LLC, and is currently undergoing Class Year 2012 Interconnection Process Facilities Study.

Because the project is a proposed interconnection to a New York (NY)-New England (NE) tie-line, additional studies and coordination with ISO New England and the affected NE transmission owners were required in order to evaluate and address the reliability impacts of the Cricket Valley project on the NE as well as NY systems. The result of this coordination was the identification of the need for a second Pleasant Valley to Cricket Valley line, and also for the reconductoring of the Cricket Valley to Long Mountain segment of Line 398.

**Energy Highway AC Transmission Upgrades and Transmission Owners' Transmission Solutions**  
In 2012, the Energy Highway Task Force issued the "New York Energy Highway Blueprint" with recommendations to improve New York State's energy infrastructure.<sup>39</sup> Those recommendations resulted in the NYSPSC issuing two orders for transmission proposals on November 30, 2012. One NYSPSC Order (Case 12-T-0502)<sup>40</sup> initiated a proceeding to solicit 1,000 MW of new AC transmission capacity linking upstate and Central New York with the Lower Hudson Valley and New York City with preference for projects built along existing rights-of-way or upgrading existing lines. The other NYSPSC Order (Case 12-E-0503)<sup>41</sup> initiated a proceeding to develop a contingency plan to address reliability needs in the event of the retirement of Indian Point Energy Center (IPEC) upon the expiration of its federal operating licenses in 2015.

Evaluations for projects submitted under Case 12-T-0502 are still underway and no project approvals have been made. As projects are developed for that proceeding, interregional impacts will be evaluated through the NYISO interconnection process and will be coordinated with the JIPC.

In Case 12-E-0503, three transmission projects collectively named the Transmission Owners' Transmission Solutions (TOTS) were proposed by Consolidated Edison and New York Power Authority (NYPA) and approved by the NYSPSC as solutions:

- Marcy South Series Compensation and Fraser – Coopers Corners 345 kV line reconductoring
- Build a second Rock Tavern – Ramapo 345 kV line
- Unbottle Staten Island generation by reconfiguring substations to mitigate system contingencies and enhance cooling of underground transmission circuits from Staten Island to the rest of New York City.

These projects do not cause any adverse interregional impact and are considered by the NYSPSC as "no regrets" solutions to the retirement of IPEC in that they provide reliability benefits even if IPEC does not retire.

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<sup>39</sup> New York State Energy Highway, [New York Energy Highway Blueprint](#) (2012).

<sup>40</sup> NYSPSC, [Order Authorizing Modification of the Process to Allow For Consideration of Alternative Proposals](#), Case No. 12-T-0502 (February 21, 2014). See also New York State AC Transmission, <http://www.dps.ny.gov/ACTransmission/>.

<sup>41</sup> NYSPSC, [Order Adopting and Approving Issuance of a Draft Generic Environmental Impact Statement](#), Case No. 12-E-0503 (July 18, 2013).

### Champlain Hudson Power Express (NYISO)

The Champlain Hudson Power Express (CHPE) project is a  $\pm 320$  kV bipolar HVDC underground cable originating from Hydro Quebec's Hertel 735 kV Substation (via 1 mile 315 kV AC circuit), terminating at Astoria Annex 345 kV via a 250 ft AC underground 345 kV AC cable. The project also includes two elective SUFs: 1) a 345 kV cable originating from NYPA's Astoria Annex 345 kV terminating into Consolidated Edison's Rainey 345 kV Substation; 2) upgrading a 0.05 miles of an existing 138 kV overhead line connecting Astoria Annex 345 kV with Astoria East 138 kV, via a PAR. This project is proposed by Transmission Developers Inc., and currently undergoes Class Year 2012 Interconnection Process Facilities Study. Transient analysis is planned as part of the Facilities Study to prevent adverse control system interactions among the HVDC ties and other facilities.

