FINAL DRAFT

NORTHEASTERN COORDINATED SYSTEM PLAN: 2005

A STATUS REPORT OF THE NORTHEASTERN ISO/RTO PLANNING COORDINATION PROTOCOL

April 6, 2005

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I. INTRODUCTION

The New York Independent System Operator (NYISO) and ISO-New England (ISO-NE) began discussions regarding enhanced coordination of planning between the two regions in the Fall of 2003. It was soon recognized that a broader initiative including other transmission operators in the Northeast would be beneficial. Accordingly, in January 2003 an inter-area Transmission Coordination Task Force was formed including ISO-NE, the NYISO, PJM Interconnection, LLC (PJM) and the Canadian members of Northeast Power Coordinating Council (NPCC). NPCC staff also participated in these discussions.

Development of a Planning Coordination Protocol for the Northeast Region

These discussions resulted in the development of a draft protocol for the coordination of planning for the Northeast region, which was patterned after the planning coordination agreement that was then under development between PJM and the Midwest Independent System Operator (MISO). (This agreement was filed with the FERC on December 31, 2003.) During the first half of 2004, ISO-NE, NYISO, and PJM solicited stakeholder input on the draft protocol. Stakeholders in all regions were very supportive of moving ahead with this initiative.

The ISOs incorporated the input received during their stakeholder discussions and finalized the protocol document in December 2004. The initial parties to the protocol are ISO-NE, NYISO and PJM. The Independent Electricity System Operator of Ontario (IESO), Hydro-Québec TransÉnergie, and New Brunswick Power (NB Power), while not parties to the protocol, have agreed to participate on a limited basis in the data-sharing and information-exchange process and in regional planning studies for projects that may have inter-area impact to ensure better coordination in the development of the interconnected power system in the Northeast. It is intended that the activities of the parties and other participants, as defined under the protocol, would be conducted in close coordination with the Regional Reliability Councils of the northeastern United States and Canada (i.e., NPCC and the Mid-Atlantic Area Council (MAAC). Section II provides a summary of the Protocol, which is attached in its entirely as Appendix A.

Current Inter-Regional Planning Coordination Activities

There has been a long history of coordination of planning activities among the former power pools—now ISOs—and other control area operators in the northeastern regions of the United States and Canada. This coordination has taken place both under the auspices of the North American Electric Reliability Council's (NERC) Regional Councils, which are active in the Northeast (the NPCC and MAAC) as well as through specific ad hoc study groups between and among various ISOs and transmission owners on issues of mutual interest.

The NERC, as well as its Northeast Regional Councils, MACC and NPCC, were established after the blackout of 1965, not only in an effort to prevent reoccurrences, but also to ensure the continued reliability of the northeastern United States and interconnected Canadian electrical network. The members of NPCC and MAAC actively participate in inter-regional, coordinated transmission studies with their neighboring Control Areas.

NPCC planning studies address inter-regional reliability issues and ensure that the plans of the member systems are well coordinated. Similarly, MAAC planning studies ensure the reliability, including both the adequacy and security, of the interconnected bulk power system in the MAAC region through standard setting, compliance monitoring, and enforcement processes relating to the coordinated planning and operation of transmission and generation facilities.

The August 14, 2003, blackout, which affected a vast area primarily in New York, Ontario, and the Midwest, vividly demonstrated the need for even more effective coordination and cooperation. Interconnected operation of the system during the cold snap of January 2004 (January 2004 Cold Snap) improved the reliability of service and mitigated the adverse consequences of a lack of fuel diversity. NPCC Reliability Criteria is specific and mandatory, as enforced through a non-monetary sanctioning system for the enforcement of compliance with reliability criteria. MAAC Reliability Criteria provides for the due process resolution of issues that arise in the development, implementation, compliance monitoring, and enforcement of reliability standards considering the interests of all participants.

In addition to their participation in the planning activities of the NPCC and MAAC, the ISOs and other Control Areas also conduct their own planning studies, which contain more detailed analyses of the needs of their respective systems. These individual planning studies use models of the adjacent regions, many of which are developed through the activities of the Regional Councils. A summary of the most recent plans of each of the northeastern ISOs and Control Areas is included in Section III, with links to the complete plans provided in Appendix B.

Section IV provides a summary of the planning initiatives of the NPCC and MAAC, while further details are included in Appendices C and D.

Northeastern Coordinated System Plan: 2005

There are a number of initiatives contained in the Protocol, some of which are already underway. The principal longer-term initiative is the development of a Northeastern Coordinated System Plan. This document represents an important first step by consolidating the system assessments and plans of each of the Control Areas as well as highlighting existing inter-regional planning initiatives. The intention of the parties is to seek stakeholder input and to begin the important initiative of having a truly coordinated plan begun no later than mid-2005 for completion by Summer 2006. Section VI provides more details on this effort to conduct joint system assessments and to identify system improvements that may provide inter-regional benefits.

II. NORTHEASTERN ISO-RTO PLANNING COORDINATION PROTOCOL: SUMMARY

Objectives of the Protocol

The Protocol provides a vehicle for enhanced coordination of planning throughout the Northeast whose primary purpose is to contribute to the ongoing reliability and the enhanced operational performance and efficiency of the Northeastern bulk power system. In so doing, the process will also aid in the resolution of seams between the regions. The participants recognize that their activities under the Protocol will support and supplement each region's individual planning procedures and will build upon their joint activities under the Regional Councils.

Committee Structure

Two new committees will be established to support the coordinated planning activities envisioned under the Protocol. These are: (i) Inter-area Planning Stakeholder Advisory Committee (IPSAC) and (ii) Joint ISO/RTO Planning Committee (JIPC). Their functions are as follows.

The IPSAC will be the primary means for providing stakeholder input for the development of the Northeastern Coordinated System Plan (NCSP). Membership on the IPSAC will be open to all stakeholders within the region, including market participants, governmental agencies, and regional reliability councils. It is envisioned that the IPSAC will meet prior to the start of each cycle, to review and provide feedback to the coordinated planning process during the development of the NCSP, and upon completion, to review the results of the planning process.

The JIPC will be comprised of representatives of the planning staff of the parties to the Protocol and will have primary responsibility for the coordination of all activities under the Protocol, including the development of procedures, the conduct of planning analyses, and the production of the NCSP. Working groups will be established as needed to fulfill the responsibilities under the protocol.

Key Elements of the Protocol

The Protocol addresses the establishment of procedures for the following key elements:

- Data and information exchange to ensure proper coordination of databases and planning models for both individual and joint planning activities conducted by the parties
- Coordination of interconnection requests that are likely to have cross-border impacts
- Analysis of firm transmission service requests that are likely to have cross-border impacts
- Development of a Northeast Coordinated System Plan (See Section VI)

In addition, the Protocol recognizes that cost-allocation procedures for projects that have cross-border impacts will be addressed consistent with the provisions of each party's tariff and applicable federal or provincial regulatory policy.

Finally, the Protocol contains provisions for dispute resolution, if needed, of any issues that cannot be resolved within the JIPC.

Consistency with Tariffs

The parties recognize that changes in their respective tariffs may be required to implement certain provisions of the protocol and have agreed to use their best efforts to achieve the necessary approvals through their respective governance processes. Until such tariff changes are enacted, or if one or more parties are unable to enact such tariff changes, the affected aspects of the protocol will not be implemented, or will be modified, to ensure consistency with the tariffs of the parties.

Communications Website

A website has been established, administered by the NPCC, to provide a means for the broad communication of the activities related to the coordinated planning process. This website may be accessed via the following link: **www.interiso.com**

The following table summarizes the inter-regional coordination of system planning and demonstrates the benefits to be achieved under the Protocol.

Table 1
Inter-Regional Coordination of System Planning

ITEM	PAST	RECENT IMPROVEMENTS	PROTOCOL	COMMENTS
Coordination of System Plans	NPCC and PJM review of individual Control Area assessments for inter-area impacts. NPCC, PJM and MEN studies to review inter-area and inter-regional impacts	Better informal coordination among all control areas	Joint studies to ensure individual Control Area plans are well coordinated Identification of improvements required for reliability Study process similar to existing ISO/RTO practices including open stakeholder groups	Coordination of data, timelines, scopes of work, etc. will greatly improve inter-area planning. Approvals are subject to each region's planning procedures.
Tariff Studies	NPCC and PJM review of individual Control Area assessments for inter-area impacts	Better informal coordination among all control areas	Recognizes different interconnection requirements Early notification of inter-area impacts Payment for full scope of work that considers inter-area issues Website listing queue of projects with potential inter-area impacts Network upgrades identified as part of the System Impact Study under terms and conditions of potentially impacted system consistent with FERC and regulatory policy	Customers understand inter-area impacts at earliest possible date. Customers to address remote area upgrades as a requirement of interconnection Many issues to be addressed by JIPC with input from stakeholders

ITEM	PAST	RECENT IMPROVEMENTS	PROTOCOL	COMMENTS
Cost Allocation for Projects with Inter-Area Impact	Consistent with each Control Area's Tariff, including negotiated agreements. FERC is the ultimate arbitrator.	Earlier identification of issues achieved through informal coordination	Cost of elements of the NCSP and Tariff studies will be addressed consistent with provisions of each Control Area's Tariff.	No obligation for remote system to make NCSP improvements for neighbor. Will require further evolution

III. SUMMARY OF AREA PLANS

This section contains summaries of the most recent planning analyses conducted by each of the ISOs and Control Areas in the Northeast Region. Since these studies contain considerable detail and are lengthy, Appendix B provides electronic links to the complete studies.

As noted above, under the Protocol, it is explicitly recognized that each individual area will retain the responsibility to perform such system planning activities as those summarized in this section to fulfill their responsibilities under their tariffs and agreements and conform to applicable reliability requirements. Each party and participant has agreed to document their respective procedures, methodologies, and rules that are utilized in the preparation of their respective system-planning reports. The findings of each area's applicable periodic system plan will be incorporated into the Northeastern Coordinated System Plan. This process is more fully described in Section VI.

The government of Ontario has created a new institution, the Ontario Power Authority (OPA), which has the obligation to ensure long-term supply adequacy in Ontario. This entity will take over some of the functions currently assigned to the IESO (formerly the Independent Electricity Market Operator or IMO), such as forecasting, but will also be responsible for developing and maintaining an integrated system plan, to ensure the smooth cooperation of both electricity generation and transmission in Ontario. In addition to its forecasting and planning functions, the OPA will be responsible for calling on the private sector when needed to build new generation capacity through a competitive and transparent procurement process, which would foster innovation and creative approaches to meeting Ontario's supply challenges.

A. INDEPENDENT ELECTRICITY MARKET OPERATOR OF ONTARIO

10-YEAR OUTLOOK (Issued: April 29, 2004)

Executive Summary

Ontario's electricity system faces significant challenges over the next 10 years. The uncertainty surrounding the return to service of Pickering A nuclear units, the lack of new generation investment, and the commitment to shut down 7,500 MW of coal-fired generation by
December 31, 2007, all contribute to a potentially severe shortfall. New transmissions, supply- and demand-side initiatives are urgently needed to address this gap and secure Ontario's energy future.

The need is most pressing in the Toronto area, to deal with the immediate impact of the April 30, 2005, shutdown of the Lakeview Thermal Generating Station. Plans are being implemented to address this in the short term. In the longer term, additional generation is also required in the Toronto area to replace the Lakeview generating capacity and to meet load growth in the Greater Toronto Area (GTA).

Each year, the Independent Electricity Market Operator (IMO) publishes an integrated assessment of the security and adequacy of the Ontario electricity system over the next 10 years. This report presents the IMO assessment for the 10-year period from 2005 to 2014. It is based on the IMO's forecast of electricity demand, information provided by Ontario generators on the supply that will be available, and the latest information on the configuration and capability of the transmission system.

Electricity Supply Outlook

Additional Ontario electricity supply- and demand-side measures are required to maintain supply adequacy into the future and to reduce Ontario's dependency on supply from other jurisdictions.

The reactivation of 2,000 MW of nuclear capability, and the addition of 500 MW of new gas-fired generation over the last 18 months, and the addition of 755 MW of gas-fired generation expected by this summer has eased concerns over the next 18 months. However, more resources are required in every year of the 10-Year Outlook period, some with a high degree of urgency. With the lead times and the quantities of supply and demand resources needed over this period, commitments are required now.

Given the government's commitment to shut down coal-fired generation—which accounts for some 25 percent of Ontario's current generating capacity—a substantial amount of new supply, refurbished generation, and demand-side resources could be required by 2014.[1] Allowing for typical resource

[1] The Government of Ontario has since indicated it will only replace coal plants in a responsible way that protects Ontario's supply. The plants will be removed from service only after replacements are up and running

unavailability of 10%, approximately 12,850 MW of supply or demand measures would need to be in place to reliably cover the 2014 peak capacity deficiency of 11,600 MW. The exact amount and timing of the new resources hinges on a variety of factors, including demand growth and the performance of Ontario's aging generation infrastructure. The provincial government has indicated that it is developing plans to address this situation.

Proposals for over 30 future generating facilities totaling more than 6,000 MW have been submitted to the IMO. From this total, the capacity available to meet system needs at peak times is estimated to be only 4,000 MW, based on the various capacity factors associated with each generation type. This much capacity, or its equivalent and more, is needed to meet Ontario's requirements. However, construction of only three of the proposed facilities has started. The provincial government has initiated a Request for Proposals process seeking up to 2,500 MW of new generating capacity and/or demand-side initiatives to be developed as early as 2005. The government will also be seeking up to 300 MW of renewable energy capacity to be in service as soon as possible. As in previous Outlooks, the IMO does not include in its assessment those projects for which construction has not begun. Only one of the remaining three Pickering A units is included.

The increasing age of Ontario's generation was identified in last year's Outlook as an emerging issue toward the end of the study period and beyond, as much of the existing generation infrastructure reaches or exceeds its nominal life.

A significant amount of new generation needs to be situated close to Toronto. To meet power system needs, the Lakeview coal-fired generating station in Mississauga, scheduled to be removed from service on April 30, 2005, in accordance with Ontario Regulation 396/01, should be replaced and augmented by generation or demand initiatives in the GTA, east of Milton, by 2006.

All the proposed new generation projects for the Toronto zone address this local requirement, and their timely completion would alleviate supply concerns in downtown Toronto and the western GTA. These projects will complement, but not replace, the need for transmission reinforcements.

With respect to the retirement of coal-fired generation announced by the government, with few exceptions, replacement capacity must be located in the same electrical zone and have the same overall operational characteristics as the station being retired, in order to avoid grid-adequacy and operability issues.

Transmission

The need for additional supply and transmission reinforcement to maintain the reliability of the GTA was thoroughly documented in the *2003 10-Year Outlook*. The plans to address GTA concerns have evolved substantially over the past 12 months. However, it is critically important that sufficient projects are implemented in a timely manner to maintain the required level of reliability.

Several transmission infrastructure additions are required before 2005 summer-peak conditions in order to prevent overloading of autotransformers and to provide adequate reactive power to maintain acceptable voltages throughout the western portion of the GTA. Hydro One will be adding a new Transformer Station in Markham, extending an existing 230 kV double circuit line between Richmond Hill and Markham, and installing new equipment in a number of stations within the GTA.

The IMO has directed Ontario Power Generation to retain the option to convert two Lakeview generating units to synchronous condensers, should the reactive power needed to support voltages in the GTA not be available from other sources. No coal burn is required for this mode of operation.

For implementation further along in the decade, Hydro One has proposed two alternative transmission projects to address the need for a third supply to downtown Toronto—a Direct Current (DC) Option and an Alternating Current (AC) Option. Both options meet IMO criteria and improve the reliability of supply to downtown Toronto. However the DC option is preferred, as it requires fewer system upgrades.

Additional transmission facilities have also been proposed for the areas west and north of Toronto to increase the supply capability to southern Mississauga, southern Oakville, Markham, Richmond Hill, Vaughan, Newmarket, and Aurora. However, the supply delivery capability to the rest of Mississauga, and to Brampton, Milton, and northern Oakville remains a concern. Due to the high rate of load growth in these areas, there is a need to increase transmission capability.

New transmission reinforcements are also required for other parts of Ontario including Kitchener-Waterloo, Cambridge, Guelph, and Windsor, as discussed in the recent Hydro One report, *Transmission Solutions – A 10-Year Transmission Plan for the Province of Ontario 2004-2013*.

Ontario Demand Forecast

Without significant conservation efforts, energy consumption is forecast to grow from about 156 terawatt-hours (TWh) in 2005 to about 169 TWh in 2014, an average annual growth rate of energy of 0.9%.

Normal weather peak demands are expected to increase from about 24,160 MW in 2005 to 26,610 MW in the summer of 2014, an increase of 2,450 MW. Under extreme weather conditions, the summer peak is projected to approach the 30,000 MW level by the end of the forecast period.

B. NEW ENGLAND INDEPENDENT SYSTEM OPERATOR

2004 REGIONAL TRANSMISSION EXPANSION PLAN (Approved by ISO-NE Board of Directors October 21, 2004)

Overview

ISO New England (ISO-NE) is pleased to present its Regional Transmission Expansion Plan report for 2004 (RTEP04). This report presents a regional *system* expansion plan that addresses all aspects of planning to ensure the reliable and efficient operation of the New England bulk electric power system and wholesale electricity marketplace.

RTEP04 is the result of a year long regional planning effort that examined the bulk electric power system throughout New England. RTEP04 improves on RTEP03 with the following enhancements:

- More comprehensive description of transmission projects
- Detailed examination of the resource requirements of the system and load pockets[2] in the framework of operable capacity
- Analysis that provides information on the amount, location, and timing of required resources; and
- Inclusion of historical market data and observations

By identifying system needs, the planning assessment provides information to the wholesale electricity marketplace so that efficient market solutions can be developed to solve power system problems. Such market responses may be investment in generating units, merchant transmission facilities, or demand response programs. RTEP04 also identifies regulated transmission solutions that may be required to ensure reliability and wholesale market efficiency if adequate market solutions do not develop in a timely manner.

RTEP04 Conclusions

Reliability, while important everywhere, is a serious concern in the load pockets of Boston, Northwest Vermont, and the State of Connecticut. In particular, the load pocket of Southwestern Connecticut is at a critical stage and requires ISO New England to take emergency measures to maintain reliable electric supply during periods of high demand. Reliability is at risk in load pockets due to a number of factors, including:

[2] Load, or demand, is the amount of electric power required or drawn by electricity users from a power system at any given point in time. A load pocket is an area with limited import capability and/or a lack of local generation to support the load, or demand.

- Continued growth in electricity use
- Generating unit retirements
- Continued transmission bottlenecks,
- Inadequate development of new resources (i.e., new or repowered generation and demand-response programs)

Resource reliability could also become a major system-wide issue for New England in two to four years, especially if the region continues to experience the factors noted above. Moreover, heavy reliance on natural gas-fired generators that are subject to interruptions of fuel supply poses potential reliability issues for the winter peak-load periods.

Timely completion of transmission projects is critical to preserving and improving reliability region-wide and is key to solving reliability problems in load pockets. Siting or construction delays of critical 345 kilovolt (kV) projects will exacerbate reliability problems, particularly in load pockets, as there is only a limited window of opportunity to repower or redevelop existing generating units in these areas.

Implementing the actions identified in RTEP04, including continued enhancements of infrastructure and market design, will address New England's reliability concerns.

Key RTEP04 Findings

RTEP04 is ISO New England's most comprehensive effort to provide a plan for ensuring system reliability and promoting market efficiency. Major issues addressed include generating resource sufficiency and types needed, transmission adequacy, inter-area coordination, economic issues, and distributed resources. The following are the key findings of the RTEP04 report.

Reliability of Load Pockets

RTEP04 analyzes whether sufficient generating resources are available to meet both peak demand and reserve requirements necessary for system reliability. Results support the need to address serious resource deficiencies in the load pockets of Southwestern Connecticut, the State of Connecticut, Boston, and Northwest Vermont. The major concerns in these areas are continued load growth, potential retirement of several generating units, limited transmission capability into those areas, and limited amounts of planned alternative resources.

Southwestern Connecticut is the most critical load pocket in New England, with current resource deficits that will continue until Phase I of the Southwest Connecticut Reliability Project[3] is in service. ISO New England addresses the current deficit by using resources acquired from the Request for

[3] Detailed transmission projects are defined in Section 14 of the RTEP04 Technical Report.

Proposal (RFP) for Southwest Connecticut Emergency Capability[4]. Similarly, the State of Connecticut is resource-tight now and has to rely on emergency actions when there is insufficient capacity to meet demand. This situation is far from the accepted norms of system planning. Unfortunately, this circumstance will continue until the Southern New England Reinforcement Project is in service, which is currently planned for 2008.

Today, Boston has a margin of capacity; however, approximately 1,300 megawatts (MW) of generation has applied for deactivation or retirement, which has been approved for approximately 220 MW by ISO New England. The completion of two key transmission projects, the NSTAR 345 kV Transmission Reliability Project and the North Shore upgrades, currently scheduled for 2005–2008, will improve the Boston Import capability by providing access to additional regional resources.

Each of these load pockets requires the timely completion of major 345 kV transmission upgrades to reliably serve load and allow the development of new resources. If these transmission projects are not completed, bulk power system reliability will suffer. However, even with planned transmission upgrades, additional resources or repowering of existing resources will be needed within the load pockets to offset potential retirements and meet growing demand. Therefore, ISO New England is creating additional market incentives to promote the development of new resources in the load pockets, including a Locational Installed Capacity[5] (LICAP) market and Ancillary Services[6] markets that reflects the need for operating reserves by location.

System-wide Resource Reliability

Currently, the most critical reliability issues in New England are in the load pockets, while the overall regional system has surplus capacity. However, this surplus is expected to be short-lived as electricity use continues to grow. The New England supply outlook shifts from tight to deficit conditions over the next two to four years.

New England has come to the end of its building boom for new power supply sources. Moreover, some existing generating units needed for system reliability are in jeopardy. There is a potential for over 1,600 megawatts of generator deactivations or retirements. Several of these generating units are located in critical load pockets. Attrition is largely due to age, increased environmental compliance requirements, economic or financial considerations, or a combination of these factors. ISO New England is addressing capacity shortfalls in part through market enhancements, including LICAP and Ancillary Services markets, coupled with emergency actions if needed.

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[4] The RFP for Southwest Connecticut Emergency Capability secured resources that will provide approximately 125 MW of additional capacity beginning June 1, 2004, and up to 255 MW by the summer of 2007 from demand response resources, including both emergency generation and reductions in electricity use, and from conservation resources. The agreements obtained through the RFP are intended to help fill a reliability gap until a long-term solution to Southwest Connecticut's reliability problem is in place.

[5] Locational ICAP is a market that promotes reliability in New England by appropriately valuing capacity located in areas with limited access to power supplies and encourages investment in new infrastructure where it is needed within the New England region.

[6] Ancillary Service markets provide incentives for investment in operating reserve capacity, such as quick-start generation.

In addition, New England's high dependence on gas-fired generation poses a major risk to ensuring adequate generating unit availability during the winter period, as demonstrated by study results and experience during the January 2004 Cold Snap.[7] More than 9,500 MW of capacity, nearly all gas-fired, have been added in the region since 1999. New England now has approximately 11,540 MW of gas-capable capacity (units that use gas as the primary fuel), of which more than 6,730 MW relies solely on gas ("gas-only" sources). This leaves the region vulnerable to perturbations in gas supply, including price fluctuations, delivery constraints, and competition from other uses, such as home heating. RTEP04 results show that Boston, Southwestern Connecticut, and Central Massachusetts/Northeast Massachusetts are the areas most vulnerable to generation shortages resulting from natural gas fuel supply and delivery interruptions. Recent ISO New England actions will make additional capacity available during the winter and improve the reliability situation.

Transmission Projects

The transmission projects described in RTEP04 are needed to maintain bulk power system reliability or to improve wholesale electricity market efficiency. As the system continues to evolve, the need for transmission projects is reevaluated.

RTEP04 includes 246 regulated transmission projects throughout New England, with a total cost ranging from $1.5 billion to $3.0 billion over the next ten years. The actual costs will depend on the final design of the upgrades. Thirty-nine of the 246 projects are new to this year's plan. Since the publication of RTEP03, 25 projects have been completed.

The timing of key transmission projects serving the load pockets is critical to ensure system reliability and to allow sufficient time to repower existing generation sites or to develop new resources. These projects include the:

- Southwest Connecticut Reliability Project
- Southern New England Reinforcement Project
- NSTAR 345-kV Transmission Reliability Project
- Northwest Vermont Reliability Project

In addition to addressing critical projects within New England, RTEP04 also addresses an interconnection project with the New Brunswick Control Area. The Northeast Reliability Interconnect Project will provide additional opportunities for capacity and energy diversity exchange with New Brunswick, improved reliability of the transmission system, reduced transmission losses, and lessened dependence on complex special protection systems.

[7] The bitter cold temperatures during January 14–6, 2004, put a tremendous amount of stress on New England's electricity and natural gas systems. Constraints on the natural gas pipelines had an impact on the ability of gas-fired generators to operate. ISO New England's report on the Cold Snap can be found on its website at http://www.iso-ne.com/special_studies/

Inter-Area Planning/Coordination

Coordination of inter-regional planning is essential to ensure long-term reliability of the interconnected power system and enhance market efficiency. Improved coordination has been achieved through participation in the NERC, Northeast Power Coordinating Council (NPCC) and interactions with neighboring Control Areas.

Additionally, ISO New England, New York ISO, and PJM Interconnection have signed a Protocol that provides a structure to develop inter-area plans and improve overall coordination of planning among the Control Areas. Independent Electricity Market Operator, Hydro-Québec TransÉnergie, and New Brunswick will also participate in the inter-area coordination of planning activities. Initiation of a Northeastern Coordinated System Plan is scheduled for the fall of 2004.

Economic Assessments

The development and implementation of an improved capacity market structure aimed at appropriately valuing resources is essential to maintaining and improving reliability system-wide—particularly in Southwestern Connecticut, the State of Connecticut, and Boston—and to improving wholesale electricity market efficiency. RTEP04 provides historical market information and economic assessments of the future system, as well as the amount, general location, and timing of resources required for these areas.

Distributed Resources[8] and Renewable Portfolio Standards

Distributed resources can play an important role in fostering both system reliability and market efficiency.

While Maine has excess renewable[9] resources to meet its Renewable Portfolio Standard (RPS), Connecticut, Massachusetts, and Rhode Island will require growth in renewable resources. Current plans for renewable projects within New England appear, as a whole, insufficient to meet the projected RPS requirements for 2010.

Required Actions

The following key actions, encompassing improvements in infrastructure and processes, are required to ensure system reliability and promote market efficiency over the next ten years.

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8 Distributed resources include demand-response and distributed generation. Demand response is the reduction in electricity consumption in response to high real-time wholesale electricity prices or stress on the reliability of the electricity grid. Distributed generation consists of small generators located near or within customer-consumption points.

9 Renewable resources are energy sources that are replenishable by natural forces. They typically include solar energy, wind power, ocean thermal, tidal power, and biomass fuels. States use slightly different definitions for RPS purposes.

Infrastructure

- Pursue the transmission projects identified in RTEP04, including the Southwest Connecticut Reliability Project, Southern New England Reinforcement Project, NSTAR 345-kV Transmission Reliability Project, Northwest Vermont Reliability Project, and the Northeast Reliability Interconnect Project.

Processes

- Monitor the reliability situation, especially in load pockets. Continue to implement necessary emergency actions and encourage development of new generating and demand-side resources.

- Provide market incentives and promote federal and state policies to encourage the development of resources in load pockets. These market reforms include the development of a LICAP market and the implementation of Ancillary Services markets that reflect the need for operating reserves by location. Market reforms need properly to value properly the ability to provide energy when needed and thereby provide incentives for the development and utilization of dual-fuel capability of existing, new, or repowered generation, and of distributed and renewable resources.

- Examine new methodologies, tools, and market improvements to enhance system reliability and market efficiency. This includes enhancing the methods currently used to calculate resource requirements (Objective Capability) to better consider operational reliability.

- Mitigate, prior to the winter of 2004/2005, reliability concerns regarding over-reliance on gas-fired units by:

    - Establishing an ISO/Gas Pipeline Operations Committee to improve near-term operations planning and coordination of maintenance of both the electric and gas pipeline systems in anticipation of cold snap conditions. Communication protocols will be consistent with the NEPOOL Information Policy.
    - Developing a new Operating Procedure for Cold Snap periods. Such a procedure would trigger:
        - Eliminating or canceling "Economic Outages;"
        - Switching dual-fueled units to alternative fuels on a timely basis
        - Modifying unit commitment processes to enhance coordination between the electric and gas market nomination timelines.

These actions are expected to improve the availability of gas units by up to 2,000 MW compared to the 2004 Cold Snap experience.

Implement the Northeast Planning Protocol. This includes issuing a joint Northeast Inter-Area System Plan in 2005 and coordinating the planning of generation interconnections near Control Area borders.

The major highlights of the RTEP04 study are discussed above. More detailed information is presented in the *RTEP04 Summary Report* and the *RTEP04 Technical Report*.

An open stakeholder process provided invaluable input to RTEP04. The Transmission Expansion Advisory Committee (TEAC) is composed of a wide variety of representatives from the electric power industry, natural gas industry, and regulatory agencies. ISO New England appreciates the continued support by stakeholders in the RTEP process and welcomes any suggestions or comments.

C. NEW BRUNSWICK POWER

MARITIMES AREA INTERIM REVIEW OF TRANSMISSION RELIABILITY (2004–2009)

INTRODUCTION

The most recent Comprehensive NPCC Review of the New Brunswick Power transmission system was completed in March 2002, and covered the period from 2001 through 2006. In 2003, NB Power presented an Intermediate Review, which focused on the assessment of the impact of the new Memramcook 345/138-kV Terminal and the planned second 345-Kv Tie between New Brunswick and New England and covered the period from 2003 to 2008. This year's Interim Review summarizes the changes in New Brunswick facilities, plans, and forecasted loads up to 2008/2009.

CHANGES IN FACILITIES AND SYSTEM CONDITIONS

Table 1 provides a comparison of load forecasts, generation resources, and transmission facilities used in the Comprehensive Review of 2002, the Intermediate Review of 2003, and this Interim Review.

Load Forecast

In the latest Comprehensive Review, completed in 2002, the in province Winter Peak load forecast (firm + non-firm) for year 2006 was 3026 MW. This was based on the 2001 load forecast. In the most recent Intermediate Review, completed in 2003, the load forecast showed a slight load growth (3164 MW for 2007/8 Winter Peak). The most recent load forecast (May 2004) predicts a peak demand in 2008/2009 of 3345 MW (3210 MW firm and 144 MW non-firm).

Generation Resources

Table 1 shows a slight increase in the installed capacity, from 3987 MW, which was reported in the latest Intermediate Review, to 4017 MW. The change is the result of new non-utility combustion cogeneration at Grandview, in Saint John area. The total net capacity of the two units at Grandview is 90 MW, with in-service date of 2004/2005. Also, a 20-MW Wind Farm on Grand Manan Island has been recently approved with a planned in-service date of 2005/2006 as a first phase of a 100-MW target of renewable energy sources by 2010.

However, due to the nature of wind generation, the 20 MW at Grand Manan will not be included in the calculation of the installed capacity of NB Power. The System Impact Studies of Grandview generation, and the Grand Manan Wind Farm, have shown no significant adverse impact on the Interconnected Bulk Power System.

In the last Interim Review, it was reported that conversion of Coleson Cove Plant from oil to Orimulsion® is planned for 2004/2005. However, based in most recent information about fuel availability, the plant could continue to use oil, until alternative fuel options, including Orimulsion®, are secured. Therefore, at this time there is no change in the installed capacity of Coleson Cove Plant.

The shut down for refurbishment of Point Lepreau nuclear station (640 MW) is now planned for April 2008, lasting about 18 months. During the outage of Point Lepreau station, the 20% reserve requirement will be met by reducing the external sales and/or purchase from outside Area(s).

Transmission Facilities

In-Province Transmission

As shown in Table 1, there are no major changes foreseen in the provincial bulk transmission facilities between now and year 2009, other than local reinforcements. These are namely installing a 345/138-kV tie transformer at Memramcook (in-service in August, 2004) and a 345/230-kV tie transformer at Newcastle in 2006/2007. The Newcastle transformer was included in the latest Comprehensive Review, while the Memramcook 345/138-kV Terminal has been addressed in last year's Intermediate Transmission Review. Also a second 345/138-kV Transformer at Edmundston, in northwest New Brunswick, to be connected in parallel with the existing one, is planned in 2005/2006, to meet local load growth.

Interconnections

The second 345-kV transmission line from Point Lepreau, New Brunswick to Orrington, Maine, has been addressed in the latest Intermediate Review. The planned in-service date for the second tie is 2006/2007. The project has received 18.4 approval in New England and as well as the National Energy Board approval in Canada.

Special Protection Systems

As indicated in the latest Intermediate Review, the changes at Memramcook Terminal resulted in split of the existing 345-kV line between Salisbury-Onslow into two sections, therefore modification to the existing Type I SPS were required. The changes have been made, and the details of the modification have been presented and approved by the various NPCC Task Forces and RCC in 2003. The second NB-NE tie will also require changes to New Brunswick SPS's that are presently associated with the existing NB-NE 345-kV tie. The design details are being finalized and will be submitted to NPCC for review and approval.

Dynamic Control Systems

There are no new Dynamic Control Systems (DCSs), other than the Brushless Exciters associated with the two new Grandview units, which have been classified as Type 3 (i.e., local impact only). Therefore, all existing and planned DCSs in New Brunswick have only local area impact and are not expected to change between now and the year 2009.

Short Circuit Assessment

It is New Brunswick's practice to regularly conduct both transient and sub-transient Short-Circuit Studies for the present and the future systems. Short-Circuit analysis is also a part of any System Impact Study for a new facility or a request for a new Transmission Service. System Impact Studies of the facilities included in this Interim Review indicate that there is no significant change in the Short-Circuit level of the Bulk Power Systems of NB Power or the neighboring systems. However, the studies have shown that there is a need to upgrade the non-bulk 69-kV Breakers in the local Saint John area as well as 138-kv breakers in the Moncton area. All of the breaker upgrades have been completed except for the two in Moncton planned for 2005.

IMPACT ASSESSMENT AND OVERVIEW SUMMARY

New Brunswick forecast and plans for the period from 2004 through 2009 have been discussed in this Interim Transmission Review. The conclusion of this Interim Review is that the forecast changes in the Bulk Power Transmission system of New Brunswick for the period reported from 2004 to 2009 are not significant enough to necessitate a more detailed Comprehensive or Intermediate Review. Therefore, NB Power is judged to be in conformance with the NPCC *Basic Criteria for Design and Operation of the Interconnected Power Systems*"

TABLE 1
Comparison between the Study Conditions of the 2002 Comprehensive Review, the 2003 Intermediate Review and the Current Interim Review

	2002 Comprehensive Review (2001 through to 2006)	**2003 Intermediate Review (2003 though 2008)**	**2004 Interim Review (2004 though 2009)**
Basis for Load Forecast	**2001 Forecast**	**2003 Forecast**	**2004 Forecast**
• In-Province Load • Firm Load • Operable Generation Capacity (Existing & Planned Changes) • Capacity Sales Agreements • Margin Based on net Capacity & Firm Load	3026 MW 2873 MW 4021 MW 250 MW 31%	3164 MW 3020 MW 3987 MW 250 MW 24%	3345 MW 3201 MW 4077 MW (*) 250 MW 20%
Generation Changes (from the Previous Review)	• Repowering of Courtenay Bay #3: from 99 to 283 MW by June 2001 Retiring G.Lake, C. Bay #1 & #2 and sale of two Millbank units (total lost capacity = 313 MW) Independent Power Producer's (IPP): 47.5 MW (25 MW Cancelled). (Lantic Sugar Closed 1.5 MW)	• Temporary shut down of Point Lepreau (635 MW) for refurbishment, has been deferred to 2008/9 time frame. • De-rating Coleson Cove Plant after Orimulsion® conversion by about 21 MW (2004/5).	• Planned shut down of Point Lepreau (635 MW) for refurbishment in April 2008. • New 2x45-MW units at Grandview, 2004/5. • 20-MW wind farm at Grand Manan, 2005/6. (as a apart of 100 MW of renewable energy sources by 2010)
In-Province Transmission Facilities	• New Memramcook 345/138kV Terminal by 2003, for local area support. (Not included in 2002 Comprehensive Review because final configuration and size were under review/study) • Addition, in 2001/02 of some 138kV sub-transmission lines for local area support. • Newcastle 345/230kV terminal planned for 2004.	• The System Impact Study for Memramcook 345/138 kV terminal has been completed. Modification to Type I SPS#106 is required. Target date was the Fall of 2003. • Newcastle 345/230kV terminal planned for 2005.	• Completion date for Memramcook August 2004. • Modification to Type I SPS#106 has been approved by NPCC 2003. • 2nd 345/138kV transformer at Edmundston planned for 2005/6. • Newcastle 345/230kV terminal (Now planned for 2006/7)
Inter-Area Transmission: 2nd NB-NE 345kV Tie	• Modelled in 1989 Comprehensive Review. • Not considered in the 2002 Review.	• The System Impact Study for the 2nd NB-NE 345kV i.e. (*planned in-service in 2006)*, has been completed. System reinforcements and changes to SPS's are required.	• Planned in-service date is 2006. • SPS design details, once completed, will be submitted to NPCC for approval.

(*) This capacity number includes the under construction 90 MW at Grandview, in-service date 2004/5. During the refurbishing of Point Lepreau, the operable capacity would be less than shown by 640 MW and will be replaced by purchases from interconnections to meet the 20% reserve requirement.

D. NEW YORK INDEPENDENT SYSTEM OPERATOR

ELECTRIC SYSTEM PLANNING PROCESS: INITIAL PLANNING REPORT (Approved by NYISO MC October 14, 2004)

Executive Summary

Introduction

The NYISO Initial Planning Process is the first phase in the development of a comprehensive planning process for the NYISO. It forms the foundation for the comprehensive process. The Initial Planning Process focuses on:

- The consolidation of the existing NYISO reliability-based analyses
- An extension of reliability analyses for an additional 5 years to cover a 10-year period (2004 – 2013)
- The addition of reliability scenario analyses to the base case conditions

In addition, the Initial Planning Process includes an accounting of historical congestion costs, as defined by the stakeholders, and an analysis of the causes of historic congestion in order to provide more complete information to the marketplace to assist in future decision making.

In general, electricity deregulation in New York State and, for the most part, the northeast quadrant of the United States, has led to the unbundling of generation and transmission development. Largely gone are the days of planning in which generation and transmission plans were highly coordinated. In today's world, the reliability of the power system is ensured by a combination of resources provided by market forces and regulated wires companies. The purpose of this electric system expansion plan is to determine whether the electric system resources, provided by a combination of market forces and regulated entities, is providing sufficient resources to ensure the reliability of the New York State bulk power system is maintained throughout the ten-year planning horizon. In addition, scenario analysis will be conducted to identify any opportunities or risk that should be monitored by the NYISO upcoming Comprehensive Planning Process.

This report is the first electric system planning report prepared by the New York Independent System Operator (NYISO). This initial planning document represents the first in a series of annual electric systems plans designed to ensure that the reliability of the New York State bulk power system is maintained. The "Initial Planning Report" (IPR) is very similar in nature to the "Long-Term Reliability Assessment" published annually by the North American Electric Reliability Council (NERC), which provides an assessment of the reliability of the bulk electric systems in North America. Besides being New York centric, the initial planning report presents more detail and is supported by an extensive amount of power-system simulations to assess whether the New York bulk power system can maintain both resource and transmission adequacy under various scenarios. The report presents results for the reliability assessments that were conducted, as well as a reporting of historical congestion cost.

Reliability Needs Assessment

For the base case, the reliability needs assessment (RNA) concluded that the planned system met all reliability criteria over the ten-year study period. However, under certain scenarios, the initial planning assessment identified potential risk to reliability that will need to be monitored on going forward basis – i.e., in the comprehensive reliability planning process. The potential risks to reliability identified in the assessment under various scenarios were as follows:

- Additional resources beyond those currently under construction will need to be committed to the Long Island and New York load pockets in order to maintain resource adequacy criteria beyond 2006 and 2008, respectively. These resources could either be in the form of generation or transmission capability or a combination thereof.

- Unit retirements, increased transfers, and/or higher-than-expected load growth can all result in insufficient reactive capability to maintain proper system operating voltages, and potentially could place the system at higher risk of voltage collapse in years 6–10 of the study period.

- The initial planning process identified 1,600 MW of announced generating capacity retirements in the NYCA through 2008. Many factors, such as more restrictive emission requirements which results in the economic obsolescence of a facility, could result in additional retirements. The reliability impacts of retirements need to be evaluated, at a minimum, from voltage- and locational-capacity perspective.

Although development of solutions to any reliability needs identified in the initial process were not part of the process, it will be noted that there are New York market participant and NYISO initiatives in process that will either address these potential risks directly or help mitigate them on going forward basis. They include:

The Long Island Power Authority and New York Power Authority will be contracting for additional resources for the critical Long Island and New York City load pockets to ensure resource adequacy is maintained. Also, in response to the August 14, 2003 blackout recommendations and concerns raised by its own internal studies, the NYISO has implemented a number of initiatives to improve its reactive planning and voltage support service capabilities. They are:

- NYISO Operations Engineering developed a number of studies and investigations to identify the key issues impacting the observed voltage performance of the New York bulk power system. The following specific issues are or have been addressed through these studies:

- Detailed review of recent system peak-load conditions and relationship of system load to EHV voltage profile

- Review of the NYISO Voltage Support Ancillary Service and the performance of VSS providers and reactive capability testing

- Update voltage transfer limits and modeling

- Draft Load Power Factor Assessment Summary and Status Report – August 2004

These investigations are currently under review by the System Operations Advisory Subcommittee.

- North American Electric Reliability Council blackout recommendation 7a: "reevaluate within one year the effectiveness of the existing reactive power and voltage reactive power and voltage control standards"

- North American Electric Reliability Council blackout recommendation 8b: "complete an evaluation of the feasibility and benefits of installing undervoltage load shedding capability in load centers".

These initiatives will result in important improvements for the New York Control Area reactive planning and voltage support service capabilities.

Historical Congestion Reporting

The primary objective of the analysis of historical congestion cost was three fold:

- To develop a definition or definitions of historical congestion costs;
- Develop a reporting process/tool for reporting historical congestion; and
- Develop a report of congestion cost for year 2003.