#### 4.1.4 HQ Des Cantons substation to PSNH Deerfield Substation (Northern Pass)

The Northern Pass Transmission Project is a  $\pm 300$  kV bipolar HVDC project planned between the HQ Des Cantons Substation and includes 153 miles of transmission between Pittsburg and Franklin, New Hampshire (~8 miles underground).<sup>42</sup> The project includes construction of a 345 kV air insulated substation with an eight circuit breaker ring bus in Franklin, NH; a 1,200 MW bi-directional bi-polar HVDC line commutated converter station; and other supporting equipment.<sup>43</sup> The 345-kV Franklin substation will interconnect to Public Service of New Hampshire's 345-kV Deerfield substation (Point of Interconnection), located in Deerfield, New Hampshire, via a 345-kV ac overhead transmission line. The converter station in Quebec, Canada will be at Des Canton substation, which is interconnected with several transmission facilities.

This elective upgrade is proposed as a new interconnection between ISO New England and Quebec. Studies of the tie have been coordinated with both NYISO and PJM to identify and eliminate potential adverse interregional impacts. The analysis included an evaluation of control system interactions among HVDC ties to ensure system stability and acceptable loss of source contingency system response.

## 5 Process Enhancements Going Forward

### Coordinated Planning Activities

PJM, NYISO and ISO New England perform joint interregional coordination and studies as parties to the Planning Protocol. As part of the efforts to enhance interregional coordination, PJM, NYISO and ISO New England plan to continue improvement of the databases used for both joint and individual studies. The common databases will be adapted for different simulation tools used by each RTO/ISO.

<sup>42</sup> Northeast Utilities, [Northern Pass Transmission Project Proposed Plan Application, NEPOOL Reliability Committee Meeting Presentation](#) (November 19, 2013) Redacted version.

<sup>43</sup> While it will have bidirectional capability, the Northern Pass Transmission Project is limited to no more than 1,200 MW of imports into the United States from Quebec as measured at the point of interconnection at Deerfield Substation in New Hampshire. The project is prohibited from exporting power from New England to Quebec as this condition was not considered in the associated system impact studies.

The production cost and power flow data that is used for multiple regional planning studies under the Planning Protocol will be available for stakeholder review, subject to the appropriate Confidentiality and Critical Energy Infrastructure Protections (CEII). Since this data will be a combination of protected data from multiple regions, stakeholders desiring access to the data will be required to obtain authorization from each affected region.

The parties to the Planning Protocol also participate in other coordinated planning activities, as described below.

## Additional Coordinated Planning

### 5.1 Northeast Power Coordinating Council

The Northeast Power Coordinating Council (NPCC) is one of eight regional entities located throughout the United States, Canada, and portions of Mexico responsible for enhancing and promoting the reliable and efficient operation of the interconnected bulk power system.<sup>44</sup> NPCC has been delegated the authority by NERC to create regional standards to enhance the reliability of the international, interconnected bulk power system in northeastern North America. As members of NPCC, ISO New England and NYISO fully participates in NPCC-coordinated interregional studies with its neighboring areas. PJM also directly participates in select study groups by coordinating data and providing analytical support, such as the review of draft assumptions and results.

#### 5.1.1 Coordinated Planning

NPCC conducts seasonal reliability assessments, an annual long-range resource adequacy evaluation, and a periodic assessment of the reliability of the planned NPCC bulk power system. All studies are well coordinated across neighboring area boundaries and include the development of common databases that can serve as the basis for internal studies by the RTO/ISOs. Assessments of the RTO/ISOs demonstrate full compliance with NERC and NPCC requirements for meeting resource adequacy and transmission planning criteria and standards.

#### 5.1.2 Resource Adequacy Analysis

NPCC establishes requirements for resource adequacy over the planning period. Analyses are conducted to determine the systemwide and local-area needs for resource adequacy; and the region's efforts to meet the need for resources through markets, the queue, and energy-efficiency resources planned by the states.

#### 5.1.3 NPCC Overall Transmission Assessment

NPCC conducts seasonal reliability assessments, an annual long-range resource adequacy evaluation, and a periodic assessment of the reliability of the planned NPCC bulk power system.<sup>45</sup>

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<sup>44</sup> The NPCC region covers nearly 1.2 million square miles populated by more than 55 million people. NPCC in the United States includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario, Québec, and the Maritime provinces of New Brunswick and Nova Scotia. As full members, New Brunswick and Nova Scotia also ensure that NPCC reliability issues are addressed for Prince Edward Island.