All these objectives were met and are documented in chapter 14 of the report.

In addition, the analysis of historical congestion cost resulted in the following observations:

- The flow of funds resulting from power system congestion is complex;
- An invaluable tool for analyzing congestion costs in the aggregate and by limiting transmission element has been developed; and
- While our understanding of the impact of congestion has been greatly enhanced, unwinding the cost and benefits of transmission upgrades from the perspective of congestion economics will be

difficult and complex. A major objective in the further development of the comprehensive planning process will be to refine and extend the analysis of congestion cost.

Conclusion

The initial planning process RNA concluded that for the base case the plan system met all reliability criteria. This fact not withstanding, electric system planning is an ongoing process of evaluating, monitoring and updating as conditions warrant. This initial planning report represents the first electric systems planning document produced by the NYISO. The primary objectives of the initial planning process were:

- To ensure that the reliability of the NY bulk power system is maintained
- To provide the NY wholesale electricity market informative and valuable information. Success will be measured by how well the market does in maintaining the reliability of the NY grid without having to resort to backstop or regulated measures

The next major step in the NYISO electric systems planning process will be the implementation of the comprehensive process.

E. PJM INTERCONNECTION, LLC.

2004 REGIONAL TRANSMISSION EXPANSION PLAN (Approved July, 2004)

EXECUTIVE SUMMARY

The continuing evolution and growth of PJM's robust and competitive regional markets rests on a foundation of bulk power system reliability, ensuring PJM's ongoing ability to meet control area load-serving obligations. PJM's FERC-approved Regional Transmission Expansion Planning Process ("RTEP Process") preserves this foundation through independent analysis and recommendation, supported by broad stakeholder input and approval by an independent RTO Board in order to produce a single Regional Transmission Expansion Plan ("RTEPlan").

The RTEP Process is driven by a number of planning perspectives and inputs, including the following:

- Mid-Atlantic Area Council (MAAC) Reliability Assessment
- East Central Area Reliability Council (ECAR) Reliability Assessment
- Mid-America Interconnected Network (MAIN) Reliability Assessment
- PJM Transmission Adequacy Assessment
- PJM Annual Report on Operations
- PJM Load Serving Entity (LSE) capacity plans
- Independent Power Producer (IPP) capacity plans
- Transmission Owner transmission plans
- Merchant Transmission developer plans
- Interregional transmission plans
- Firm Transmission Service Requests
- PJM Transmission Expansion Advisory Committee (TEAC) input

The cumulative effect of these drivers is analyzed through the RTEPProcess to develop a single RTEPlan which recommends specific transmission facility enhancements and expansion on a reliable, economic and environmentally acceptable basis.

These analyses are conducted on a continual basis, reflecting specific new customer needs as they are introduced, but also readjusting as customer needs change. As the process matures, it is expected that two successive regional plans will be developed and approved each year with one or more addendum issued in the interim to account for retirements to elements of the plan and the withdrawal of generation or merchant transmission projects from consideration.

In this way, the plan continually represents a reliable means to satisfy a wide range of customer needs in a fully integrated fashion, at the same time preserving the rights of all parties with respect to the transmission system. The assurance of a reliable transmission system and the protection of the customer rights with respect to that system coupled with the timely provision of information to stakeholders are the foundation principles of the PJM planning process.

PJM's most recent RTEPlan, presented here, recommends transmission enhancements to meet baseline network system needs over a 2003 through 2008 time frame and to meet the needs of over 100 proposed generation projects representing some 23,000 MW in PJM Generator Interconnection Queues A through K.

A summary of the RTEPlan as of December 2004 follows:

Baseline Network Reliability Upgrades	$574 Million
Merchant Transmission and Generation Network Upgrades	$466 Million
Total RTEPlan Transmission Enhancements	$1.040 Billion

Each RTEPlan encompasses a set of recommended "direct connection" transmission enhancements, a set of "network" transmission enhancements and the cost responsibility of each party involved. Each RTEPlan includes a spectrum of proposed power system enhancements: circuit breaker replacements to accommodate increased current duty cycles; new capacitors to increase reactive power support; new lines, line reconductoring and new transformers to accommodate increased power flows; and, other circuit reconfigurations to accommodate power system changes as revealed by the drivers discussed above.

Generator interconnection requests, while not the sole drivers of the RTEPProcess, are a key component of the RTEPlan. Analyzing these requests has required adoption of an approach that establishes baseline system improvements driven by known inputs, followed by separate generator interconnection queue-defined, cluster-based impact study analyses. Overall, PJM's RTEPProcess - under a FERC-approved RTO model - encompasses independent analysis, recommendation and approval to ensure that facility enhancements and cost responsibilities can be identified in a fair and non-discriminatory manner, free of any market sector's influence. All PJM market participants can be assured that the proposed regional plan was created on a level playing field.

F. HYDRO-QUEBEC TRANSENERGIE

Hydro-Québec TransÉnergie is presenting a revised version of the **QUEBEC AREA INTERIM REVIEW OF TRANSMISSION RELIABILITY (2004-2009)** which provides an assessment of the TransÉnergie planned system for this period to NPCC.

Introduction

The most recent Comprehensive NPCC review of Hydro-Québec TransÉnergie bulk power transmission system was completed in November 2001 and covered the period 2002-2007. In 2003, Hydro-Québec TransÉnergie presented an interim review, which summarized the changes that covered the period from 2003 to 2008. This year's Interim Review, presented in 2004, shows the changes in forecast conditions and planned transmission facilities for the period 2004-2009.

Comparison of Load Forecast, Resources and Transmission Facilities

A comparison of load forecast and generation resources between the last comprehensive review of 2002, the interim review of 2003 and the present interim review of 2004is given in the following sections.

Load Forecast

From the last comprehensive review, the peak demand forecast for year 2007 was 34,842 MW based on the 2001 forecast as compared to 35,781 MW for year 2007 based on the 2004 forecast, therefore an increase of 939 MW. Thus, based on the most recent peak load forecast for the year 2007, we are about 3.0 % higher than the case tested in the last Comprehensive Review.

This relative important correction in the forecast reflected an all-time winter peak demand of about 2,068 MW higher than the peak load forecasted for winter 2003-04, the internal peak load reached 36,268 MW on January 15, 2004 at 5h 30 p.m. This all-time peak was due to a long period of extremely cold weather conditions throughout the entire province of Québec. At that peak time, the system supported firm deliveries of 397 MW to neighboring networks outside Québec and imported over 1,000 MW.

Concerning the year 2009, we observed an annual load growth of only 0.8 % (295 MW) from year 2008 to year 2009 base on the 2004 forecast.

Generation Resources

The 2004 forecasted generation resources for year 2009 is 41,161 MW as compared to 40,299 MW for year 2007 in the 2003 forecast, resulting in an increase and correction of 862 MW in resources.

Except for some re-ratings of existing generation facilities of about an additional 31 MW, the only committed new generations are the addition of Rapide des Coeurs (70 MW for 2008) and Chute Allard (57 MW for 2008) hydro power plants. New resources from two IPP for a total of 33 MW are also planned (two biomass generations of 17 MW in 2008 and 16 MW in 2007). Also the Peribonka power plant (340 MW) has been delayed to 2008. Moreover, other resources such as the following are not yet committed.

As mentioned in the precedent interim review, Hydro-Québec Distribution did a Call for tenders for an additional 1000 MW of wind generation beginning in 2006 for 200 MW, 100 MW in 2007, and 150 MW in 2008 and the remaining amount up to 2012. These wind generations will be located in the non-bulk Gaspésie area. It is also the intention of the Hydro-Québec Distribution to make additional Calls for tenders for 800 MW of co-generation. A volume of 350 MW is planned to be in service for 2008 and 2009. There is also a potential of a 400 MW of Calls for tender for dispatchable generation to be in service in the same time frame. The impact studies for these new generations have not been done yet and these new resources are not included in the total generation resources for 2009 mentioned earlier. .

Transmission Facilities

New transmission facilities that were not included in the last interim review are required for the integration of the new two hydro plants Rapide des Coeurs and Chute Allard. To integrate these new generations to the main system 65 km of 230 kV circuit line will be added and because of the low inertia of these units, 40% of series compensation is required at the non-bulk Des Hetres substation. Finally, for the re-powered of Outardes-3 only the replacement of the four step-up transformers are required for an in service in 2007. The impact studies for these new generations demonstrated that no reinforcement of the main transmission network is required to meet the Hydro-Québec TransÉnergie and NPCC transmission design criteria.

Moreover, these following transmission projects have been proposed following the 1998 ice storm:

- The installation of semi-conductor devices at the Lévis (approved by the Régie de l'énergie) and Boucherville 735 kV substations, planned respectively for 2006 and 2007, which will be normally operated as a dynamic shunt compensators on steady-state basis with a capabilities of 250 MVAR / -125 MVAR. In the event of severe icing conditions, these devices will be transformed to sequentially allow the injection of high DC current in 735 kV and 315 kV lines to melt the accumulated ice on conductors;

- Increasing the mechanical robustness of existing tower to improve the ice loading on more than 380 km of existing 735 kV lines and 183 km of 315 kV lines, planned in 2006 (approved by the Régie de l'énergie) and 325 km of existing 735 kV lines planned in 2007.

As mentioned earlier, in the past years we encountered several times an all-time peak load as a result that we integrated a new system condition in our transmission design criteria. This new system condition reflect an extreme weather condition that result in about 11 % of additional load over the Hydro-Québec winter peak load (about 4 000 MW). To meet this new requirement in our transmission design criteria additional shunt capacitors will be install at these locations for December 2004:

- Hertel substation 345 MVAR at 315 kV;
- Duvernay substation 345 MVAR at 315 kV;
- Boucherville substation 2 X 245 MVAR at 230 kV.

This new requirement requires also an additional shunt capacitor at the Duvernay substation (345 MVAR at 315 kV) for the integration of the Eastmain 1 power plant that was not mentioned on the precedent interim review.

Impact Assessment and Overview Summary

The 2007 Québec Area Comprehensive Review performed in 2001 had demonstrated that the system as planned for year 2007 is in full conformance with NPCC criteria for design and operation.

TransÉnergie is planning to reinforce its transmission system by the addition of new equipments to insure full delivery of new resources. However, the integration of these new generations will not significantly increase the flow on the transmission corridors. System studies and fault level studies have been conducted by TransÉnergie to assess the impact on the system performance of the bulk power system. The system studies have concluded that there was sufficient transmission margin with the existing system to permit this additional flow and the fault current level analysis required the replacement of some breakers. A new requirement in the design of the TransÉnergie bulk transmission system will also ensure capability of the system to withstand severe weather conditions up to 11 % over the normal peak forecasted load.

In summary, while the 2008/2009 system includes system additions not covered in the last 2002 Reliability Review, this interim review indicates that the proposed additions improve the capability of the system without significant changes in power transfers. The addition of new generation in 2009 was assessed by and concluded that the 2009 system is in full conformance with the NPCC *Basic Criteria for Design and Operation of the interconnected system*.

IV. NPCC/MAAC ACTIVITIES

This section provides an overview of the NPCC and MAAC Regional Councils. See Appendix C for a more detailed description of the existing NPCC regional planning activities and Appendix D for information on inter-regional planning activities that extend beyond the NPCC and MAAC regions.

A. NORTHEAST POWER COORDINATING COUNCIL ("NPCC")

NPCC is the regional entity responsible for coordinating the reliability of the bulk power system in the Northeastern United States and Eastern Canada. Reliability is achieved through the establishment of reliability criteria, coordination of system planning and operations, and monitoring and assessment of compliance with such reliability criteria. In the development of reliability criteria, NPCC, to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

NPCC is one of the ten regional reliability organizations that make up the membership of the NERC. NPCC is an international, voluntary, non-profit organization. Its membership is diverse. It includes electric utilities, transmission owners/providers, non-utility generators, power marketers, transmission customers, Independent System Operators ("ISOs"), the New York State Reliability Council, an Independent Electricity Syetem Operator, and provincial and state authorities.

The geographic area covered by NPCC includes New York, the six New England states, Ontario, Quebec, and the Maritime Provinces. The total population served by NPCC's members is approximately 54 million. The area covered is approximately 1 million square miles. NPCC is the third largest of the ten Reliability Councils, which together comprise NERC. With a projected 2004 coincident peak demand of over 104,500 MW, NPCC effectively coordinates the operations of five contiguous control areas: New York, New England, Ontario, Quebec and the Maritimes. Together the load in New York and New England represents over 8% of the total load in the United States and the provincial load within NPCC represents approximately 70% of the total Canadian load. Electric service to the major metropolitan load centers of New York City, Boston, Toronto and Montreal is provided via a highly interconnected bulk power system totaling over 35,000 miles with interconnections to the MAAC, East Central Area Reliability Coordination Agreement (ECAR) and Mid-Continent Area Power Pool (MAPP) NERC Regions.

The NPCC *Membership Agreement* provides for open, inclusive membership and fair and nondiscriminatory governance. Full membership is available to all entities that participate in the interconnected electricity market in Northeastern North America. Two voting classes exist, each consisting of several sectors. Full Members are classified as either Transmission Providers or Transmission Customers and have one vote within their voting class. Through this non-discriminatory governance structure NPCC precludes the possibility of either voting class exercising undue control.

The *Membership Agreement* also allows for non-voting membership to be extended to regulatory agencies with jurisdiction over participants in the electricity market in Northeastern North America. It also extends membership to public interest organizations expressing interest in the reliability of electric service in Northeastern North America.

The Blackout of 2003 highlighted the importance of the reliability of the interconnected electric systems in North America. A lesson learned from the post-blackout investigations is that all segments of the electric industry, working in concert, share a role in providing bulk power system reliability. The NPCC Regional Council performs the reliability assurance role in a coordinated and efficient manner.

The reliability assurance functions and services currently performed by NPCC are divided into five broad categories: Development of Regionally-Specific Reliability Criteria, Compliance Monitoring and Enforcement, Coordination of Operation, Coordination of Planning, and Inter-regional Coordination.

These functions and services represent those aspects of reliability management that the membership of NPCC judged to be both efficient and appropriate to perform at a regional level. The existing NPCC structure and processes help ensure system reliability within NPCC and beyond the regional boundaries. The NPCC Committees oversee the actions of the NPCC Task Forces. The NPCC Task Forces that have the primary responsibilities for conducting the work needed to ensure system reliability.

The following is an overview of how NPCC's organizational structure, interrelationships, coordination and reliability- provide wide area, regional and inter-regional support.

Development of Regionally-Specific Reliability Criteria

NPCC has developed its own set of Regionally Specific Reliability Criteria. These Criteria are in all cases not inconsistent with and in many cases more stringent that North American Reliability Council (NERC) Planning Standards and Operating Policies. These Regionally Specific Criteria have been developed through NPCC's Open Process which is transparent, open and inclusive utilizing web based tools and encourages industry input as well as neighboring Regional Council comment-during the development and revision process. Regional reliability requirements, infrastructure, and bulk power system disturbances are analyzed to assess need for more stringent or additional criteria.

NPCC develops its criteria assuring that the criteria are neither inconsistent with, nor less stringent than, NERC continent-wide Reliability Standards, and are not anti-competitive in nature and conducts regular, periodic reviews of regionally-specific criteria, guidelines and procedures; currently there are 9 criteria, 12 guidelines and 21 procedures.

NPCC established (and regularly reviews) the Bulk Power System Definition and identifies the elements of the Bulk Power System.

NPCC also participates in NERC Reliability Standards Development process, and coordinates ballot body segments within its geographical area.

Compliance Monitoring and Enforcement

Enforcing compliance within NPCC of reliability standards is also a major part of NPCC's role in maintaining reliability. Compliance with Reliability Standards includes on-going participation in the development and modification of standards and procedures plus the implementation and enforcement of this process. The NPCC Reliability Compliance and Enforcement Program is used to assess and enforce compliance with NPCC reliability criteria. Actions taken by NPCC under the Program, including the imposition of sanctions, where applicable, shall in no way be construed as an acceptable alternative to the Member's continued obligation to comply with NPCC Criteria, Guides and Procedures. The Program is designed to be consistent with the concept that compliance assessment and enforcement is most effectively accomplished by the entities that are closest to the complying party. The Program establishes the following assessment structure: NPCC assesses and enforces compliance to those standards and criteria for which the Areas have the reporting responsibilities, and the Areas assess and enforce compliance to those standards and criteria for which the market participants have reporting responsibilities.

Coordination of Operation

The NPCC Task Force on Coordination of Operation promotes, and provides a forum for, the active coordination of security and operation among the NPCC control areas and neighboring NERC regions to enhance the reliability of the interconnected bulk power system. Responsibilities of the Task Force include:

- Coordination of the development of operating policies and guidelines affecting the security and operability of interconnected systems in coordination with NERC;
- Conducting seasonal reviews of the overall reliability of the generation and transmission systems in NPCC; Reviewing the operational readiness of NPCC and recommending possible actions to mitigate any potential problems identified for the coming operating period;
- Enhancing the effectiveness of NPCC operations;
- Conducting inter-Area and inter-regional studies to enhance reliability and operational effectiveness through the development of common operating policies and guidelines, on such matters as: inter-Area operations, the derivation, application, and interpretation of operating limits, operating reserve criteria, recovery to a secure state following contingencies, the basic principles of operator procedures in emergencies as they affect inter-Area security; and,
- Ensuring coordination of operating matters with other Regions.

The Task Force on System Protection ("TFSP") promotes the reliable and efficient operation of the interconnected bulk power systems through the establishment of criteria and guidelines, and coordination of design, relative to the protection associated with the bulk power systems. Responsibilities of the Task Force on System Protection related to maintaining reliability include:

- Monitoring compliance with the *Maintenance Criteria for Bulk Power System Protection* (Document A-4);

- Monitoring compliance with the requirements of the automatic load shedding program as specified in the *Emergency Operation Criteria* (Document A-3)
;
- Conducting an annual update of the special protection systems listing in cooperation with the Task Force on System Studies;

- Reviewing and analyzing the performance of protection systems following selected major power system disturbances and events; assessing proposed protection systems, including special protection systems, in accordance with the *Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System* (Document C-22); and, Reporting on the findings with respect to compliance with the NPCC *Bulk Power System Protection Criteria* (Document A-5); providing technical advice on protection issues to the Compliance Monitoring and Assessment Subcommittee (CMAS) and any other NPCC group as required.

Coordination of Planning

The NPCC Task Force on Coordination of Planning promotes bulk power system reliability through the coordination of NPCC Area system planning and expansion processes and activities. Responsibilities of the Task Force include:

- Initiating reviews of the Basic Criteria for the *Design and Operation of Interconnected Power Systems* (Document A-2); other NPCC criteria, guidelines, and procedures related to planning; and documents that provide for the uniform implementation, interpretation, and monitoring of compliance with criteria, guidelines, and procedures related to planning;

- Reviewing the adequacy of the NPCC systems to supply load, considering forecast demand, installed and planned supply and demand resources, and required reserve margins in accordance with *Guidelines for Area Review of Resource Adequacy* (Document B-8)

An example of a Study initiated by the Task Force on Coordination Planning is the Collaborative Planning Study (CP-10), which involves neighboring NPCC Areas and neighboring Regions. The study identified system impacts affecting other Areas or Regions, utilizing probabilistic and deterministic study tools. (This report can be found on the NPCC website at the following address: http://www.npcc.org/publicFiles/documents/collaborative_Planning_Initiative_Phase_2.pdf)

The NPCC Task Force on System Studies also has a major role in promoting bulk power system reliability through system planning and expansion. This Task Force has responsibility for:

- Coordinating the review of the compliance of future Area plans with the *Basic Criteria* including an analysis of resource and transmission system additions, and the potential active overall coordination of system studies of the reliability of the interconnected bulk power system and for the review of certain NPCC documents;

- Participating with the other Task Forces in reviews of the "*Basic Criteria for the Design and Operation of Interconnected Power Systems*" and other NPCC criteria, guidelines, procedures and documents which provide for the uniform implementation, interpretation and monitoring of conformance to criteria, guidelines and procedures related to planning;

- Conducting Area Reviews, in accordance with the "*Guidelines for NPCC Area Transmission Reviews*" which assess the impact of planned transmission and resource additions or modifications, on system reliability and which determine the Area's conformance with the *Basic Criteria*;

- Performing such load flow, transient stability, and other studies as required to analyze the overall long term reliability of the planned bulk power transmission system of NPCC and the interconnections between NPCC and other regional councils including analysis of potential inter-Area effects of special protection systems;

- Conducting analytical studies appropriate to the coordination of system planning and system protection in NPCC; maintaining a library of load flow base cases and associated dynamics data, for use in Area Reviews and overall NPCC Region transmission assessments; participating in ad hoc reviews of specific projects; reviewing major system disturbances to ascertain the adequacy of the interconnected system; identifying and recommending improved system study techniques; and,

- Reviewing the adequacy of the automatic and manual under frequency load shedding programs.

Inter-regional Coordination

Through NPCC, its members participate in various reliability-related activities that involve the other NPCC Areas, neighboring Regions and NERC. This includes participation in MAAC-ECAR-NPCC ("MEN") system studies and a large number of NERC activities.