<sup>45</sup> NPCC seasonal reliability assessments are available in the [NPCC Library](#). For the most recent seasonal assessment, see the [NPCC Reliability Assessment for Winter 2013-2014](#) (December 3, 2013).

All studies are well coordinated across neighboring area boundaries and include the development of common databases that can serve as the basis for internal studies by the ISO/RTOs. Assessments of both ISO-NE and NYISO demonstrate full compliance with NERC and NPCC requirements for meeting resource adequacy and transmission planning criteria and standards.

## 5.2 RFC 2020 Long-Term Assessment of Transmission System Performance

As one of the eight NERC-approved Regional Entities in North America, ReliabilityFirst Corporation (RFC) conducts a long-term transmission assessment annually in order to satisfy its responsibility to provide a judgment on the ability of the regional transmission system to operate reliably under the expected range of operating conditions over the applicable assessment period as required by NERC reliability standards.<sup>46</sup> RFC complies with this mandate by examining work already performed according to the planning processes of PJM, MISO, MRO, SERC, and VACAR and studies performed by the Eastern Interconnection Reliability Assessment Group (ERAG).<sup>47</sup> In addition, RFC performs its own long term transmission assessment in conjunction with affected transmission owners, which includes identification, analysis, and projections of trends in transmission adequacy and other industry developments that may impact future electric system reliability.

In December 2013, RFC issued a report summarizing the results of a long-term assessment of the projected performance of the transmission system within RFC's footprint for the 2023 Summer peak season.<sup>48</sup> The assessment evaluated the performance of the transmission system within RFC via a series of power flow analyses. The assessment was based on the transmission topology, load and generation dispatch modeled in the 2023 EIPC Summer Peak roll-up case. The assessment did not attempt to determine load or generator deliverability, Planning Transfer Capability (PTC), Available Transfer Capability (ATC), Available Flowgate Capacity (AFC), the availability of transmission service, or provide a forecast of anticipated dispatch patterns for the 2023 Summer season.

The base case was examined under NERC criteria category A and B conditions. The case was then stressed under thirty-one different transfer scenarios that were considered to represent severe system conditions that may be experienced under adverse weather, generation deficiencies, transmission configuration or other emergency type situations. These tests go beyond the normal RTO NERC criteria testing that would require upgrades for reliability. RTO internal planning processes establish all needed system upgrades for full compliance with NERC criteria.

Based on the results of the work conducted by RFC, MISO, PJM, and ERAG and summarized in this assessment report, it is expected that the transmission system within the RFC footprint will perform well over a wide range of conditions.

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<sup>46</sup> ReliabilityFirst Corporation, [2018 Near-Term Assessment and 2023 Summer Long-Term Assessment of Transmission System Performance](#) (December 2013). Additional resources available at: <https://www.rfirst.org/Pages/Rfirst.aspx>.

<sup>47</sup> Eastern Interconnection Reliability Assessment Group, see <https://rfirst.org/reliability/easterninterconnectionreliabilityassessmentgroup/pages/default.aspx>.

<sup>48</sup> RFC [2023 Summer Long-Term Assessment of Transmission System Performance](#) (December 2013).

### 5.3 IRC Activities

Created in April 2003, the ISO/RTO Council (IRC) is an industry group consisting of the 10 functioning ISOs and RTOs in North America.<sup>49</sup> 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 much of North America. In fulfilling this mission, the IRC balances reliability considerations with market practices that provide competitive and reliable service to electricity users. 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. As part of the ISO/RTO authorization to operate, each ISO/RTO independently and fairly administers an open, transparent planning process among its participants that provides for coordination, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation. This ensures a level playing field for infrastructure development driven efficiently by competition and meeting all reliability requirements.

The IRC has coordinated filings with FERC on many issues, such as those concerning the FERC *Notice of Proposed Rulemaking (NOPR) on Small Generator Interconnection Agreements and Procedures* and other technical issues.<sup>50</sup> In addition, the IRC submitted joint comments in April to the National Institute of Standards and Technology (NIST) Request for Information (RFI) on the Obama administration's executive order on cyber security.<sup>51</sup> The IRC noted that mandatory and enforceable cybersecurity standards already are in effect for the bulk electric power system and highlighted the initiatives taken by the electric industry to secure the grid against cyberattacks.<sup>52</sup> The IRC also is acting to address the challenges of integrating demand resources and wind generation and, through its representatives, is leveraging the efforts of NERC's Integrating Variable Generation Task Force.<sup>53</sup> The IRC participates on other NERC task forces and committees.

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<sup>49</sup> ISO/RTO Council information and materials available at: <http://www.isorto.org/pages/home>.

<sup>50</sup> FERC, *Small Generator Interconnection Agreements and Procedures, notice of proposed rulemaking*, 142 FERC ¶ 61,049 (January 17, 2013). *ISO/RTO Council Comments on Notice of Proposed Rulemaking, Small Generator Interconnection Agreements and Procedures* (June 3, 2013).

<sup>51</sup> *Improving Critical Infrastructure Cybersecurity*, White House Executive Order (February 12, 2013), <http://www.whitehouse.gov/the-press-office/2013/02/12/executive-order-improving-critical-infrastructure-cybersecurity>.

<sup>52</sup> IRC, *Response of the ISO/RTO Council to the NIST's February 26, 2013, RFI* (2013).

<sup>53</sup> NERC, *Integration of Variable Resources Task Force information and materials*.

## 5.4 NERC Long Term Reliability Assessment and Other Studies

In December 2013, NERC issued its annual Long Term Reliability Assessment (LTRA), analyzing reliability conditions across the North American Continent.<sup>54</sup> This report describes transmission additions, generation projections, and reserve capability by reliability council area. Within a ten-year planning horizon, both RFC and NPCC are expected to have sufficient reserves to meet reliability needs. Projected load growth continues to be sluggish in both areas due to a combination of slower economic growth, increased participation in demand-side management programs (including efficiency gains from new appliance standards), and additional reliance on behind-the-meter generation. Challenges noted for NPCC include aging infrastructure issues, integration of variable resources, growing dependence on natural gas generation and the retirement of fossil-fueled and nuclear generation. Challenges noted for the RFC area include a large amount of fossil-fueled generation at risk of retirement during the assessment period due to environmental retrofit costs. While there is no overall resource adequacy concern, localized reliability concerns may need to be addressed.

## 5.5 Eastern Interconnection Planning Collaborative

### 5.5.1 Background

The electric power planning authorities of the Eastern Interconnection, including NYISO, PJM and ISO-NE, formed the Eastern Interconnection Planning Collaborative (EIPC) in 2009 to address their portion of North American planning issues and manage the process for combining the existing regional transmission expansion plans and for conducting transmission analysis on an interconnection-wide basis.<sup>55</sup> The EIPC study process is based on “bottom-up” planning, and EIPC is committed to interactive dialogue and open, transparent proceedings with input from a broad base of interested stakeholders.

During its formation, EIPC received a grant from the DOE to develop an Eastern Interconnection-wide transmission planning process, including broad stakeholder participation with funding provided under the American Rehabilitation and Recovery Act (ARRA).<sup>56</sup> The initial work under this grant began in 2010 and concluded at the end of 2013. Phase I began with the establishment of an interconnection-wide Stakeholder Steering Committee consisting of representatives of six stakeholder sectors, including a Canadian representative. During Phase I, stakeholders developed numerous scenarios to reflect a variety of assumptions regarding the impacts of different public policies on the electricity sector and the amount of future load growth.

Phase I culminated at the end of 2011 with the submission of a Report to the DOE describing the regional plan integration, the macroeconomic analysis of eight energy futures and 72 related sensitivities representing the stakeholders’ views of various potential public policy future states

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<sup>54</sup> North American Electric Reliability Corporation, *2013 Long-Term Reliability Assessment* (December 2013).

<sup>55</sup> Additional information on the EIPC is available at <http://www.eipconline.com/>.

<sup>56</sup> American Rehabilitation and Recovery Act of 2009, Pub. L. 111-5, 123 Stat. 115 (2009).

over a 20-year study horizon.<sup>57</sup> The results of the Phase I work were used to develop resource-expansion options for the three final scenarios selected for more detailed analysis during Phase II.