The MEN Study Committee conducts the necessary periodic analyses and reviews of generation and transmission expansion programs over the large MEN Areas. The MEN Study Committee has the responsibility for conducting the studies needed to assess the reliability of the MAAC-ECAR-NPCC regions. This includes appraisal of the anticipated near-term and future performance of the bulk power transmission systems within the MEN regions from an overall interregional standpoint. The Study Committee undertakes studies and analyses utilizing interregional load flows, inertial responses, transient stability studies, and other appropriate program packages, which may be available to appraise the ability of the interregional network to withstand representative severe contingencies without causing widespread cascading outages.

The goal of these appraisals is to provide assurance that system developments and operating procedures within each Region are being properly coordinated so they do not adversely affect other Regions. Studies are based on the most up-to-date plans of the individual systems. Analysis of any change in protected system development or mode of operation that will significantly affect interregional system performance is also included in the appraisals.

Coordination at the Regional level takes place through a number of different processes. The most notable of these are the Area Transmission Reviews and Reviews of Resource Adequacy done on a yearly basis by each of the NPCC Areas and reviewed and approved by the Region's membership.

NPCC also keeps a Major Project List, which includes generation projects in the Region that are in excess of 100 MW (See Appendix E) and also major transmission projects that affect the Bulk Power System. NPCC has a Special Protection Systems List, which is a database of all the Special Protection Systems (SPS) within the NPCC Region.

In addition, NPCC Members have the option of initiating a project review for new interconnections that may involve multiple Areas or have an effect extending beyond the interconnecting Area.

B. MID-ATLANTIC COORDINATING COUNCIL ("MAAC")

Background

The Mid-Atlantic Area Council's (MAAC) region encompasses nearly 50,000 square miles and, through its members, provides electricity to more than 23 million people about nine percent of the nation's population. MAAC members, through the PJM Regional Transmission Organization, serve customers in all or in parts of Delaware, Maryland, New Jersey, Pennsylvania, Virginia, and the District of Columbia. MAAC members have access to approximately 60,000 MW of installed generating capacity nearly eight percent of the nation's total and operate over 8,000 miles of bulk power transmission facilities.

The MAAC's mission is to preserve reliability in a restructured and competitive electric industry. To that end, under the MAAC Agreement, PJM members with assets in the MAAC region are MAAC members and are obligated to comply with MAAC and NERC operating policies and planning standards. As parties to the PJM Operating Agreement and in accordance with the PJM Tariff, MAAC members coordinate their operations, planning, and integration of generation and transmission facilities. Operation of the Allegheny Power (AP) facilities has been integrated into the PJM control area and compliance with operating measures are reported through MAAC. However, AP is still obligated by the planning criteria of the ECAR region and compliance with those criteria will continue to be assessed by ECAR.

The Members Committee approved the MAAC Standards Development Process in 2003. The process is an open standards development process that is based on NERC and American National Standards Institute (ANSI) procedures. It offers all stakeholders the opportunity to participate in the revision of existing MAAC criteria and development of new MAAC standards.

The Administrative Board approved the MAAC Compliance Monitoring and Enforcement Plan in 2003. This plan will be used to monitor compliance with the standards developed in the Standards Development Process noted above. MAAC continues to encourage the use of market-based solutions to facilitate standards compliance. The plan uses a structured notification process that, if necessary, includes executives of the non-compliant company and regulatory agencies.

This year, MAAC completed its first three-year cycle of generator protection audits. Every generator owner or operator with units of 20 MW or greater was audited to determine whether they were following their protection maintenance programs. MAAC also began a new three-year cycle of transmission protection audits.

2004 MAAC Reliability Assessment

Under the PJM Operating Agreement, the Transmission Owners Agreement and the PJM Open Access Tariff, the PJM Interconnection, LLC is responsible for developing a Regional Transmission Expansion

Plan to accommodate a range of needs including requirements for firm Transmission Service and Generator Interconnection Requests. The PJM Operating Agreement, Schedule 6, specifies that the

Regional Transmission Plan shall conform to the applicable reliability principles, guides and standards of NERC and MAAC in accordance with the procedures detailed in the PJM Manuals.

The MAAC Reliability Assessment demonstrates the MAAC Region's compliance with the MAAC Reliability Principles and Standards. This assessment includes the projects scheduled for service prior to or during the 2005 summer period. Highlights of the individual Criteria tests and some specific criteria exceptions are summarized below.

- Section I, Adequacy: The new projects improve reserve levels. Projected reserves based on resources committed to serve MAAC load meet the 2005 reserve obligation of 16.0 % established by the PJM Reliability Assurance Agreement-Reliability Committee.

- Section II, Transmission and Adequacy Security: The MAAC system as planned for the 2005 summer period, with the addition of new generation projects and transmission reinforcements, meets the requirements of MAAC Reliability Principles and Standards - Section II with the caveats noted in the report.

- Section III, General Requirements: The generating units scheduled for service prior to or during the 2005 summer period will provide additional reactive capability to the system. This will result in improved voltage regulation during normal and post-contingency conditions. This Assessment demonstrates that in general, with the caveats noted in this report, sufficient reactive capability with adequate controls to maintain acceptable voltage profiles under expected conditions have been installed.

- Section IV, Stability Requirements: Specific fault simulations were performed in the vicinity of units. In general, most projects and existing units complied with MAAC stability requirements.

- Section V, Abnormal Disturbances: The ability of the MAAC system to withstand abnormal disturbances involving loss of large blocks of generation, loss of certain substations, occurrence of multi-phase faults with delayed clearing and the loss of all the transmission lines located on the same right of way was tested as part of the analysis. The loss of all generation at several EHV plants resulted in some local overloads but did not result in any cascading condition. Where the EHV bus was included as part of the contingency the local overloads were mildly aggravated without causing any additional system burden.
- Section VII, Network Transfer Capability: The generating units scheduled for service prior to or during the 2005 summer period will provide additional capability to the system and, improve the ability of the MAAC bulk power system to meet the requirements of Standard VII of the Criteria, Network Transfer Capability. Network Transfer Capabilities are being determined for years 2005

and 2008 as part of the CETO/CETL analysis.

The 2004 MAAC Reliability Assessment report presents the results of a comprehensive reliability assessment of the MAAC system as planned for the 2005 summer period. The assessment tests the compliance of the plans with the MAAC Criteria when all of the planned additions, modifications and removals of generation and transmission facilities are completed and fulfills, in aggregate, the requirement for MAAC Filings. MAAC Reliability Assessment for 2010 summer peak is not yet completed and after completion will be published as an addendum. A Capacity Emergency Transfer Objective and Capacity Emergency Transfer Limit (CETO/CETL) analysis is being performed to determine the load deliverability capabilities for all MAAC designated areas for 2005 and 2008. The CETO/CETL analysis will also be published as an addendum.

The MAAC System, as planned for the 2005 planning period, with the addition of new generation projects and associated transmission reinforcements, meets the requirements of the MAAC Criteria for all tested contingencies.

The *2004 MAAC Reliability Assessment Report* may be accessed on the MAAC web site at:
http://www.maac-rc.org/assess/download/2004-maac-reliability-assessment.pdf

C. SIMULATION OF THE AUGUST 14, 2003 BLACKOUT

In April 2004, the US-Canada Power System Outage Task Force released the final report on the August 14, 2003 Blackout. As of this writing, the NERC Major System Disturbance Task Force (MSDTF), a team composed of the NPCC SS38 Working Group, augmented by representatives from EACR, MISO, PJM and SERC, is still performing dynamic simulation to reconstruct the whole Blackout event. The dynamic simulation allows the team to verify its hypotheses as to why particular events occurred and the relationship between different events over time. It also allows many "what if" scenarios be analyzed to determine whether a change in system conditions might have produced a different outcome.

The MSDTF plans to simulate the Blackout event up to the point where major system islands were formed. Once this work is finished, the NPCC SS38 Working Group will continue the investigation and simulation of each individual NPCC island to better understand how and why each island either survived or collapsed. These ongoing studies have been providing critical information to the US-CANADA Power System Outage Task Force, FERC, NERC and NPCC

See the NPCC website for additional information regarding the current status of NPCC Blackout-related activities. www.npcc.org

See the "*MAAC Report On Implementation of NERC, MORT and DOE-CA Recommendations from the August 14th Power System Blackout*", Revised December 31, 2004. http://www.pjm.com/committees/reliability/downloads/20041110-blackout-recommendations.pdf

D. OTHER REGIONAL COORDINATION AGREEMENTS

In addition to the joint coordination activities of the Regional Councils noted above, there are a number of other coordination agreements between and among the Northeastern Control Area operators. These include the following:

- "Northeast Independent Market Operators System Operation, Planning and Market Development Agreement", among the IMO, ISO-NE and NYISO, effective date: June 11, 2002
- "Interregional Coordination and Issue Resolution Agreement", between NYISO and PJM, effective date: March 15, 2002
- "Interregional Coordination and Seams Resolution Agreement: between ISO-NE and NYISO, effective date: July 31, 2003; Revised February 2004
- "Interim Inter-coordination Agreement", between MISO and IMO, effective date: July 1, 2004
- "Joint Operating Agreement" between PJM and MISO, Filed on December 31, 2003, Accepted by FERC Order "Modifying and Conditionally Accepting Joint Operating Agreement" issued on March 18, 20004, Docket No. ER04-375-000.

There are also bi-lateral Interconnection Agreements between each of Northeastern Control Area operators, as follows:

- Interconnection Agreement between the IMO and NYISO, effective date: July 1, 2004
- Interconnection Agreement between the Ontario Hydro and Manitoba Hydro Electric Board, compilation of April 1981
- Interconnection Agreement between NYISO and PJM, effective date: May 1, 2000
- Interconnection Agreement between NYISO and ISO-NE, effective date: August 14, 2000
Interconnection Agreement Between Independent Electricity Market Operator And Hydro-Québec TransÉnergie, effective December 23rd 2004
- Interconnection Facilities Agreement Between Hydro One Networks Inc. And Hydro-Québec TransÉnergie, effective December 23rd 2004
- Interconnection Agreement Between New York Independent System Operator Inc. And Hydro-Québec TransÉnergie, effective October 21st 2002
- Interconnection Service Agreement between Niagara Mohawk Power Corporation and Cedars Rapids Transmission Company Limited, September 17th, 2004.
- Interconnection Agreement Between NEPOOL Participants And Hydro-Québec TransÉnergie, effective March 1983
- Interconnection Agreement Between New Brunswick Power and Hydro-Quebec TransÉnergie, effective 1979

V. INTER-AREA SYSTEM PLANNING ISSUES, RISKS, AND PLANS

The following issues were identified by the Northeastern ISOs and Control Areas as appropriate issues and risks for consideration in the first Northeastern Coordinated Plan, which is discussed in Section VI. This should be considered a "first-cut" and non-exclusive listing that is being provided for stakeholder review and input.

Resource Adequacy

Resource adequacy is an issue of common concern for the Northeast region, where there are similar requirements but differing implementation methodologies. Each of the U.S. ISO regions has a market-based procurement mechanism, while Ontario is currently studying such a requirement. In New Brunswick, each market participant acquires capacity through a bilateral market, but the New Brunswick System Operator has overall responsibility to ensure that adequate capacity is available for New Brunswick consumers. In Québec, the entity responsible for resource adequacy is Hydro-Québec Distribution (HQD). HQD must present for approval the "Development Plan" to the Régie de l'énergie, which proposes a resource plan to meet short- term and long-term load growth. The Régie Law necessitates that HQD proceeds through call for tenders for resources in addition to the Heritage electricity provided by HQ Generation. Issues for further analysis include sharing of reserves and capacity as a means to improve the overall reliability of the region. PJM participates in the NPCC Resource Adequacy and Tie Benefits Study (under the NPCC CP-10 working group.).

Fuel Diversity

In that the dominant source of new generations in the Northeast is based on natural gas, often without an alternate fuel capability, there is a potential risk for the region, especially during the winter period when interruptible gas supplies are used for heating purposes.

In 2003, 30% of New England's energy consumption was supplied from plants that can only be fired by natural gas, making fuel diversity a significant concern for this region. The plant capacity in New England that is capable of burning gas only, or burning either gas or oil, is 37% (Source: ISO-NE RTEP04). However, in many cases, there may be severe restrictions on the ability of these dual fuel plants to burn oil. To ameliorate New England's high dependency on natural-fired generation, steps have been taken to increase use of dual-fuel plants in New England that can effectively operate on oil under emergency conditions. In addition, operating and market-solution procedures have been implemented to improve reliability during periods of shortages in natural gas supplies.

The table below shows the fuel diversity of each of the NPCC regions and PJM based on the 2004 generating capacity of those regions. It shows while capacity fired by natural gas is dominant in New England and New York, coal is the predominant fuel in PJM, and hydro is predominant in Quebec

ISO/RTO	Type of Generating Capacity										
	Total	**Gas/Oil**		**Coal**		**Nuclear**		**Hydro**		**Other**	
	MW	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**	**%**	**MW**
New England 2004	30,958	63	19,622	9	2,786	14	4,383	10	3,205	3	962
New York 2004	37,549	60	22,708	10	3,597	14	5080	15	5,777	1	387
PJM 2004	143,878	35	50,978	42	59,760	19	27,426	4	5,301	-	413
Ontario 4/29/04	30,501	14	4,364	25	7,564	36	10,831	25	7,676	-	66
Hydro Quebec 2004	32,963	5	1,478	-		2	675	93	30,660	-	150
New Brunswick 2004	4430	45	1996	12	515	14	635	21	944	8	340
Total	280,279	36	101,146	27	74,222	17	48,989	19	53,563	1	2318

Notes:

- New England: Gas/Oil includes 8,081 MW of oil and 4,811 MW of dual fuel; Hydro includes 1,643 MW of pumped storage; "Other" includes 962 MW of miscellaneous generation (including wood, refuse, tires, etc.)
- Hydro-Quebec: "Other" includes wind generation
- New Brunswick: "Other" includes wood and orimulsion

The table suggests that greater interconnection capacity among the ISOs could increase the ability to share generating resources if any problems arise related to fuel shortages, delivery capability, or generic plant shutdowns.

Retirements

Retirement of resources is a potential risk to maintaining adequate resources for the region and will affect inter-regional power flows as well. Refer to the discussions under each Control Area's plans found in Section III above, and also see Appendix H for a listing of future retirements by region.

Nuclear Unit Issues

Nuclear re-licensing, refueling, and long-term maintenance outages must be accounted for in coordination of regional planning.

Environmental Regulations

Current and pending environmental regulations (e.g., greenhouse gas limitations on CO_2 emissions) can have a significant impact on resource availability and, thus, the reliability of the interconnected system.

Mercury in the environment is a growing concern, and EPA has proposed new mercury-reduction regulations for coal generating plants (Utility Mercury Reduction Rule). The EPA proposed two options for reducing mercury by up to 70%. These reductions would add another compliance cost for coal plants near the end of this decade.

The continuing costs for compliance within the inter-ISO region for SO_2 and NO_x allowance caps are increasing with the escalating values of allowances for both of those pollutants. Current values for SO_2 allowances are $700 per ton and $2,200 per ton for Vintage 2004 allowances.
CO_2 will likely become a compliance requirement for fossil plants affecting coal plants the most, because of their higher CO_2 emissions versus natural gas. The Regional Greenhouse Gas Initiative (RGGI) is a cooperative multi-stakeholder effort of nine northeastern states (ME, NH, VT, MA, RI CT, NY, NJ, and DE) to develop a model rule for a CO_2 cap and trade system in that nine-state region. The RGGI plan is that the cap will be implemented individually by the nine states over several years and culminate in a CO_2 cap on the entire nine-state region's CO_2 emitting plants, some time around 2008–2010. The RGGI design must take into account the Control Area Operators' need to maintain reliability under all combinations of operating conditions.

Coal plants would be the most severely affected with an additional CO_2 allowance (or credit) cost for compliance. A RGGI cap would apply only to plants in the eastern part of PJM giving them a higher operating cost than PJM plants outside the RGGI region. The added cost for CO_2 would likely affect the dispatch and corresponding transmission flows throughout the northeastern region. The effects of these pending regulations on existing generators could impact transmission flows within the broader northeastern region.

In Ontario, the Environmental Protection Act regulates the quantity of NO_x, SO_2 and mercury emissions that are permissible from fossil-fuel electricity plants. Both NO_x and SO_2 emissions have been capped, and reductions are mandated by 2007. For fossil-fuel plants, the NO_x cap will decrease by 53% in 2007 (from a 2000 voluntary cap of 38kt/yr), and the SO_2 cap will decrease by 25% (from an initial limit of 175 kt/yr). Ontario currently has an emissions trading program in place for NO_x and SO_2 (though not for CO_2), and the development of a Renewable Energy Credit (REC) market is being contemplated.

In New Brunswick, emissions are regulated pursuant to the *Clean Air Act* administered by the New Brunswick Department of Environment and Local Government. In 2001, NB Power Corporation submitted to the New Brunswick Department of Environment and Local Government its Sulfur Dioxide Emissions Reduction Program, which outlines specific actions to satisfy the SO_2 emission constraints. The refurbishment of the Coleson Cove Generating Station has enabled NB Power to meet emerging SO_2 emissions reduction targets, as well as significantly reducing NO_X emissions.

The New England Governors and Eastern Canadian Premiers are working to achieve regional and national reductions in nitrogen oxide (NO_x), sulphur dioxide (SO_2), and mercury emissions. These reductions in the coal-fired electric utility sector are as follows:

- 30% reduction in NO_x emissions by 2007
- 20-50% reduction in mercury emissions by January 2005 (base year 1995) and a 60-90% reduction by January 2010
- 30% reduction in SO_2 emissions by 2005 (86,100 tonnes limit) and 50% reduction by 2010 (61,500 tonnes limit)

Canada ratified the Kyoto Protocol in December 2002 and has committed to reducing greenhouse gas emissions to 6% below 1990 levels though 2008–2012. However, Canada has not yet introduced legislation that would implement the changes necessary to achieve the reduction targets.

Alternative Resources (Wind and Distributed generation)

Alternative resources, which often have intermittent or other unique characteristics, pose challenges for planning and operations of the interconnected system. New York State is currently in the final stages of assessing the reliability impacts of potentially large amounts of wind energy additions to its resource mix. Québec has developed its own set of requirements for integration of wind generation. These requirements were used to study a Call for Tenders of 1,000 MW of new wind generation in the Gaspésie peninsula, which will result in the addition of 990 MW between 2006 and 2012. Other wind projects are proposed or in construction.

FERC has held several technical conferences to discuss the implications of increased usage of wind power and has recently introduced a new rulemaking proposing to establish additional technical interconnection requirements for wind power and alternative resources.

Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) are state standards established for load-serving entities (LSE) requiring that a specific percent of their energy be supplied each year by renewable forms of energy. Starting in a specified year, this percentage increases each year to some maximum amount. The standards are defined differently by each state, as are the technologies that are considered to be acceptable renewable sources. The states in the region that have implemented RPS are ME, MA, RI, CT, NY, NJ, and PA. Maryland is also proposing an RPS. Non-competitive LSEs (e.g., municipal utilities) are usually exempt from compliance with RPS.

The impact of these standards will be to encourage the development of new renewable projects in the region, even in states without RPS requirements. This is because credit is usually given for out-of-state purchases, even from other ISO/RTO regions, and usually with deliverability requirements.

Generally, the states with RPS require that around 8% of the LSEs' energy comes from new clean renewables by 2013. In addition, some states have a percentage requirement for a second class or tier of a different set of renewables that may be larger in size than the first class or tier.

The government of Ontario has committed to increasing the capacity of renewables to 5% of total electric capacity by 2007 and to 10% (2700 MW) by 2010. Practically speaking, the technologies that appear most likely to be built for RPS are wind generators, biomass plants, photovoltaic solar, and fuel cells. Depending on their size, the wind and biomass plants will likely be interconnected to the distribution system, or, in the case of plants greater than about 20 to 25 MW, to the transmission system. Compliance with RPS can be done with the purchase if Renewable Energy Credits, which are MWH generated by a compliant renewable generator for a given period, or alternatively, a $/MWH payment made to the state at a stated value reflective of the REC price. To stimulate investment in renewable generation, the government awarded 400 MW following an RFP process, which is expected to be repeated in the future.

The provincial government in New Brunswick is currently working to establish Renewable Portfolio Standards.

Until sufficient renewable projects are proposed for each state, it is too early to see the composite impact that all the RPS renewables will have on the transmission system and its reliability

Demand-Side Resources

The integration of demand-side measures into the resource mix offers both planning and operating challenges for the region. The impact of these resources across regions and their eligibility for capacity and reserve credits are issues for consideration.

External Contingency Issues

As the August 14, 2003, blackout has demonstrated, reliability in the Northeast is vulnerable to external contingencies. The identification and analysis of such contingencies must be included in any future regional planning analyses. The seasonal inter-regional analyses conducted under the VACAR-ECAR-MAAC (VEM) and MAAC-ECAR-NPCC (MEN) Study Committees will serve as an important source of input for such analysis. (See Appendix D)

Blackout-Related Issues

There are numerous additional Blackout-related studies and requirements (both international, regional and local) that must be accommodated in future regional planning efforts.

VI. NORTHEASTERN COORDINATED SYSTEM PLAN: 2006

Overview

As noted above, one of the key elements of the Protocol is the development of a Northeastern Coordinated System Plan (NCSP) for the entire Northeast Region (defined by the Protocol as encompassing the NPCC region as well as PJM). Section 4.3 of the Protocol describes the process for the development of the NCSP, which is outlined below.