The Phase II work, which began in 2012, included a series of power flow and contingency analyses for 2030 focusing on power system facilities above 200 kV and resulting in detailed transmission buildouts for each scenario based on single-contingency overloads and selected NERC reliability criteria. The production costs for each scenario were analyzed using the transmission buildouts developed by the Planning Authorities and the generation resources determined in Phase I. Following the initial simulations, stakeholders selected six additional sensitivity cases to investigate wind curtailments under various conditions and the effects of increased load and gas prices. The EIPC and its consultants also developed estimates of high-level, overnight capital costs and operations and maintenance costs projected for 2030 for the resource and transmission facilities identified in each scenario. A draft Phase II Report was submitted to the DOE in December 2012 describing the results of the additional analyses.<sup>58</sup>

### 5.5.2 Current Planning Activities

In 2013, EIPC continued to analyze the Eastern Interconnection transmission system. The Roll-Up case, combining each region's plan into a comprehensive model of the Eastern Interconnection, was updated from the previous case developed for Phase I of the DOE study. A draft Roll-Up Report was posted for comment in December 2013. The draft Report was revised to address stakeholder comments and the final Report was posted in February 2014.<sup>59</sup> In addition, during 2013 the EIPC developed a new process for gathering stakeholder input based upon the existing regional stakeholder processes. The Planning Authorities are soliciting feedback from Stakeholders on potential scenarios to be analyzed during 2014. The final scenarios are expected to be determined and posted, together with the 2014 work plan in April 2014.

### 5.5.3 Gas Electric System Interface issues and the EIPC Study

During its review of the draft Phase II Report, the DOE identified a gap between electric and natural gas system infrastructures and noted that recent changes in the natural gas markets anticipate increased reliance on natural gas for power generation in the future. DOE requested that the EIPC begin to evaluate the interaction between natural gas and electricity from a planning perspective, and proposed an extension in the deadline for completion of the award thru mid-2015 in order to accommodate this analysis. During 2013, six of the EIPC Planning Authorities (ISO-NE, NYISO, PJM, TVA, MISO and IESO), reconvened the Stakeholder Steering Committee (SSC) with the addition of a Gas Sector, developed a Statement of Work (SOW), solicited stakeholder comments and issued an

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<sup>57</sup> EIPC, *Phase I Report: Formation of Stakeholder Process, Regional Plan Integration and Macroeconomic Analysis*, DOE Award Project DE-OE0000343 (December 2011). Phase II resources are available at [http://eipconline.com/Phase\\_II.html](http://eipconline.com/Phase_II.html).

<sup>58</sup> EIPC, Phase II Report: Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios (December 22, 2012). Available in three files at [http://www.eipconline.com/Phase\\_II\\_Documents.html](http://www.eipconline.com/Phase_II_Documents.html).

<sup>59</sup> EIPC, *Steady State Modeling and Load Flow Working Group Report for 2018 and 2023 Roll-Up Integration Cases, Final Report* (February 14, 2014).

RFP, including the final SOW, for competitive bid to perform the technical analysis required for the Gas Electric System Interface Study. In October, the bid was awarded to Levitan and Associates.

The Gas Electric System Interface Study kick-off began with a SSC Meeting on October 29, 2013 followed by a series of Webinars in December 2013, January and February 2014. The Study consists of four principal tasks or “Targets” as follows:

- **Target 1:** Develop baseline assessment, including descriptions of the natural gas-electric system interfaces, interaction effects, specific drivers of the pipeline/LDC planning process
- **Target 2:** Evaluate the capability of the natural gas systems to meet individual and aggregate core and noncore gas demand over a 5- and 10-year horizon
- **Target 3:** Identify contingencies on the natural gas system that could adversely affect electric system reliability, and *vice versa*
- **Target 4:** Review the operational / planning issues affecting the availability of dual fuel capable generation, including fuel assurance objectives

The Study schedule calls for the bulk of the technical analysis to be conducted during 2014. Draft reports will be provided for stakeholder input for each of the above Targets. A draft final report will be developed, posted for comments, revised and finalized for submission to the DOE by mid-year 2015.

## 6 Emerging Issues with Potential Interregional Impacts

The ISO/RTOs have coordinated on a number of common issues that affect interregional planning. The JIPC is one of several venues through which ISO New England, NYISO, and PJM share information concerning their respective planning efforts to assess the impact implementation of existing and pending state, regional and federal policies may have on existing and planned generation and transmission resources and to expedite the efficient and reliable integration of these resources into the overall system. Several of these issues are discussed below.