Each participant will continue to perform its individual planning analysis, as required by its tariffs and procedures and applicable reliability rules. The results of these area analyses will be included in, and form the basis for, the further studies to be performed under the NCSP. Such additional studies will focus on those proposed projects or system conditions that may have significant inter-regional implications. The goal of the NCSP is to achieve a reliable system of generation, distributed resources, demand-side management and transmission for the Northeast region. The NCSP will identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets. By so doing, it is intended that the NCSP will help ensure that sufficient regulated transmission solutions are identified in the event that market-based responses do not respond to identified needs.

All analyses performed to evaluate cross-border impacts on the system facilities of one of the parties will be based upon the criteria, guidelines, procedures, or standards applicable to those facilities. In the event that system upgrades may be needed to resolve cross-border impacts, such upgrades will be constructed according to the standards, terms, and conditions of the party on whose system the upgrade is to be constructed.

It is intended that each party include in its own system plan all elements of the NCSP that are to be constructed on its system. Each party will be responsible for securing approval of these elements, in addition to those required under its individual planning analysis, in accordance with their respective governance and approval procedures. If a party cannot secure approval of such elements of the NCSP, or is unable to implement the construction of these elements, the parties may agree to re-evaluate the plan to develop alternative recommendations, resolve disputes in accordance with the provisions of the Protocol, or pursue any other remedies that may be available through applicable federal or provincial regulatory agencies.

Issues for Consideration in NCSP 2006

Based on their knowledge and experience in planning for their respective areas, the participants have identified the following non-exclusive list of specific issues for inclusion in the next Northeastern Coordinated Plan. The parties intend to solicit stakeholder input and comment on these and other issues during the initial implementation phase for NSCP 2006.

- Joint queue interconnection projects with inter-area impacts
- Other transmission projects with inter-area impacts
- Fuel diversity: electric/gas infrastructure issues
- Resource adequacy: long range projections
- 1,000 MW wheel between NY and PJM
- Project Neptune (connecting PJM and NYISO regions)
- Large loss of source in New England

Proposed Process and Timeline

It is the intent of the parties and participants in preparing the Coordinated System Plan for 2005 that it will be used to form the basis for developing the first truly coordinated NCSP for the Northeast region. In accordance with the protocol, the next step to initiate this process is to seek input from regional stakeholders. To that end, the parties propose the following schedule:

March 2005	Issuance of Draft Northeastern Coordinated System Plan: 2005 for stakeholder review
June 2005	First IPSAC meeting to review Northeastern Consolidated System Plan: 2005 and to obtain input for preparation of the NCSP 2006
July 2005	Start of analysis
November 2005	IPSAC meeting to review preliminary study results
March 2006	Final Draft NCSP issued for stakeholder review
May 2006	IPSAC meeting to receive comments on final draft
Summer 2006	Issue NCSP 2006

APPENDICES

APPENDIX A

NORTHEASTERN ISO/RTO PLANNING COORDINATION PROTOCOL

NORTHEASTERN ISO/RTO

PLANNING COORDINATION PROTOCOL

Table of Contents

1. Introduction

This protocol describes the foundation for processes and procedures through which coordination of system planning activities will be implemented by the ISOs and RTOs of the northeastern United States and Canada. The parties to this protocol will be the PJM Interconnection, L.L.C. (PJM), the New York Independent System Operator (NYISO), and ISO New England (ISO-NE). This document shall be binding on each party's successors and assigns. The activities of the parties, as defined under this protocol, will be conducted in coordination with the Regional Reliability Councils of northeastern United States and eastern Canada (NPCC$! and MAAC). In addition, the protocol was developed with participation from Ontario's Independent Electricity Market Operator (IMO), Hydro-Quebec (TransEnergie) and New Brunswick Power. These entities are not parties to this protocol but have accepted to participate, at their convenience, in the Data and Information Exchange process and in regional planning studies for projects that may have inter-area impact to ensure better coordination in the development of the Interconnected Power System. This could include participation in studies of Interconnection Requests and studies of Long Term Firm Transmission Service Requests. The Canadian entities are not participating in any sharing o£ the costs, as proposed under this protocol, of future system upgrades or modification.

The protocol describes the committee structure that is established to coordinate inter-area planning activities, procedures for the exchange of planning-related data and information, and the system planning analysis procedures that will be utilized by the parties. The primary purpose of this protocol is to contribute, through coordinated planning, to the on-going reliability and the enhanced operational and economic performance of the systems of the parties. This will be accomplished in two ways. First, the parties will coordinate the evaluation, on an on-going basis, of Tariff-provided services, such as generation interconnection, to recognize the impacts that result across the seams between systems. Second, the parties will produce, on a periodic basis, a Northeastern Coordinated System Plan (NCSP) that integrates 1) the system plans of the parties, 2) on-going load growth and retirements or deactivations of infrastructure, 3) market-based additions to system infrastructure, such as generation or merchant transmission projects, 4) distributed resources, such as demand side and load response programs, and 5) transmission upgrades identified, jointly, by the parties to resolve seams issues or to enhance the coordinated performance of the systems.

The Parties agree that, to the extent that changes may be required in their respective tariffs to implement certain provisions of this protocol, they will use their best efforts to achieve the necessary approvals through their respective governance and regulatory processes. Until such tariff changes are enacted or in the event that one or more of the parties is unable to enact such tariff changes, the affected provisions of the protocol will not be implemented until it can be modified to ensure consistency with the tariffs of the parties.

2. Committee Structure

This section defines the committee structures established in support of the comprehensive process of coordinating system planning activities through the Northeastern ISO/RTO Planning Coordination Protocol.

The protocol establishes:

- an Inter-area Planning Stakeholder Advisory Committee, and
- a Joint ISO/RTO Planning Committee.

2.1. Inter-area Planning Stakeholder Advisory Committee

The parties shall form an Inter-area Planning Stakeholder Advisory Committee (IPSAC) for the purpose of allowing for review of and input to coordinated system planning activities by all stakeholder groups.

Initially, the representatives to the existing ISO/RTO planning advisory committees will comprise the membership of the IPSAC. With respect to this protocol, in all cases, stakeholders may include the market participants within the regions of the parties, governmental agencies, regional state committees, regional reliability councils, and any other parties with an interest in the coordination of planning related to the northeastern ISO/RTOs. All such stakeholders may join the IPSAC. With respect to the development of the NCSP, the IPSAC will meet:

- prior to the start of each cycle of the coordinated planning process to review and provide input on the assumptions and scope of analysis upon which the development of the NCSP will be based,
- at least once during the development of the NCSP to review and provide feedback on the preliminary results of the coordinated system planning analysis and to identify sensitivity analyses that may be required, and
- upon completion of the NCSP to review the final results of the system planning analysis.

2.2. Joint ISO/RTO Planning Committee

The parties shall form a Joint ISO/RTO Planning Committee (JIPC), comprised of representatives of the staff of the parties, for the purpose of coordinating planning activities, identifying issues related to the Inter-area planning process, and facilitating the resolution of such issues. In addition, ad hoc committees will be established to resolve specific planning coordination issues. Such ad hoc committees may include representatives of the JIPC, the affected transmission owners, and other interested stakeholders. The JIPC shall:

- be responsible for coordinating planning activities under this protocol, including the development of planning procedures, the conduct of planning analyses, and the production of the NCSP,
- be responsible for the maintenance of a web site and required e-mail lists for the communication of information related to the coordinated planning process,

- meet on at least a semi-annual basis to review and coordinate system planning activities,
- support the review by any federal or provincial agency of elements of the NCSP,
- support the review by multi-state entities, regional state committees, state, provincial, or other similarly situated entities, including the facilitation of new transmission facility additions, and
- establish working groups as necessary to provide adequate development and review of the inter-area plan. Where practical, the JIPC will utilize existing working group and committee structures in support of inter-area planning activities.

Chairmanship of the JIPC will be rotated among the parties with the term of the chairmanship to be one year. The chairman will be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings.

Additionally, the JIPC will establish a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation, and other activities.

Each party shall be responsible for its own costs to support the activities of the JIPC. Administrative costs included for public meetings, website maintenance, etc. shall be divided among the parties on a load ratio basis.

3. Data and Information Exchange

This section defines the on-going process by which data and information are shared among the parties in support of the more comprehensive process of coordinating system planning activities through the Northeastern .ISQ/RTO Planning Coordination Protocol. Identified are:

- the data and information that will be exchanged among the parties,
- the schedule for the exchange of data and information,
- the formats to be used for the exchange of data and information
- the procedures for the development of required analysis models,
- the rules and procedures to be followed with respect to the confidentiality of data and information exchanged among the parties, and
- the procedures for the identification of contact persons, responsible for the exchange of data and information under this protocol.

3.1. Data and Information Exchange

Each party shall provide the others with information as maybe required for the performance of planning studies as agreed upon by the JIPC. The parties will also exchange such data and information as is needed for each party to plan its own system accurately and reliably and to assess the impact of conditions existing on the systems of the other parties. Confidentiality of data and information will be governed by a confidentiality agreement among the parties. All release and/or exchange of data and information will be done in a manner consistent with FERC Critical Energy Infrastructure Information guidelines and procedures, and any confidentiality or information release policy or agreements to which each Party may be subject.

Each party shall provide the others, on a periodic basis, with all data required for system planning analyses that may include the development of power flow cases, short-circuit cases, and stability cases, including ten-year load forecasts and any retirements or deactivations of transmission or generation facilities. All critical assumptions that are used in the development of these cases shall be included, as well as system planning documents that may include long-term and short-term system assessments, geographical system maps, one-line and breaker diagrams, and contingency lists for use in power flow and stability analyses, including lists of all single contingency events and appropriate multiple facility common-mode contingencies consistent with the applicable criteria of the area.

Each party shall identify all interconnection requests that are expected to impact the operation of other parties' systems. The parties will work together to develop the necessary tools or decision criteria so that such potential impacts can readily be identified.

Each party shall provide the others with information regarding long-term firm transmission service and other transmission services on all interfaces relevant to the coordination of planning among their systems.

In addition to the on-going exchange of planning-related information and coordination of planning process activities, System Operations, Market Operations, and System Planning personnel representing the parties will meet once each year to review the issues impacting the coordination of these functions as they impact long range planning and the coordination of planning among their systems.

3.2. Schedule of Data and Information Exchange

Most of the data and information exchanged under this protocol will be provided on an annual basis. Reports of planning or operational analyses will be provided as they are completed. The dates for the exchange of necessary data that may include load forecasts and power flow, short circuit, and stability modeling data will be established by the JIPC to correspond to the appropriate point in the annual planning process time line of each party.

To facilitate the coordination of planning analyses, the parties will inform each other, on a monthly basis, of any interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of the other parties' systems. On a quarterly basis, the parties will inform each other of the current status of all interconnection requests that have been so identified.

3.3. Data and Information Formats

To the extent practical the maintenance and exchange of power system modeling data will be implemented through databases. The formats for information exchanges will be agreed upon by the parties. Where possible, other information that may include geographical system maps and one-line diagrams will be provided in an electronic format agreed upon by the parties

3.4. Coordination of Power System Analysis Model Development

Detailed procedures for the development of power system analysis models will be prepared and documented by the JIPC. The parties shall develop common power system analysis models to perform the analyses required to develop the NCSP. Models will be developed for necessary system planning analyses such as power flow analyses, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the parties, the parties will perform a detailed review of the appropriateness of the required power system models. Other analyses, as agreed upon by the JIPC, will be fully coordinated and may include areas such as resource adequacy and related studies as well as congestion studies. Changes to baseline data and updates to the power system analysis models will be performed annually to capture all system upgrades and allow analyses to accurately identify cross border impacts. Coordination of power system analysis models will rely upon existing working groups to the maximum extent practical.

3.5. Data Contacts

Each party shall name a person responsible for the coordination and exchange of all data and information, on a periodic basis, as agreed to by the parties pursuant to this protocol.

4. Northeastern Coordinated System Plan (NCSP)

This section defines the ongoing process by which system planning analyses are performed by the parties and a coordinated system plan is developed through the Northeastern ISO/RTO Planning Coordination Protocol. The primary purpose *of* this process is to ensure that coordinated analyses are performed *to* identify power system reliability concerns or other system needs, and *to* recommend upgrades *to* mitigate identified reliability concerns. The identification *of* other system needs should, in turn, provide market signals to address those needs, including investment in generation, merchant transmission facilities, and demand *(or* load) response programs, which promote power system reliability and robustness. If the market responds with an adequate solution *to* identified system needs or a solution that helps *to* mitigate identified reliability concerns, these solutions will be evaluated and included in the NCSP. If inadequate market solutions are proposed, regulated solutions will be developed and included in the NCSP. As a result, the NCSP will present a coordinated, cost effective transmission plan that identifies appropriate projects for ensuring reliability of service and a robust system. This coordinated plan is updated as market responses *to* identified problems develop.

The goal of the NCSP is to achieve a reliable system of generation, distributed resources, demand side management and transmission, and helps to ensure that sufficient regulated transmission solutions are identified in the event market-based resources do not respond to identified needs. Therefore, the NCSP identifies expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets in full coordination with market responses.. Discussed are:

- the procedures for on-going analysis of interconnection requests that may impact the systems of the parties,
- the procedures for ongoing analysis of requests for long-term firm transmission service and other transmission services that may impact the systems of the parties,
- the procedures for periodic analysis of the collective system of the parties and the development of a NCSP, and ~
- the procedures for the establishment of contact persons, responsible for the coordination of system planning analysis activities under this protocol.

As will be discussed later in this section, all analyses performed to evaluate cross-border impacts on the system facilities of one of the parties will be based on the criteria, guidelines, procedures or standards applicable to those facilities. In the event that system upgrades are required to resolve cross-border impacts, such upgrades will be constructed according to the standards, terms, and conditions of the party on whose system the upgrade is required.

4.1. Analysis of Interconnection Requests (also applicable to Merchant Transmission)

In accordance with applicable Interconnection Procedures under which the parties are providing Interconnection Service, each party will coordinate with the other parties the conduct of any studies required for determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies will include the following steps:

- Upon the posting to the OASIS of a request for interconnection, the entity receiving the request ("direct connect system") will notify potentially impacted systems of the request, along with the information provided in the posting.
- If the potentially impacted system believes that its system may be materially impacted by the interconnection, the potentially impacted system will contact the direct connect system and indicate a desire to participate in the interconnection studies that may be performed. The JIPC will develop screening procedures to assist in the identification of interconnection requests that may impact systems or parties other than the direct connect system.
- If the direct connect system performs or contracts for the performance of any system impact studies for the interconnection customer, the direct connect system will contact potentially impacted systems to determine the nature and cost of any studies to be performed to test the impacts of the interconnection on the potentially impacted system who will perform the studies. The parties will strive to maximize the efficiency of the coordinated study process.
- Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable interconnection procedures of the direct connect system. Both the direct connect system and the potentially impacted systems will use their best efforts to meet the applicable study timelines. However, the direct connect system will be responsible for satisfying the requirements of its tariff related to the interconnection request. The potentially impacted system may participate in the coordinated study either by taking responsibility for performance of studies of its system, or by providing input to the studies to be performed by the direct connect system. The study cost estimates indicated in the study agreement between the direct connect system and the interconnection customer will reflect the costs and the associated roles of the study participants. The direct connect system will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.
- The direct connect system will collect from the interconnection customer and forward to the potentially impacted systems the costs incurred by the potentially impacted systems associated with the performance of such studies.
- If in the determination of the potentially impacted system, the results of a coordinated study indicate that network upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such network upgrades in the system impact study prepared for the interconnection customer.
- Requirements for the construction of such network upgrades will be under the terms and conditions of the potentially impacted system and consistent with applicable federal or provincial regulatory policy.

Each party will maintain a separate interconnection queue. A composite listing of interconnection requests will be maintained by the JIPC of all interconnection projects that have been identified as potentially impacting the systems of parties other than the direct connect system. In all cases, the queue date associated with an interconnection request for which coordinated studies will be performed will be determined by the original request to the direct connect system. The composite listing of interconnection requests will be maintained on the web site established by the JIPC for the communication of information related to the coordinated planning process. The web site will contain links to the web sites of each of the parties where individual interconnection study results will be maintained.

4.2. Analysis of Long Term Firm Transmission Service Requests

In accordance with applicable procedures under which the parties may be providing Long- Term Firm Transmission Service, each party will coordinate with the other parties the conduct of any studies required in determining the impact of applicable requests for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following steps:

- The parties will work together to coordinate the calculation of ATC values associated with long term firm point-to-point transmission services, based on contingencies on the systems of each party that may be impacted by the granting of such services.
- Upon the posting to the OASIS of a request for long-term firm transmission service, the system receiving the request will notify potentially impacted systems of the request, along with the information provided in the posting.
- If an Impact Study is to be performed, and if the potentially impacted system believes that its system may be materially impacted by the service or request for Merchant expansion, the potentially impacted system will contact the entity receiving the request and indicate a desire to participate in the studies that may be performed. The JIPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.
- If the system receiving the request performs or contracts for the performance of any system impact studies for the transmission service customer, the system receiving the request will contact potentially impacted systems to determine the nature and cost of any studies to be performed to test the impacts of the service on the potentially impacted system and who will perform the studies. The parties will strive to maximize the efficiency of the coordinated study process.
- Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable transmission service procedures of the system receiving the request. Both the system receiving the request and the potentially impacted systems will use their best efforts to meet the applicable study timelines, However, the system receiving the request will be responsible for satisfying the requirements of its tariff related to the request.
- The potentially impacted system may participate in the coordinated study either by taking responsibility for performance of studies of their system, or by providing input to the studies to be performed by the system receiving the request. The study cost estimates indicated in the study agreement between the system receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The system

receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

- The system receiving the request will collect from the interconnection customer and forward to the potentially impacted systems the costs incurred by the potentially impacted systems associated with the performance of such studies.
- If in the determination of the potentially impacted system, the results of a coordinated study indicate that network upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the system receiving the request will identify the need for such network upgrades in the system impact study prepared for the transmission service customer.
- Requirements for the construction of such network upgrades will be under the terms and conditions of the potentially impacted system and consistent with applicable federal or provincial regulatory policy.

4.3. Development of the Northeastern Coordinated System Plan

Each party shall engage in such system planning activities as are necessary to fulfill its obligations under its agreements and open access transmission tariff. Such planning shall conform to applicable reliability requirements of the North American Electric Reliability

Council, applicable regional reliability councils, or any successor organizations, the local sub-.
region and areas, and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each party agrees to document the procedures, methodologies, and business rules that are utilized in preparing and completing this system planning report.

In addition, each party will coordinate with the other parties the conduct of any studies required to assure the reliable, efficient, and effective operation of the power system and assist in the preparation of an NCSP. Each party's applicable periodic system plan will be incorporated into the NCSP. The NCSPwil1 also include a section that describes the results of the analysis for the combined systems, as well as the procedures, methodologies, and business rules that were utilized in preparing and completing the joint system analysis.

Coordination of studies required for the development of the NCSP will include the following steps:

- Periodically, the parties agree to perform a comprehensive, coordinated inter-area system assessment and system expansion planning study. Sensitivity analyses will be performed, as required, based on a review by the IPSAC and the JIPC of discrete reliability problems or operability issues that arise due to changing system conditions.
- Each party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will rotate among the parties.
- The JIPC will develop a scope and procedure for the inter-area planning assessment,
- The scope of the study will include evaluations of the powers system against the applicable reliability criteria, operational performance criteria, and economic performance criteria.

- Each party will provide a baseline model that includes all system enhancements included in the party's system expansion plan, and all of the committed interconnection projects and any associated system upgrades.
- The study will initially evaluate the reliability of the combined power systems. Any upgrades required to resolve criteria violations will be agreed upon and included in an updated baseline model.
- The performance of the combined power systems will be tested against agreed upon operational and economic criteria, where applicable, using the updated baseline model. Upgrades required to resolve operational and/or economic performance criteria violations will be included in the NCSP.
- Where applicable, and consistent with planning and operating criteria, the parties will evaluate operational solutions as a means to resolve reliability, operational, and/or economic performance criteria violations. Operational solutions will be considered for either short term or long-term application and, when determined to be an appropriate means to resolve such violations, will be identified in the NCSP.

The NCSP will be reviewed with the IPSAC Feedback from this Committee will be included in the final NCSP.

Each party will include in its own system plan all elements of the NCSP, which are to be constructed on its system. Each party will be responsible for securing approval of the elements of the NCSP, which are to be constructed on its system through the procedures by which the party secures approval of its system plan.

In the event that a party does not secure approval of elements of the NCSP which are to be constructed on its system or does not proceed, or is unable to implement the construction of such elements, the remaining parties may agree to re-evaluate the plan in an effort to develop alternative recommendations, pursue dispute resolution through procedures established by the parties, or pursue any other remedies that may be available through applicable federal or provincial regulatory agencies.

4.4. Cost Allocation

The allocation of cost for elements of the NCSP will be addressed consistent with applicable provisions of each Party's tariff, and any applicable guidance provided by FERC Orders or interpretations.

4.5. Contact Persons

Each party shall name a representative and an alternate to the JIPC and a person with primary responsibility for all coordinated system planning analyses performed under this protocol. The representative to the JIPC will be responsible for assuring that the proper policies and procedures are maintained and followed.

5. Dispute Resolution

If the parties to this Protocol are unable to complete any of the tasks outlined herein, or if an issue arises associated with implementation of this Protocol that cannot be resolved by the JIPC, any party may refer the matter to the Chief Executive Officers of the parties ("CEOs"). The CEOs agree to schedule a meeting to resolve the issue or to provide direction, as appropriate, on a priority basis.

In the event that the CEOs do not reach agreement on any issue referred to them within ten (10) days, then any party may refer the matter to a neutral, third-party Dispute Resolution Service, which may include the FERC's Dispute Resolution Service, and request a session be convened to initiate non-binding dispute resolution services. Costs assessed by the Dispute Resolution Service for the use of such service shall be borne by all parties to this agreement equally.

PJM, NYISO or ISO NE may refer issues between or among them that are not resolved pursuant to the above provisions to FERC's Dispute Resolution Service and request a session be convened to initiate non-binding dispute resolution services.

6. Liability and Indemnity

The parties acknowledge that, in the course of our cooperative efforts under the protocol, each RTO and ISO that is a party to the protocol will continue to maintain and be obligated by its own, separate and individual governance, tariffs and agreements.

More specifically, each party additionally agrees as follows:

- Nothing in the protocol is intended to override the separateness or compromise the independence of each party.
- Each party agrees to indemnify, defend and hold the other party harmless from and against any and/or all judgments, awards, demands, liability, losses, costs and expenses (including reasonable attorneys' fees and court costs) arising out of any claim by a third- party grounded in facts or events taking place within its RTO or ISO and arising from the protocol. Except for the preceding obligation to indemnify, no party to this Protocol shall have any liability to any other party to this Protocol for any obligation arising hereunder.
- Each party agrees that the protocol does not create or acknowledge any partnership, joint venture or further agreement or obligation among the parties above and beyond the exact words of the protocol. Nor does the protocol create any third-party beneficiaries or impart any legal right or expectation to any member or market participant of a party.
- Each party acknowledges and agrees that the protocol will not impact the rights *of* each party's respective members under the separate and individual governance, tariffs and agreements of each RTO or ISO.

EXECUTION

Wherefore, this Agreement is executed by the parties as of ______________________ which is the effective date of the Agreement.

PJM Interconnection, LLC

By: Phillip G. Harris 11/19/04

Phillip G. Harris — Date
President and CEO

New York Independent System Operator

By: W.J. Museler 11/22/04

William J. Museler — Date
President and CEO

ISO New England Inc.

By: Gordon van Welie 12/08/04

Gordon van Welie — Date
President and CEO

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APPENDIX B

LINKS TO EACH AREA'S

TRANSMISSION PLANS

LINKS TO AREA TRANSMISSION PLANS

REGION	LINK
IESO	http://www.hydroonenetworks.com/en/
ISO-NE	http://www.iso-ne.com/committees/planning_advisory_committee/RTEP04/RTEP04_Exec_and_Summary_Report_Final_Publication.pdf
NEW BRUNSWICK	http://www.nbso.ca (website under development)
NYISO	http://www.nyiso.com/services/planning.html
PJM	http://www.pjm.com/planning/rtep-baseline-reports/baseline-report.html
HYDRO-QUEBEC TRANSENERGIE	http://www.transenergie.com/oasis/hqt/en/entree.htmlx
NPCC	http://www.npcc.org/documents.asp

APPENDIX C

NPCC PLANNING ACTIVITIES

NPCC PLANNING ACTIVITIES

Task Force on Coordination of Planning (TFCP)

The NPCC Task Force on Coordination of Planning reviews the adequacy of the NPCC systems to supply load, considering forecast demand, installed and planned supply and demand resources, and required reserve margins in accordance with Guidelines for Area Review of Resource Adequacy (Document B-8) and based on a schedule set forth in the Reliability Assessment Program.

NPCC TFCP coordinates the review of the compliance of future Control Area plans with the *Basic Criteria* including an analysis of resource and transmission system additions, and the potential inter-area effects of special protection systems, based on a schedule set forth in the Reliability Assessment Program. Specific projects, which in the opinion of the TFCP could have an impact on the reliability of the NPCC bulk power system, may be reviewed outside of the set schedule.

NPCC coordinates the review of proposed new or modified special protection systems in accordance with the Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (Document C-16).

NPCC TFCP initiates inter-area and inter-regional studies where improved reliability may be achievable through joint planning. Control Area assessments and resource reviews, as well as transmission interim and comprehensive reviews, are evaluated and must be approved by TFCP.

NPCC CP-8

Resource and transmission adequacy is improved by considering interconnections with neighboring systems in reliability evaluations. NPCC Control Areas are currently able to meet the NPCC resource reliability criterion with lower installed reserves than would be required without interconnections. As planned reserves of the NPCC areas change in the future, the dependence on interconnections for emergency assistance to provide adequate reliability will vary. The objectives of CP-8 are:

- Annually assess the short-term resource adequacy of NPCC, its constituent Control Areas, and neighboring regions to meet demand. This is done probabilistically using the G.E. MARS program. CP-8 is also responsible for the maintenance of the G.E. MARS database to ensure that it remains current.

- Evaluate whether the interconnection benefits assumed by each Control Area are reasonable by demonstrating compliance with the NPCC resource reliability criterion.

- Evaluate whether a Control Area's proposed resources meets the NPCC resource reliability criterion, assuming the Control Area's load forecast uncertainty. This is done through a review of the technical aspects of each area's Comprehensive Review of Resource Adequacy prior to its submission to the NPCC Task Force on Coordination of Planning (TFCP).

- Identify any potential reliability impacts that may result from a Control Area's proposed resources, fuel supply, and/or environmental restrictions.

- Examine the impact of evolving market rules on the overall NPCC resource reliability criterion.

- Participate in and provide technical assistance to TFCP with regard to NPCC and Control Area compliance with NERC planning standards as related to resource adequacy.

- Conduct other studies regarding Control Area reliability and NERC compliance as required by TFCP.

CP-8 activities include the following:

- The report, *Northeast Power Coordinating Council Multi-Area Probabilistic Reliability Assessment for Summer 2004* (issued in May of 2004).

- A study assessing NPCC Interconnection Tie Benefits (approved July 2004).

- Other reports evaluating resource adequacy of Ontario, the Maritimes, Quebec, New England and New York were reviewed and approved under the NPCC peer review process

NPCC CO-12

The NPCC Task Force on Coordination of Operation (TFCO) established the Operations Planning Working Group (CO-12) to conduct overall assessments of the reliability of the generation and transmission system in the NPCC Region on a seasonal basis. These assessments discuss topics such as historical operational experiences and their applicability for the period to be studied; the extent to which emergency operating procedures may be implemented within NPCC areas; sensitivities that may impact resource adequacy, including temperature variations, new generating plant delays, load-response measures, environmental restrictions, solar magnetic activity and system voltage, and generator reactive-capability limits; and communication protocols within NPCC. The assessments are coordinated with the NPCC CP-8 and document a deterministic analysis of NPCC's resource and capacity situation.

The latest report, *Northeast Power Coordinating Council Reliability Assessment for Summer 2004*, was issued with the CP-8 study in May of 2004

SS-38 Working Group

The overall objective of the SS-38 Working Group is to analyze dynamic phenomena that may affect interconnected system reliability, especially in the area of low frequency oscillations. The SS-38 Working Group also promotes ongoing improvement of inter-regional data collection procedures and dynamic analysis capabilities.

The study, *NPCC 2002 Adequacy of Under-Frequency Load Shedding*, reviewed the criteria and guidelines for protection against off-nominal frequency operation. Simulations were performed to determine: a) if the present NPCC under-frequency load-shedding program satisfies requirements of the NERC compliance program; and, b) if the present under-frequency settings are adequate to meet NPCC criteria. Analysis of electrical islands included intra-area, inter-area and inter-regional boundaries. The results of the study and supplemental analyses are still under discussion at NPCC and will also be coordinated with the neighboring regions.

SS-37 Working Group

The SS-37 Base Case Development Working Group is responsible for developing a library of solved load-flow cases and associated dynamic data for use by the member companies and regional / inter-regional study groups in planning and evaluating future systems and current operating conditions. This data are also used in meeting the modeling requirements of the NPCC and NERC compliance programs. SS-37 also coordinates mid-year modeling updates and transfer assumptions for use in studies, both regional and inter-regional analyses. For example, transmission adequacy assessments are now being conducted with common base case assumptions.

In accordance with NPCC criteria, SS-37 has also been charged with performing the NPCC Overall Transmission Assessment. This assessment will include an evaluation of thermal, dynamic, and voltage performance of the 2009 system. The dynamic performance of the 2009 system will be assessed by simulating a representative set of contingencies and transfer conditions. The contingencies and transfer conditions studied will be limited to those brought forward by SS38 members for this purpose. Most pertinent, SS38 members will make this determination through an open process by soliciting the judgments of persons in their Control Areas/Regions who are involved in dynamic and system impact studies on an ongoing basis. These people are to be selected on the basis of their potential for inter-area and inter-regional impact for the developing system, including loss of source contingencies in New England. Scheduled for completion by December 2004, the Overall Transmission Assessment will supplement and serve as a further verification of the Control Areas' Interim and Comprehensive Transmission Reviews.

APPENDIX D

INTER-REGIONAL PLANNING ACTIVITIES

NPCC CP-10 Collaborative Planning Initiative Objective

The objective of the CP-10 Phase II Study was to identify and prioritize, based on potential adverse impacts on reliability, potential transmission bottlenecks in the Northeast Interconnected Transmission System (NPCC and MACC).

The CP-10 Phase II Study prioritizes northeastern region (NE, NY, IESO, PJM) bottlenecks (i.e., transmission constraints) based on potential adverse impacts on reliability. The GE MAPS/MWFLOW program was used for this assessment. Production cost data was acquired from a publicly available generic database. The analysis includes the effects of expected (modeled as those with 18.4 approvals and having begun construction) and more aggressive generation additions (modeled as having 18.4 approval), as well as variations in production-cost data modeled as specific fuel-price changes that could be representative of fuel interruptions.

Analysis of specific transmission reinforcements to relieve transmission congestion was beyond the scope of the CP-10 study. However, inter-area coordination employed in the CP-10 studies has provided meaningful insight in identifying potential inter-area reliability impacts resulting from projected changes in system facilities and the impact of variable fuel costs.

The results show that relief of major interfaces that are internally constraining in New England, including East-West, SEMA-RI, and the Norwalk Harbor to Northport 1385 tie, would also improve possible inter-area transfers and thus improve overall reliability. The study also showed limitations in the Blissville-to-Whitehall New York tie could limit transfers with New York.

MEN/VEM INTER-REGIONAL ASSESSMENT REPORT SUMMARIES

The following are highlights from the 2004/05 Winter VACAR-ECAR-MAAC (VEM) and MAAC-ECAR-NPCC (MEN) reports. These assessments continue to examine wide-area transfers. They also have continued the process of modeling transfers that do not completely mirror NERC reliability regions but try to do so as nearly as possible while representing realistic transfer dispatches that accommodate market existing markets and market changes. The makeup of the systems and markets in the MEN/VEM vicinity has been going through major changes, and the types of transfer simulations conducted in the MEN and VEM Assessments have been changing accordingly. On May 1, 2004, Commonwealth Edison was fully integrated into the PJM energy market. On October 1, 2004, AEP and Dayton P&L were also incorporated into the PJM market. Duquesne Light was incorporated on January 1, 2005. Dominion Virginia Power is expected to join PJM later in 2005. As such, the boundaries of PJM are moving significantly beyond those of the MAAC region.

Both Inter-regional Transmission System Reliability Assessments reflect the integration of ComEd into the PJM energy market operation through the inclusion of a 500 MW firm transfer in the MEN/VEM base case to account for the transmission reservation from the ComEd system to the eastern portion of the PJM system. This is meant to represent the system effect of the ComEd/PJM market-integration pathway. The baseline condition in the assessments did not include the integration of AEP and Dayton Power & Light into the PJM Market in order to provide a direct comparison of results to the 2003/04 Winter Assessment. Sensitivity tests were conducted examining the resulting changes in transfer capabilities due to the AEP and Dayton Power & Light change.

Major changes in modeling from the 2003/04 Winter Base Case to the 2004/05 Winter Base Case include:

Additions:

- Approximately 3,100 MW of new generation within ECAR
- Approximately 2,950 MW of new generation within PJM
- Approximately 4,950 MW of new generation within NPCC
- Approximately 3,200 MW of generation has been added in VACAR

Net Interchanges:

- ECAR to PJM is 13 MW lower
- ECAR to NPCC is unchanged
- ECAR to VACAR is 150 MW higher
- VACAR to PJM is unchanged
- PJM to NPCC is 269 MW higher

A high-level summary of the results contained in each report are:

MEN:

Comparison of the limits reported in the assessment with those reported in previous assessments must be tempered with the realization that the study results reflect different operations due to different market alliances. However; qualitative comparisons are discussed in this assessment where appropriate and highlighted below.

The MEN 2004/05 Winter Study has identified thermal limits to inter-regional transfers in several portions of the system. NPCC to ECAR and ECAR to NPCC transfers are limited by facilities in the vicinity of the Ontario-Michigan Interface. Some limiting facilities include:

- St. Clair 345/220-kV Transformer
- Lambton-St. Clair L4D 220 kV

NPCC to PJM transfers have a first limit in western Pennsylvania. Limiting facilities for this transfer include:

- Homer City 345/230-kV Transformer
- Goudey-Oakdale 115 kV

PJM-to-NPCC transfers are limited by the North Meshoppen and E. Towanda-Hillside 230-kV facilities in northeastern Pennsylvania.

For the baseline condition the transfer limit level changes were small to moderate as follows:

Transfer Path	FCTTC Change from Winter 2003/04
ECAR to NPCC	400 MW higher
PJM to NPCC	200 MW lower
NPCC to ECAR	200 MW higher
NPCC to PJM	150 MW lower

This is the result of few transmission system changes since 2003/04 Winter in locations that significantly affect inter-regional transfer flow patterns. The changes are generally attributed to differences in import and export participation.

As indicated in the Introduction, the baseline condition in the assessments did not include the integration of AEP and Dayton Power & Light into the PJM Market in order to provide a direct comparison of results to the 2003/04 Winter Assessment. Sensitivity tests were conducted to analyze transfers to and from Non-PJM ECAR (ECAR without AP, AEP, and Dayton P&L) and PJM-New (Classic PJM, which includes AP, plus AEP, and Dayton P&L), and transfers to and from NPCC. Although not directly comparable, these results generally show moderate to significant (some only 200–400-MW change or so) increases in FCTTCs due, in part, to resources within AEP and Dayton P&L participating in the PJM market, causing both import and exports to be dispersed throughout a wider electrical area.

The MEN transfer limits are sensitive to the setting of the inter-regional phase angle regulators (PARs). The NPCC –MAAC PARs are modeled in a manner consistent with the last several MEN Assessments. The 2004/05 Winter MEN Assessment reflects the current status of the NPCC-ECAR PARs.

2004/05 Winter Michigan-Ontario Interface PAR status:

- Scott–Bunce Creek circuit B3N and PAR – PAR and line have both failed and are out of service. Return-to-service dates for both the circuit and PAR are uncertain.
- Lambton–St. Clair L4D circuit PAR not in service but is expected to return to service during the 2004/05 winter period. In the study baseline condition, the PAR is non-regulating, bypassed.
- Lambton–St. Clair L51D PAR returned to service in September 2004. In the study

baseline condition, the PAR is non-regulating, bypassed.

- Keith–Waterman J5D PAR is in service and regulating

Due to the uncertainty surrounding in-service dates and adoption of accepted operating agreements for the Michigan-Ontario Interface PARs (in circuits J5D, L4D, and L51D) to control interface power flows, additional sensitivity analysis was performed. These additional study results identify the same 1st, 2nd and 3rd contingency and limiting facilities, but the order of severity changes. In general, with the phase shifters regulating at the prescribed set-point, transfer capability increases from east to west by as much as 400 MW and decreases west to east by up to 300 MW. These studies did not attempt to optimize the impact of these controls on transfer capability.

VEM RELIABILITY ASSESSMENT
May 2004

1. INTRODUCTION

This report documents results of the **V**ACAR, **E**CAR, and **M**AAC 2004 Summer Inter-regional Transmission System Reliability Assessment, which was conducted to assess the anticipated performance of the VEM bulk transmission system during the 2004 summer peak load period. It is one of a continuing series of studies made under the Inter-Area Reliability Coordination Agreement among the VEM areas to provide a periodic analysis of the effects on system performance of changes in generation, transmission, and in area loads, as well as other developments in system conditions.

This study, as did the 2003 summer study, analyzes transfers to and from PJM (including AP) and ECAR (excluding AP). Previous studies looked at transfers to and from the traditionally defined MAAC and ECAR regions.

In addition, this report contains results of power flow testing of system contingencies under bulk power transfer conditions, including NON-SIMULTANEOUS transfer capabilities, the identification of key facilities, voltage limitation curves, outage and transfer response factors, and power flow diagrams. It also includes some analysis of the potential effects of SIMULTANEOUS transactions on VEM transfer capabilities.

2. RESULTS

A. GENERAL

The VEM bulk transmission system is often heavily utilized. Emergency transfer capability may be limited during peak periods. Transfers may be curtailed at times utilizing the NERC Transmission Loading Relief (TLR) Procedure. More information about the TLR procedure may be obtained from NERC Operating Policy Number 9, which may be obtained from the NERC home page at www.nerc.com.

Evolution of the interconnected network continues. Allegheny Power is now fully integrated as part of PJM's market operations. Voltage limits for flowgates along the ECAR, MAAC and VACAR interfaces are determined using methods developed by PJM. When transmission limits are reached, if necessary after PJM redispatch, transfers are curtailed by implementing the NERC TLR Procedure while monitoring the new voltage limits.

This study analyzes transfers to and from PJM including PJM West (AP) and ECAR excluding PJM West. Non-Simultaneous First Contingency Incremental Transfer Capabilities (FCITCs) and First Contingency Total Transfer Capabilities (FCTTCs) are used as indicators of the relative strength of the interconnected system.

Based on the analyses documented in this study, during this summer:

- Transfer limits changed as follows:

Transfer	FCTTC Change from 2003 Summer
▪ ECAR to VACAR	1250 MW Lower
▪ PJM to VACAR	450 MW Higher
▪ VACAR to ECAR	*No limit found
▪ PJM to ECAR	*No limit found
▪ VACAR to PJM	1600 MW Lower
▪ ECAR to PJM	2150 MW Lower
▪ ECAR to VP	1100 MW Lower
▪ PJM to VP	750 MW Lower
▪ ECAR to Duke/CP&L	1350 MW Lower

* No limit found at same transfer level in 2003 Summer

- Voltage limitations may occur for the following transfers:

    - ECAR to VACAR
    - ECAR to VP
    - ECAR to PJM
    - ECAR to Duke/CP&L
    - VACAR to PJM
    - PJM to VP

- Several facilities were found to have thermal limits for regional and subregional transfers.

- Double Contingencies

All recent VEM studies have identified several combinations of overlapping transmission outages which would result in severe voltage depressions, thermal overloading, or large angular differences for base transfer conditions. Such performance indicates the likely need for major immediate system adjustments following the first contingency, or for emergency actions if the overlapping outages occur suddenly. To reduce the probability of multiple outages, maintenance outages of VEM transmission facilities must be coordinated.

B. COMPARISON OF 2004 SUMMER WITH 2003 SUMMER RESULTS

The differences between the 2004 Summer and the 2003 Summer FCTTCs and FCITCs are discussed below. It should be noted that there were no changes in study procedures for this study. The analyses followed the same study procedures that have been in use for the past several studies.

A comparison of the import limits, including the primary factors contributing to any increases or decreases are listed below.

VACAR IMPORT LIMITS

ECAR to VACAR

The **total** transfer capability has **decreased** by 1250 MW from last summer to a FCTTC of 2750 MW. The decrease is due to higher base loadings, primarily due to the additional 837 MW base transfer modeled from PJM West (AP) into traditional PJM, the 500 MW transfer modeled from Commonwealth Edison into PJM, and the free flow modeled on the IMO-Michigan PARs.

PJM to VACAR

The **total** transfer capability has **increased** by 450 MW from last winter to a FCTTC of 4000 MW. Base flow has reversed on the Dickerson-Pleasant View circuit this summer due to the addition of a 500-230 kV transformer at Pleasant View and the difference in PJM modeled generation dispatch.

ECAR IMPORT LIMITS

VACAR to ECAR

The **total** transfer capability is unchanged from last summer. The FCTTC of 4450+ MW is the result of no limit found at the incremental 5000 MW test level.

PJM to ECAR

The **total** transfer capability is unchanged from last summer. The FCTTC of 4700+ MW is the result of no limit found at the incremental 5000 MW test level.

PJM IMPORT LIMITS

VACAR to PJM

The **total** transfer capability **decreased** by 1600 MW from last year to a FCTTC of 2800 MW. The decrease is due to changes in the PJM generation dispatch.

ECAR to PJM

The **total** transfer capability has **decreased** by 2150 MW from last year to a FCTTC of 1400 MW. The decrease is due to changes in the PJM generation dispatch.

SUBREGIONAL IMPORT LIMITS

ECAR to VP

The **total** transfer capability has **decreased** by 1100 MW from last year to a FCTTC of 900 MW.

PJM to VP

The **total** transfer capability has **decreased** by 750 MW from last year to a FCTTC of 1400 MW. The decrease is due to higher base loadings, the 500 MW transfer modeled from Commonwealth Edison into PJM, and the free flow modeled on the IMO-Michigan PARs. Also, base flow has reversed on the Dickerson-Pleasant View circuit this summer due to the addition of a 500-230 kV transformer at Pleasant View and the difference in PJM modeled generation dispatch.