### 6.1 Environmental

Existing and pending state, regional, and federal environmental requirements, addressing air pollution (smog, regional haze, mercury, and other air toxics), greenhouse gas emissions (such as carbon dioxide and methane), the use of cooling water from rivers and bays, and wastewater discharges into water bodies and public treatment works, will affect many Northeast generators in the 2015 to 2022 timeframe. When implemented, the full suite of environmental regulations, currently in various stages of promulgation, could affect generator economic performance in several ways. Generator capital costs could rise for modifying or replacing cooling systems or wastewater discharge or air pollution controls, and operating costs could increase through the increased use of new and existing pollution control devices. The regulations also may affect reliability by limiting generator energy production, reducing capacity output, or contributing to unit retirements. Environmental regulations affecting system performance are being monitored for their potential effects within the region and inter-regionally.

## 6.2 Integration of Intermittent and Distributed Resources

The Northeast states have targets, through Renewable Portfolio Standards (RPSs), for the proportion of electric energy that renewable resources and energy efficiency provide. Because the states are revising these targets to reflect different amounts and types of resources that qualify under RPSs, ISO-NE, NYISO, and PJM cannot project the precise amount of regional renewable energy goals. However, the electric energy reductions from passive demand resources, along with the state targets for renewable resources, will meet some portion of the Northeast's total projected electric energy use by 2022.

Each ISO/RTO accounts for distributed resources and accounts for them as part of their planning process. While distributed resources may reduce the need to build physical infrastructure, successfully integrating increasing quantities of distributed resources into the electric power system presents many challenges. These include operational, planning, and market issues presented by increasing penetrations of such resources. These challenges are being reflected in interregional studies.

Options for meeting, or exceeding, the region's RPS targets include developing the renewable resources in the interconnection queues of ISO-NE, NYISO, and PJM, importing qualifying renewable resource energy from adjacent balancing authority areas, building new renewable resources in the Northeast not yet in the ISO/RTO interconnection queues. Other options include developing "behind-the-meter" projects, using eligible renewable fuels in existing generators or resorting to alternative compliance payments by LSEs to satisfy a state RPS obligation. Various stakeholders are working with the Northeast States to implement, coordinated, competitive procurement of renewable resources in parts of the region.

## 7 Summary and Conclusions

### 7.1 Summary

This NCSP report demonstrates the collaborative effort undertaken by ISO New England, NYISO, and PJM in their coordination and continued development of interregional planning efforts. Each of the ISO/RTOs involved develop individual system reliability plans, production cost studies, and interconnection studies mindful of significant interregional impacts. To facilitate interregional coordination and communication between all interested parties, the JIPC and IPSAC were established to implement the Planning Protocol.

Order 1000 will affect regional and interregional transmission planning, cost allocation and consideration of public policy requirements. The Final Rule requires all transmission providers to develop further procedures with neighboring regions to provide for:

- (1) The sharing of information regarding the respective needs of each region, and potential solutions to those needs; and

- (2) the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective solutions to those regional needs

ISO New England, NYISO and PJM, with input from their stakeholders and IPSAC, jointly developed the Amended Planning Protocol and other documents to be compliant with these new requirements.

ISO New England, NYISO and PJM provide a summary of their individual system plans in an effort to identify opportunities for interregional coordination improvements. System reliability plans and economic studies for each of the ISO/RTOs are discussed with references to the full reports

A listing of recent projects in ISO New England, NYISO, and PJM demonstrate that the ISO/RTOs have coordinated with each other on issues that could affect the interregional performance of the overall system. This listing contains reliability, economic, and system interconnection projects planned by their respective regions.

There are a number of process enhancements going forward. For example, as part of these efforts to enhance interregional coordination, ISO New England, NYISO and PJM plan to continue improving the coordinated production cost database for both joint and individual studies.

Additional interregional studies for resource adequacy, transmission planning, economic performance, and other issues have been well coordinated through the JIPC, NPCC/RFC, NERC and EIPC. Interregional issues such as gas/electric interactions, environmental regulation, and renewable/intermittent resources have also been well coordinated through the JIPC, IRC and EIPC.