ECAR to Duke/CP&L

The **total** transfer capability has **decreased** by 1350 MW from last year to a FCTTC of 2500 MW. The difference is due to 456 MW of Dynegy generation in the vicinity of Antioch not being dispatched this summer.

3. BACKGROUND INFORMATION

The VACAR-ECAR-MAAC (VEM) study area covers 12 states stretching from Indiana and Kentucky, east to New Jersey, and south to South Carolina. Despite the wide geographic expanse, the area is closely coupled electrically by extensive EHV transmission facilities. During other than peak conditions, the transmission network, which integrates the VEM area, has a west-to-east bias in power flows.

Recently, interchange of power at peak load has become extremely sensitive to electricity prices. The result of this price sensitivity is that small differentials of price can cause large interchange of power in the more historical west-to-east direction or also in an east-to-west direction. Heavy north-to-south and south-to-north interchanges have also occurred.

In light of the considerable exchange of power between the VEM regions, interfaces have been identified which are monitored to control the flows to reliable levels. Critical flow conditions may cause limits for transfers within the VEM area.

Three of these interfaces, the PJM western, central, and eastern interfaces, may limit PJM imports. These interfaces consist of 500 kV lines that carry a large portion of the transfers. As a result, very heavy loading can occur on the lines, with or without contingencies, and 500 kV station voltages may become unacceptably low.

Phase Angle Regulators (PARs) on all major ties between northeastern PJM and southeastern New York help control unscheduled power flows through PJM, resulting from non-PJM power transfers. In all of the simulations conducted for this study, a 1000 MW wheeling schedule was maintained through Public Service (PS). The Ramapo PARs are controlling a 240 MW flow on the 500 kV circuit from Branchburg to Ramapo, as related to the interchange between PJM and NPCC. Due to the recent failure of B3N, the PARs on the IMO/MECS interface are not modeled in service this summer.

Facilities in eastern AP are highly responsive to west-to-east transfers. As a result, these facilities may reach their reliable loading limits. Under those conditions, west-to-east transfers will need to be either frozen or curtailed to safe levels. The TLR, a step-by-step procedure developed by the NERC Operating Reliability Subcommittee (ORS) for preventing transmission overloads and curtailing transmission transactions, will be implemented to avoid or relieve any overload which cannot be relieved by PJM redispatch. The TLR identifies the actual transactions, by priority and use, which cause Operating Security Limit violations. The TLR considers the actual paths over which transactions are flowing, not their contract paths, to determine which transactions to curtail and or freeze. More information about the TLR may be obtained from the NERC home page at www.nerc.com.

Operating experience indicates the central or eastern interfaces in AEP's Roanoke Transmission Region may limit VACAR imports and ECAR exports. Outage of facilities within either interface may overload the remaining facilities and significantly increase loading of parallel non-AEP EHV facilities. Similarly, outages of parallel EHV facilities, including those in eastern ECAR, SERC, and PJM, can increase loading on these AEP internal interfaces. Variable series capacitor compensation, up to 60% of the line reactance in steps of 10%, can be inserted in the Kanawha-Matt Funk 345 kV circuit. The appropriate level of compensation will be used to optimize performance of the interfaces.

VACAR generation facilities are dispersed throughout VACAR and are connected to an integrated 500 kV and 230 kV transmission system. The availability of generation on both the 500 kV and the lower voltage network can create moderate-to-heavy loading on the VACAR 500-230 kV transformers. Because the transformers are moderately responsive to transfers, contingency overloads may occur for imports into VACAR.

4. REGIONAL AND SUBREGIONAL APPRAISALS

VACAR Appraisal

Base Conditions

This summer's study again modeled transfers to and from ECAR and PJM with Allegheny as part of PJM West. The base case modeled only firm, capacity backed transfers.

Loading on the 500 kV facilities along the AP/PJM/VP interface are considerably higher this summer than last. This higher base loading is primarily due to the modeling of an additional 837 MW from PJM West (AP) into traditional PJM this summer, the modeling of a 500 MW "pathway" from Commonwealth Edison into PJM, and the modeling of the PARs on the Ontario-Michigan interface as free flowing this summer.

Import and Export Capabilities

NON-SIMULTANEOUS transfers to and from ECAR and to and from PJM were simulated during peak load conditions. Single contingency outages during modeled operating conditions were examined to assess the ability of the VEM interconnected network to support regional and subregional transfers into VACAR.

ECAR to VACAR transfers are voltage limited this summer at the 2200 MW incremental transfer level. The first thermal FCITC occurs at the 2250 MW level. The decreases from last summer in both the voltage and thermal FCITC levels (-1250 MW and -1650 MW respectively) is due to the increased base flows along the PJM West (AP)/PJM/VP interface described above.

The FCITC for ECAR to VP transfers occurs at the 900 MW level. The voltage limit occurs at the 1000 MW incremental transfer level. The decreases from last summer in both the voltage and thermal FCITC levels (-1000 MW and -1850 MW respectively) is due to the increased base flows along the PJM West (AP)/PJM/VP interface described above.

The thermal FCITC for ECAR to Duke/CP&L transfers occurs at the 1950 MW level, a decrease from last year's 3300 MW level. The voltage limit occurs at the 2150 MW incremental transfer level, a decrease from last year when no voltage limit occurred at the 4000 MW incremental test level. The decrease in the voltage FCITC level is due to the increased base flows along the PJM West (AP)/PJM/VP interface described above.

It should be noted that, if either VP or PJM were importing from ECAR or PJM West (AP) at a higher base transfer level than that modeled in this study, FCITCs for ECAR transfers to PJM, VACAR, VP, and Duke/CP&L, could be lower.

The FCITC for PJM to VACAR transfers occurs at the 4650 MW level for a circuit loading limit. Last summer the limit occurred at the 3900 MW transfer level. The previous limit did not appear due to the Pleasant View 500-230 kV transformer addition and the difference in the PJM generation dispatch.

The FCITC for PJM to VP transfers occurs at the 2050 MW level for a circuit loading limit. Last summer the limit occurred at the 2800 MW transfer level. The limiting and outaged facilities changed due to the Pleasant View 500-230 kV transformer addition and the difference in the PJM generation dispatch this summer.

No limit was found at the 5000 MW test level for VACAR_to ECAR transfers this summer or last.

The FCITC for VACAR_to PJM occurs at the 2150 MW level for a circuit loading limit. Last summer the transfer was limited at the 4050 MW level by a voltage limit on the PJM Central Interface. The decrease is due to PJM dispatch changes.

Simultaneous Transfers

In this summer's study, PTI's MUST program was used to test the effects of simultaneous non-VEM parallel transfers on the VEM transfer limits. ECAR to VACAR transfers were run with simultaneous transfers from MAIN to MAAC and from MAIN to FRCC. Similarly, VACAR to ECAR transfers were run with simultaneous transfers from MAAC to MAIN and from FRCC to MAIN.

The ECAR to VACAR FCITC is 2250 MW with no MAIN to FRCC transfer. When the MAIN to FRCC transfer reaches 3100 MW, ECAR to VACAR transfer capability is reduced to 1200 MW. When the MAIN to FRCC transfer reaches 4000 MW, ECAR to VACAR transfer capability is reduced to 800 MW. When the MAIN to FRCC transfer reaches 5000 MW, ECAR to VACAR transfer capability is reduced to 100 MW.

The ECAR to VACAR FCITC is 2250 MW with no MAIN to PJM transfer. When the MAIN to PJM transfer reaches 1150 MW, ECAR to VACAR transfer capability is reduced to 0 MW.

The VACAR to ECAR FCITC exceeds the 5000 MW test level with no FRCC to MAIN transfer. When the FRCC to MAIN transfer reaches 1000 MW, VACAR to ECAR transfer capability is limited to 5000 MW. When the FRCC to MAIN transfer reaches 2700 MW, VACAR to ECAR transfer capability is reduced to 4050 MW. When the FRCC to MAIN transfer reaches 5000 MW, the VACAR to ECAR transfer capability is reduced to 1500 MW.

The VACAR to ECAR FCITC exceeds the 5000 MW test level with no PJM to MAIN transfer. When the PJM to MAIN transfer reaches 3900 MW, the VACAR to ECAR transfer capability is limited to 5000MW. When the PJM to MAIN transfer reaches 5000 MW, VACAR to ECAR transfer capability is reduced to 4800 MW.

ECAR Appraisal

General Observations

The transfers that are modeled in the 2004 summer base case are scheduled firm capacity backed transactions. Conditions modeled include a net base interchange of 285 MW from ECAR to PJM and 572 MW from ECAR to VACAR companies.

Base Loading Conditions

Critical 500 kV corridors on the AP-PJM-VP interfaces are heavily loaded in this case and are higher than last year. Several factors contributed to the change in flows in the VACAR-ECAR-MAAC interfaces. Among the most significant are:

- An additional 837 MW is modeled from AP to PJM this summer
- A 500 MW transfer is modeled from Commonwealth Edison to PJM this summer
- Three of four PARs on the IMO-MECS interface are modeled out of service this summer
- Bunce Creek-Scott 230 kV is out of service this summer
- An increase in load in the ECAR region

Import Capabilities

The ability of the VEM interconnected network to support transfers into the ECAR region was assessed by simulating NON-SIMULTANEOUS transfers from VACAR and from MAAC during peak load conditions and examining single contingencies during modeled operating conditions. The imports model a decrease in generation output dispersed over a large area to test overall system response.

The FCITC for ECAR imports from PJM are over the 5000 MW test level. Last summer the FCITC was 4200 MW due to a circuit loading limit. This change is due to changes in the PJM generation dispatch. The FCITC for ECAR imports from VACAR is again above the test level, unchanged from last summer.

Export Capabilities

In determining generation changes to be modeled for ECAR exports, consideration is given to projected reserve margins, individual company dispatch order, and proximity to the VACAR-ECAR-PJM interfaces.

The ECAR export FCITC and FCTTC test results have changed quite dramatically from last summer. Results from the base case test shows that the ECAR to VACAR FCITC is voltage limited at 2200 MW, 1250 MW lower than 2003 summer.

The ECAR to PJM FCITC is loading limited to 1100 MW, 2150 MW lower than 2003 summer. The ECAR to DUKE/CP&L FCITC sub-regional transfer is loading limited to 1950 MW. The ECAR to VP FCITC sub-regional transfer is voltage limited at 900 MW.

Double Contingencies

The transfers modeled in the base case tend to increase the overall flow of power on the transmission lines that make-up the VEM interface. Much of this power flows across a few facilities. As a result, there are outages that can cause a significant increase in the loading and subsequent transfer responses of other facilities. Double contingencies can overload facilities not indicated as FCITC limitations and at lower transfer levels. Similarly, simultaneous parallel transfers may cause overloads at levels below the indicated NON-SIMULTANEOUS FCITC's.

Various double contingency scenarios have been regularly examined in past studies. The most critical outages identified in those analyses are still expected to be of concern, due to overloads on underlying facilities, significant voltage drops, and large angular separations across the opened lines.

Other Loading Conditions

Facilities in AP and southeastern AEP respond to many factors. The critical voltages in AP during periods of heavy transfers will be affected by a variety of generation shifts or transfers within or between systems in the SERC, ECAR, MAAC, or NPCC regions. In addition to changing conditions within SERC, ECAR, MAAC, and NPCC, transfers between MAIN and MAAC, MAIN and SERC or SPP and SERC affect flows on critical AP and AEP facilities. As a result of the sensitivity of the AP and southeastern AEP transmission facilities to those external factors, conditions in AP and southeastern AEP may limit VEM transfers to levels below the published FCITC's.

MAAC Appraisal

The ability of the VEM interconnected network to support regional transfers into and out of MAAC was assessed for the 2004 Summer load period. In 2002 Allegheny Power was fully integrated into PJM's energy market operations as PJM West. In addition, a portion of Orange and Rockland Utilities Inc. load, located in New Jersey, was also incorporated into PJM's pool operations. In May 2004, Commonwealth Edison also joined the PJM market. As such, the boundaries of PJM have moved significantly beyond those of the MAAC region. The anticipated summer peak load of the PJM RTO is approximately 64,750 MW.

Comparison of the limits reported in this assessment with those reported in previous assessments must be tempered with the realization that this summer's assessment reflects the evolving market alliances and integrated operations that do not mirror NERC reliability regions. As a result of integrated operations certain limits that were previously external to MAAC have been internalized in the PJM LMP market and certain operating procedures have been modified accordingly. Limits reported for transfer capabilities involving PJM are not directly comparable with the MAAC limits reported in last summer's assessment. Qualitative comparisons are discussed in this assessment where appropriate.

Base Case Conditions

This summer, the modeled net tie line flow into PJM is 1558 MW. These interchanges reflect generation internal to PJM that is serving external RTO load as well as external generation serving internal PJM load. These transactions are supported by commensurate long term firm transmission service reservation on the PJM OASIS. In addition, a 500 MW pathway was modeled from Commonwealth Edison to PJM to simulate the ComEd integration into the PJM market on May 1, 2004.

Since last summer, approximately 4200 MW of new generating capacity has been added in PJM. As is typical for the MAAC region, discrete generation was forced out to model typical unit maintenance and Effective Forced Outage Rates (EFOR).

Coordinated operation with NYISO allows for adjustment of the Ramapo PAR schedule, as well as the PS-Con Ed Wheel PARs, to alleviate PJM system limits. For the winter period, absent additional NPCC-MAAC transfers, the Ramapo PARs were set to control the flow on the Branchburg-Ramapo 500 kV line to 242 MW.

Import and Export Capabilities

The facilities limiting transfers into and out of PJM remain consistent with those reported in last year's assessment. The variations in flow on these interfaces are expected and reflect the changing system conditions.

ECAR to PJM transfers this summer will be limited at a FCTTC level of approximately 1400 MW by a circuit loading limit.

As last summer, no limit was found at the incremental test level for a PJM to ECAR transfer.

VACAR to PJM transfers will be limited at a FCTTC level of 2800 MW by a circuit loading limit.

The PJM to VACAR total transfer capability is approximately 4000 MW.

Simultaneous Transfers

This year, the effects on VEM transfer limits of simultaneous transfers occurring between MAIN, FRCC, and the VEM region was tested.

APPENDIX E

NPCC MAJOR PROJECT LIST
(Updated: March 29, 2005)

NPCC Major Project List – March 29, 2005

	AREA	PROJECT NAME	Status [1]	In-Service Date	Part of BPS [2]	Included in Last Area Review [3]	Included in NPCC Base Cases [4]
1.	NB-NE	Pt. Lepreau – Orrington, ME 345kV Line	S	2006	Y	Yes	Yes
2.	PJM-NY	Atlantic Energy Project Neptune – 600/750 MW monopole DC from PJM to Newbridge Rd. LI	S	2007	Y	Yes	Yes
3.	ON-ECAR	Phase shifting transformer on interconnection L4D, B3N and L51D	C	2005	Yes	Yes	Yes
4.	*ON-PJM or ECAR*	Hydro One/TransEnergie US DC Tie-Line Ontario to PJM or ECAR (990 MW)	S	2007-Q2	Yes	No	No
5.	***ON-QC***	Hawthorne TS – Québec border double-circuit 230 kV line	S	Under Review	No	Yes	Yes
6.	NB	Newcastle 345-230 kV terminal	S	2006	U	Yes	Yes
7.	NB	Memramcook 345/138 kV terminal	I/S	2004	Y	Yes	Yes
8.	NB	Edmundston 345/138 kV 2nd Parallel Transformer	S	2005	Y	No	No
9.	NE	West Rutland 345/115 kV 180 MVA Autotransformer #2	I/S	2003	Y	Yes	Yes
10.	NE	West Rutland – New Haven 345 kV line	S	2006	U	No	Yes
11.	NE	New Haven 345/115 kV Autotransformer #1	S	2006	U	No	Yes
12.	NE	New Haven 345/115 kV Autotransformer #2	S	2006	U	No	Yes
13.	NE	New Haven – Vergennes – Queen City 115 kV line	S	2006	U	No	Yes
14.	NE	Granite 230 kV 400 MVA Phase Angle Regulator	S	2006	U	No	Yes
15.	NE	Blissville 115 kV 100 MVA Phase Angle Regulator	S	2006	U	No	Yes
16.	NE	Granite 115 kV STATCOM, +/- 150 MVAr	S	2006	U	No	Yes
17.	NE	Granite 230/115 kV, 336 MVA Autotransformer #1	S	2006	U	No	Yes
18.	NE	Granite 230/115 kV, 336 MVA Autotransformer #2	S	2006	U	No	Yes
19.	NE	Sandbar 115 kV 350 MVA Phase Angle Regulator	I/S	2004	U	No	Yes
20.	NE	Plumtree-Norwalk 345 kV line	S	2006	U	No	No
21.	NE	Norwalk 345/115 kV 600 MVA Autotransformer #1	S	2006	U	No	No
22.	NE	Haddam 345/115 kV 600 MVA Autotransformer #1	S	2005	U	No	Yes
23.	NE	Wachusetts 345/115 kV Autotransformers #1 & 2	S	2006	Y	No	Yes
24.	NE	PDC Devon (Milford Power), CT (540 MW CC)	I/S	2004	U	Yes	Yes
25.	NE	Meriden Power, CT (544 MW CC)	C	2004	U	No	No
26.	NE	Kleene Energy Project, Middletown, CT (540 MW)	S	2005	U	No	No
27.	NE	Vermont Yankee Upgrade, Vernon, VT (125 MW)	S	2004	U	No	No
28.	NE	Glenbrook-Norwalk 115 kV Cables	P	2008	Y	No	No
29.	NE	M164 Line – 115 kV line from Huse Rd. to Bedford	C	2005	Y	No	No
30.	NE	V191 Line - 115 kV line from Bedford to North Merrimack	C	2005	Y	No	No
31.	NE	G128 Line - 115 kV line from Madbury to Rochester	I/S	2004	Y	No	No

	AREA	PROJECT NAME	**Status** [1]	**In-Service Date**	**Part of BPS** [2]	**Included in Last Area Review** [3]	**Include d in NPCC Base Cases** [4]
32.	NE/NY ?	Replace Norwalk Harbor-Northport cable	S	2006	?	N/A	N/A
33.	NE	Extend 115kV L-190 line to West Kingston	S	2006	N	No?	No?
34.	NE	Killingly 345/115 kV 600 MVA autotransformer	S	2006	U?	No?	No?
35.	NE	345kV cable Stoughton – K St w/ 345/115 kV transformer @ K St	S	2006	U?	No?	No?
36.	NE	345kV cable Stoughton – Hyde Park St w/ 345/115 kV transformer @ Hyde Park	S	2006	U?	No?	No?
37.	NE	345kV cable Stoughton – K St w/ 345/115 kV transformer @ K St	S	2007	U?	No?	No?
38.	NY	Niagara Upgrade (325 MW hydro) (10 units completed, remaining 3 units phased in at the rate of approximately one per year from 2005-2007)	C	2006	U	Yes	Yes
39.	NY	Bethlehem Energy (Albany Steam, 400 → 730 MW repowering)	C	2005	U	Yes	Yes
40.	NY	Poletti, Astoria (500MW)	C	2006	U	Yes	Yes
41.	NY	KeySpan, Spagnoli Road, LI (250 MW CC)	S	2008-09	U	Yes	Yes(O/S)
42.	NY	Calpine Wawayanda Energy Center, Middletown (500MW)	S	2008	U	Yes	Yes
43.	NY	Reliant Astoria Repowering – Phase 1 (367 MW)	S	2010	U	Yes	Yes
44.	NY	East River Repowering (288MW)	C	2005	U	Yes	Yes
45.	NY	Mirant, Bowline Pt. 3, W. Haverstraw (750 MW)	S	2008	U	Yes	Yes
46.	NY	SCS Energy, Astoria (1000 MW CC)	C	2006-07	U	Yes	Yes
47.	NY	ANP Brookhaven Energy, LI (580 MW)	S	2006	U	Yes	Yes(O/S)
48.	NY	Glenville, Rotterdam (540MW)	S	2007	U	Yes	Yes
49.	NY	PP&L Kings Park, Pilgrim, LI (300 MW)	W	N/A	U	Yes	Yes(O/S)
50.	NY	Besicorp, Reynolds Road (660 MW)	S	2007	U	Yes	Yes
51.	NY	Reliant Astoria Repowering – Phase 2 (173 MW)	S	2011	U	Yes	Yes
52.	NY	PSEG Power Radial Line to NYC (550 MW)	S	2008	U	Yes	Yes
53.	NY	TransGas Energy, New York City (1100 MW)	S	2008-09	U	Yes	Yes
54.	NY	PG&E/ Liberty Generation Connection to New York City (400-600 MW)	S	2007	U	Yes	Yes(O/S)
55.	NY	RG&E 4th Station 80 345/115 kV Transformer and Other Upgrades	S	2008	U	Yes	Yes
56.	NY	Flat Rock Wind Generation Project (240-300 MW)	S	2005-06	U	Yes	Yes
57.	NY	Mott Haven 345 kV Substation	S	2007	Y	Yes	Yes
58.	*ON*	TransAlta Project – Sarnia (580 MVA)	I/S	2003	yes	Yes	Yes
59.	*ON*	ENRON Project – Sarnia (274 MVA)	W	2004	yes	Yes	Yes
60.	*ON*	ENRON Project – Sarnia (336 MVA)	W	2004	yes	Yes	Yes
61.	*ON*	AES Project – Leamington (625 MVA)	W	06/05	U	Yes	Yes