## 7.2 Conclusions

ISO-NE, NYISO, and PJM continue to coordinate interregional transmission planning under the Planning Protocol. Communication between the members of the JIPC has been beneficial to regional needs as well as neighboring system concerns. Input from the IPSAC provides additional perspective in addressing current and future challenges.

While much has been accomplished, there is still more that can be done. The ISO/RTOs will continue working together to improve their current methods of sharing system information for the purposes of joint and individual planning studies. Interregional issues will need to be addressed, such as the increased scrutiny into the gas/electric interaction and the more stringent environmental regulations being introduced. The ISO/RTOs are improving their level of coordination by enhancing the timelines and procedures for interregional planning.

## 8 Appendices

### 8.1 List of Abbreviations

ACP	Alternative Compliance Payment
AFC	Available Flowgate Capacity
ATC	Available Transfer Capability
ARRA	<i>American Rehabilitation and Recovery Act of 2009</i>
BPS	Bulk Power System
BPTF	Bulk Power Transmission Facilities
CARIS	Congestion Assessment and Resource Integration Study
CEII	Confidentiality and Critical Energy Infrastructure
CELT	Capacity, Energy, Loads, and Transmission
CHPE	Champlain Hudson Power Express
DG	Distributed Generation
DOE	US Department of Energy
EIPC	Eastern Interconnection Planning Collaborative
EPAct	<i>Energy Policy Act of 2005</i>
ERAG	Eastern Interconnection Reliability Assessment Group
FERC	Federal Energy Regulatory Commission
HVDC	High Voltage Direct Current
IESO	Independent Electric System Operator of Ontario
IPEC	Indian Point Energy Center
IPSAC	Inter-Area Planning Stakeholder Advisory Committee
IRC	ISO/RTO Council
ISO-NE	Independent System Operator of New England
JIPC	Joint ISO/RTO Planning Committee
LSE	Load Serving Entity
LTRA	Long Term Reliability Assessment
MISO	Midcontinent Independent System Operator
MPRP	Maine Power Reliability Program
NEEWS	New England East-West Solution
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSEG	New York State Electric & Gas Corporation
NYSDPS	New York State Department of Public Service
NYSPSC	New York State Public Service Commission
OATT	Open Access Transmission Tariff
PAR	Phase Angle Regulator
PTC	Planning Transfer Capability
PV	Photovoltaic
RFC	Reliability <i>First</i> Corporation
RNA	Reliability Needs Assessment
ROFR	Right-of-First-Refusal
RSP	Regional System Plan

RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Operator
SEMA	Southeastern Massachusetts
SPS	Special Protection System
SSC	Stakeholder Steering Committee
SVC	Static VAR Compensator
TO	Transmission Owner
TVA	Tennessee Valley Authority
VACAR	Virginia-Carolinas

## 8.2 References

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

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.

### **For ISO-New England stakeholders:**

Materials for the IPSAC meetings are posted at: [http://www.iso-ne.com/committees/comm\\_wkgrps/othr/ipsac/mtrls/index.html](http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/index.html).

### **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](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](http://www.nyiso.com/public/services/customer_relations/index.jsp).

ISO New England

[ISO-NE 2013 Regional System Plan](#) (November 8, 2013)

ISO-NE, [Open Access Transmission Tariff](#) (January 1, 2013)

ISO-NE 2014 Capacity, Energy, Loads, and Transmission (CELT) Forecast Report, in May 2014.  
Earlier ISO-NE CELT reports are available at <http://www.iso-ne.com/trans/celt/report/>.

New York Independent System Operator

NYISO [2013 Congestion Assessment and Resource Integration Studies Report](#) (December 3, 2013)

[http://www.nyiso.com/public/webdocs/markets\\_operations/services/planning/Planning\\_Studies/Economic\\_Planning\\_Studies\\_\(CARIS\)/CARIS\\_Final\\_Reports/2013\\_CARIS\\_Final\\_Report.pdf](http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2013_CARIS_Final_Report.pdf)

North American Electric Reliability Corporation

North American Electric Reliability Corporation, [2013 Long-Term Reliability Assessment](#) (December 2013).