	AREA	PROJECT NAME	Status [1]	In-Service Date	Part of BPS [2]	Included in Last Area Review [3]	Include d in NPCC Base Cases [4]
62.	*ON*	ATCO (Brighton Beach)Project – Windsor (680 MVA)	I/S	06/04	No	Yes	Yes
63.	*ON*	Sithe Canadian Holdings Inc. – Mississauga (913 MVA)	S	2007-Q1	Yes	Yes	Yes
64.	*ON*	Sithe Canadian Holdings Inc. – Brampton (913 MVA)	S	2006-Q4	Yes	Yes	Yes
65.	*ON*	AGSTAR Project – Tilbury (100 MVA)	S	/2005	No	Yes	Yes
66.	*ON*	AGSTAR Project – Tilbury (600 MVA)	P	12/06	No	Yes	Yes
67.	*ON*	Calpine Project - Sarnia (1000 MVA)	W	/2005	Yes	Yes	Yes
68.	*ON*	Ontario Power Generation Inc. – Portlands Energy Centre (formerly “Hearn”) (550 MW)	S	/2006-Q3	No	Yes	Yes
69.	*ON*	Imperial Oil – Sarnia (112 MVA) Phase I	I/S	2004	Yes	Yes	Yes
70.	*ON*	Northland Power – Thorold (273 MW)	S	2006-Q3	No	Yes	Yes
71.	ON	Pickering A (G4 515 MVA unit return to service)	I/S	2003	Yes	Yes	Yes
72.	ON	Pickering A (G1 515 MVA unit return to service)	S	09/05	Yes	Yes	Yes
73.	ON	Pickering A (G2 515 MVA unit return to service)	S	uncertai n	Yes	Yes	Yes
74.	ON	Pickering A (G3 515 MVA unit return to service)	S	Uncerta in	Yes	Yes	Yes
75.	ON	Bruce A (One 825 MVA unit G4 to return to service)	I/S	2003	Yes	Yes	Yes
76.	ON	Bruce A (One 825 MVA unit G3 to return to service)	I/S	02/04	Yes	Yes	Yes
77.	ON	Beck GS2 (192 MW Generation Rehabilitation)	C	2004	Yes	No	No
78.	ON	Superior Wind Energy – Bruce Peninsula (100 MW) Phase 1	S	09/05	No	No	No
79.	ON	Superior Wind Energy – Bruce Peninsula (100 MW) Phase 2	S	09/06	No	No	No
80.	ON	3rd Transmission Supply to Toronto – 3rd supply option.	S	06/10	U	No	No
81.	ON	Hearn SS – new 115 kV, 125 MVAr capacitor bank (SC12)	I/S	07/03	No	No	Yes
82.	ON	Leaside TS new 115 kV, 125 MVAr capacitor bank (SC13)	I/S	08/04	Yes	No	Yes
83.	ON	Wawa TS – (4x40 MVAr) new reactive compensation	I/S	12/03	No	No	Yes
84.	ON	Burlington TS new 115 kV, 125 MVAr capacitor bank (SC11)	I/S	06/04	No	No	Yes
85.	ON	Caledonia – new 230/115kV auto transformers (N6M/N2M) (200 MW)	I/S	06/04	No	No	Yes
86.	ON	Cherrywood TS – reterminate 500/230 kV autotransformers	I/S	06/04	Yes	No	Yes
87.	ON	Hawthorne TS – new 230/115 kV autotransformer and two 115 kV circuits	I/S	06/04	No	No	Yes

	AREA	PROJECT NAME	Status [1]	In-Service Date	Part of BPS [2]	Included in Last Area Review [3]	Include d in NPCC Base Cases [4]
88.	ON	Markham MTS#3 Expanded C11R/C12R) – new supply point	I/S	06/04	NO	No	Yes
89.	ON	Kent TS – new 230/115 kV (125MVA) autotransformer	S	2011	No	No	Yes
90.	ON	Detweiler TS – Replace T3 230/115 kV, 215 MVA autotransformer with 250 MVA unit	I/S	06/04	No	No	Yes
91.	ON	GLP transmission reinforcement (stages 2-4) – new 230 kV circuit from Anjigami to Mackay connected to 115 kV and upgraded 115 kV circuit No.3 Sault in-service	S	03/05	No	No	No
92.	ON	GLP transmission reinforcement (Final stage) – new 230 kV circuits Anjigami x Mackay and Mackay x Third line in-service	S	12/05	No	No	No
93.	ON	GLP transmission reinforcement – 230 kV circuit P21G thermal upgrade	S	2006	No	No	No
94.	ON	Northern Cross Energy – Goderich (50 MW)	S	2005-Q3	No	No	No
95.	ON	Northland Power Inc. – Kirkland Lake (48 MW)	I/s	2004-Q3	No	No	Yes
96.	ON	Hydro One for Vision Quest – Kincardine (15 MW)	S	2004-Q4	No	No	No
97.	ON	Hydro One for Vision Quest – Picton (22 MW)	S	2004-Q4	No	No	No
98.	ON	Superior Wind Energy Inc. – Manitoulin Island (100 MW)	S	2005-Q1	No	No	No
99.	ON	Superior Wind Energy Inc. – Leamington (200 MW)	S	2005-Q3	U	No	No
100	ON	Repower Wind Corp. – Manitoulin Island (54 MW)	S	2005-Q4	No	No	No
101	ON	Kalar TS: New 115/14.2 kV Transformer Station Off Lines A36N and A37N	I/S	11/04	No	Yes	Yes
102	ON	Trafalgar TS: New 230 kV, 300 MVAR Shunt Capacitor	C	05/05-	Yes	No	No
103	ON	Burlington TS: Install 230 kV, 300 MVAR Shunt Capacitor	I/S	12/04-	Yes	Yes	Yes
104	ON	Richview TS, John TS: Install, respectively, 230 kV, 412 MVAR and 115 kV, 100 MVAR Shunt Capacitor Banks	I/S	12/04-	Yes	Yes	Yes
105	ON	Cardiff TS: New Transformer Station (formerly Mississauga TS)	C	05/05	Yes	No	Yes
106	ON	Parkway TS: Build new Transformer Station with one 750 MVA, 500/230 kV Autotransformer	C	04/05	Yes	No	Yes
107	ON	Gartshore TS: Reconfiguration of Gartshore TS		2006	No	No	No
108	ON	Sudbury: New supply point to Falconbridge Nickel Rim Mine via 115 kV Circuit S6F	I/s	12/04	No	No	No
109	ON	Upgrade 115 kV Circuit H9A	P	12/07	No	No	No
110	ON	Leaside TS: Install second 125 MVAR Shunt Capacitor	C	05/05	U	No	No
111	ON	Niagara Reinforcement (75 km double circuit 230 kV line from Allanburg TS to Middleport TS	S	2007-Q3	Yes	No	No
112	ON	Essa TS – new 230 kV, 245 mVAR cap bank	S	05/06	Yes	No	No
113	ON	Cooksville TS – new 230 kV switching station	C	05/06	U	No	No
114	ON	AES Kingston Inc. – Bath (550 MW)	P	2007-	N	N	N

	AREA	PROJECT NAME	Status [1]	In-Service Date	Part of BPS [2]	Included in Last Area Review [3]	Included in NPCC Base Cases [4]
				Q4			
115	ON	AIM POWERGEN – Lake Erie Northshore (Phase 1 – 100 MW)	S	2005-Q4	N	N	N
116	ON	Algoma Steel Inc. – Sault St. Marie (172 MW)	P	2007-Q4	N	N	N
117	ON	Boralex Inc. – Mississauga (125 MW)	S	2006-Q1	U	N	N
118	ON	Brascan Power Inc. – Sault St. Marie (122 MW)	P	2007-Q4	N	N	N
119	ON	Bruce Power Inc. – Bruce A (G1& G2 1870 MW)	S	2007/04	Y	N	Y
120	ON	Calpine Canada Power Ltd. – Lambton (1195 MW)	P	2007-Q4	Y	N	N
121	ON	Calpine Canada Power Ltd. – Nanticoke (1195 MW)	P	2007-Q4	Y	N	N
122	ON	Calpine Canada Power Ltd. – Vaughan (960 MW)	P	2007-Q4	Y	N	N
123	ON	Canadian Hydro Developers – Melancthon Grey Wind Farm (Phase 2 - 165 MW)	P	2006-Q4	Y	N	Y
124	ON	Canadian Renewable Energy Corporation – Wolfe Island Wind Farm (360 MW)	P	2007-Q4	N	N	N
125	ON	Dofasco Inc. – Hamilton (100 MW)	P	2007-Q3	U	N	N
126	ON	Eastern Power – Greenfield 427 – Mississauga (284 MW)	P	2006-Q4	N	N	N
127	ON	Eastern Power – Greenfield 427 – Mississauga (330 MW)	P	2006-Q4	N	N	N
128	ON	Eastern Power – Greenfield 403 – Oakville (330 MW)	P	2006-Q4	N	N	N
129	ON	Echo Power Generation Inc. – Port Burwell (100 MW)	S	2005-Q4	U	N	N
130	ON	Enersource Hydro Mississauga for GTAA – Pearson International Airport (117MW)	C	2005-Q3	N	N	N
131	ON	Epcor Power Development Cor. – Applewood Power (310 MW) – Etobicoke/Mississauga	P	2007-Q4	U	N	N
132	ON	GAIA Power Inc. – Wolfe Island (300 MW)	P	2006-Q4	N	N	Y
133	ON	Invenergy Wind Canada – Lake St. Clair (688 MW)	P	2007-Q4	U	N	N
134	ON	Invenergy Wind Canada – Simcoe Wind Farm (200 MW)	P	2006-Q2	N	N	N
135	ON	Invenergy Wind Canada – Southgate Wind Farm (200 MW)	P	2006-Q3	Y	N	N
136	ON	Leader Wind Corporation – Kincardine (100 MW)	S	2005-Q4	Y	N	Y
137	ON	Leader Wind Corporation – Kincardine (300 MW)	P	2007-Q4	Y	N	N
138	ON	Northland Power Inc. – Thorold (273 MW)	S	2006-Q3	Y	Y	Y
139	ON	Northland Power Inc. – Kitchener-Fairview GS (192 MW)	P	2005-Q4	N	N	N
140	ON	Northland Power Inc. – Newmarket Steven Court GS (300 MW)	P	2006-Q4	U	N	N

	Area	Project Name	Status [1]	In-Service Date	Part of BPS [2]	Included in Last Area Review [3]	Included in NPCC Base Cases [4]
141	ON	Peninsula Engineering – Hamilton (130 MW)	P	2007-Q4	U	N	N
142	ON	Port Albert Wind Farms Ltd. – PAWF Phase IV 500 kV Connection (300 MW)	P	2007-Q1	Y		Y
143	ON	Pristine Power Inc – PPI Energy Project B (670 MW) – Lambton	P	2007-Q4	U	N	N
144	ON	Superior Wind Energy Inc. – Dunnville (100 MW)	P	2006-Q4	U	N	N
145	ON	Superior Wind Energy Inc. – Marathon (200 MW)	P	2006-Q3	N	N	N
146	ON	Superior Wind Energy Inc. – Prince Wind Farm (Phase 1 - 100 MW)	C	2005-Q4	N	N	N
147	ON	Superior Wind Energy Inc. – Prince Wind Farm (Phase 2 - 100 MW)	P	2006-Q4	N	N	N
148	ON	Superior Wind Energy Inc. – Shelburne (100 MW)	P	2006-Q4	N	N	N
149	ON	TransCanada Energy Ltd – Blackstone Power (1200 MW)	P	2008-Q1	U	N	N
150	ON	TransCanada Energy Ltd – Meadowvale Power (600 MW)	P	2007-Q4	Y	N	N
151	ON	Ventus Energy Inc. – Lakehead (100 MW)	P	2006-Q4	N	N	N
152	ON	Ventus Energy Inc. – Pays Plat (100 MW)	P	2006-Q4	N	N	N
153	ON	Ventus Energy Inc. – Thunder Bay (253 MW)	P	2007-Q4	N	N	N
154	ON	Ventus Energy Inc. – Michipicoten (100 MW)	P	2006-Q4	N	N	N
155	ON	AES Kingston Inc. – Kingston (50 MW)	P	2007-Q4	N	N	N
156	ON	AGSTAR Power Inc. – Tilbury (88 MW)	S	2005-Q4	N		Y
157	ON	AIM POWERGEN – Lake Erie Northshore (Phase 2 – 50 MW)	S	2007-Q1	N	N	N
158	ON	AIM POWERGEN – Lowbanks Wind Farm (90 MW)	P	2007-Q1	N	N	N
159	ON	Bay Area Health Trust – McMaster (12 MW)	S	2005-Q2	N	N	N
160	ON	Bay Shore Energy – Hamilton (85 MW)	P	2007-Q4	U	N	N
161	ON	Begetekong Power Corp – Umbata Falls (23 MW)	S	2007-Q1	N	N	N
162	ON	Canadian Hydro Developers – Melancthon Grey Wind Farm (Phase 1 - 75 MW)	S	2005-Q4	Y	N	Y
163	ON	Canadian Renewable Energy Corporation – Yellow Falls Generation (27 MW)	P	2007-Q4	N	N	N
164	ON	Energy Ottawa Inc. – Chaudierre Falls (20 MW)	P	2007-Q1	N	N	N
165	ON	Epcor Power Development Cor. – Kingsbridge Wind (40 MW) – Goderich	S	2005-Q4	N	N	N
166	ON	Fallsview Entertainment – Niagara Falls (66 MW)	P	2007-Q4	N	N	N
167	ON	GAIA Power Inc. – Wolfe Island (35 MW)	P	2005-	N	N	Y

	AREA	PROJECT NAME	Status [1]	In-Service Date	Part of BPS [2]	Included in Last Area Review [3]	Included in NPCC Base Cases [4]
				Q3			
168	ON	Hydro One Brampton – Brampton Brick (13 MW)	P	2007-Q4	N	N	N
169	ON	Hydro One for Ontario Power Generation – Tiverton Wind Farm (24 MW)	P	2005-Q3	N	N	N
170	ON	Hydro One for Schneider Power – Providence Wind (21 MW)	P	2005-Q3	N	N	N
171	ON	Lake Shore Energy – Haldimand County (65 MW)	P	2007-Q4	U	N	N
172	ON	Northland Power Inc. – Cambridge Generation MTS#1 (96 MW)	P	2005-Q4	N	N	N
173	ON	Northland Power Inc. – Grand Bend Wind Farm (86 MW)	P	2005-Q4	N	N	N
174	ON	Ontario Power Generation Inc. – Lac Seul GS (14MW)	P	2007-Q1	N	N	N
175	ON	Queens University - Kingston (15 MW)	P	2006-Q4	N	N	N
176	ON	Regional Power – Wawatay GS (7MW)	S	2005-Q3	N	N	N
177	ON	SUNCOR – Malahide Wind – Port Burwell (26 MW)	P	2005-Q4	N	N	N
178	ON	SUNCOR – Ripley Wind – Ripley (75 MW)	P	2005-Q4	Y	N	N
179	ON	Superior Wind Energy Inc. – Blue Highlands Wind Farm (Phase 1 - 50 MW)	C	2006-Q3	N	N	N
180	ON	Superior Wind Energy Inc. – Blue Highlands Wind Farm (Phase 2 - 75 MW)	P	2007-Q3	N	N	N
181	ON	Ventus Energy Inc. - Christian Island (51 MW)	P	2006-Q4	N	N	N
182	ON	Ventus Energy Inc. - Paisley (51 MW)	P	2006-Q4	N	N	N
183	ON	Veridian for Arbour Power – Ajax (53 MW)	P	2007-Q1	N	N	N
184	ON	Vision Quest – Reid's Corner (75 MW)	P	2005-Q2	Y	N	N
185	ON	Weyerhaeuser Company Ltd – Dryden (85 MW)	P	2007-Q1	N	N	N
186	ON	Install series capacitor on the 500 kV corridor between Hanmer and Essa	P	2006-Q4	U	N	N
187	ON	New 230 kV transmission between Armitage TS and Parkway TS	P	Under Review	U	N	N
188	ON	New Transformer Station Armitage 3 TS	P	2006-Q2	N	N	N
189	ON	New 115 kV underground transmission between John TS and Esplanade TS	S	2007-Q4	N	N	N
190	ON	St. Lawrence TS – provide radial transmission to Cornwall Electric	P	2006-Q2	N	N	N
191	ON	Vaughan Hydro – New Transformer Station Vaughan MTS 4	P	2008-Q2	N	N	N
192							
193							
194	QC	Grand-Brulé-Vignan 315 kV double-circuit line	W	2007	U	Yes (O/S)	Yes (O/S)

	AREA	PROJECT NAME	Status [1]	In-Service Date	Part of BPS [2]	Included in Last Area Review [3]	Included in NPCC Base Cases [4]
195	QC	Grand-Brûlé addition of two 1100 MVA 735/315 kV transformers	W	2007	U	Yes (O/S)	Yes (O/S)
196	QC	Hertel 315kV: One 345 MVAR Capacitor bank	I/S	2004	Y	No	Yes
197	QC	Duvernay 315kV One 345 MVAR Capacitor bank	I/S	2004	Y	No	Yes
198	QC	Duvernay 1650 MVA 735-315 kV Transformer (Phase II)	S	2009	Y	Yes	No
199	QC	Outarde-3 Upgrade (284 MW Hydro)	C	2003-6	N	Yes	Yes
200	QC	Toulnustouc (534 MW Hydro)	C	2005	N	Yes	Yes
201	QC	Toulnustouc – Micoua 315 kV line	C	2005	Y	Yes	Yes
202	QC	Toulnustouc incorporating substation	C	2005	N	Yes	Yes
203	QC	Toulnustouc Series Compensation at Bergeronnes	C	2005	N	Yes	Yes
204	QC	Jacques-Cartier 315 kV one 345 MVAR Capacitor Bank	C	2005	Y	Yes	Yes
205	QC	Le Suroit (800 MW CC)	W	2009	N	Yes	Yes (O/S)
206	QC	TransCanada Energy (547 MW CC)	C	2006	N	No	Yes
207	QC	Peribonka (385 MW Hydro)	C	2008	N	No	Yes
208	QC	Peribonka – Simard 161 kV line	S	2008	N	No	Yes
209	QC	Eastmain-1 (480 MW Hydro)	S	2006	N	No	Yes
210	QC	Eastmain – 1 – Nemiskau 315 kV line	S	2006	Y	No	Yes
211	QC	Outarde-4 Upgrade (160 MW Hydro)	C	2005-8	N	No	Yes
212	QC	Arnaud 1100 MVA 735/315 kV Transformer (Alouette Phase II)	S	2006	Y	No	Yes
213	QC	Boucherville 230kV : Two 190 MVAR Capacitor banks	I/S	2004	Y	No	Yes
214	QC	Duvernay 315kV : One 345 MVAR Capacitor bank (Eastmain 1)	S	2006	Y	No	Yes
215	QC	Dynamic shunt compensator (+250MVAR/-125MVAR)	S	2006	Y	No	No
216							

<u>Notations</u>:

(1) Status:
P – Proposed
S – Study is underway or complete
C – Under construction
I/S – In Service
O/S – Out of Service
R – Retired
W - Withdrawn

(2) Part of Bulk Power System (BPS): Y = Yes (Project is at least partially BPS), N = No, U = Undetermined

(3) Yes denotes that the project was included in the last Full or Intermediate Area Review.

Area	Last Full Area Review		Last Area Review			Current/Next Area Review	
	Year*	Approved**	Year*	Type	Approved**	Year*	Type
Maritimes	2001	11/2001	2004	Interim	9/2004	2005	tbd
New England	2000	5/2001	2003	Interim	9/2003	2004	Comprehensive
New York	2000	7/2000	2004	Intermediate	1/2005	2005	Comprehensive
Québec	2002	9/2002	2004	Interim	9/2004	2005	interim
Ontario	2002	1/2003	2004	Interim	1/2005	2005	tbd

* Year Review was conducted. Each Review evaluates a period of 4 to 6 years in the future.
** Date approved by TFSS.

(4) NPCC 2003-Series Future System (2009) Base Cases as updated April 1st, 2004.

The Major Project List includes significant proposed or planned generation and transmission projects within NPCC that have met the host Area's qualifications for inclusion in its next scheduled Area Transmission Review. Planned retirements of significant generation and transmission facilities also are listed. The list includes generation projects 100 MW or greater, reactive devices 100 MVAR or greater, and transmission projects 115 kV and above. Inter-Area projects are listed first, followed by the projects within each NPCC Area (projects within New Brunswick and Nova Scotia are listed separately). The Task Force on System Studies updates the list at least twice a year (in March and September) and more often as necessary. Projects are added to the list as they meet the necessary qualifications. Projects that go in-service are reported as such for one update cycle, and then removed in the following update. Retirements and withdrawn projects remain on the list until their status has been reflected in the host Area's Transmission Review and in the NPCC base cases.

APPENDIX F

LIST OF JOINT PROJECTS WITH INTER-REGIONAL IMPACTS IDENTIFIED IN AREA PLANS

IESO TABLE

Proponent	Queue Date	Location	Project Type	Proposed Size	Proposed I/S Date
HYDRO ONE NETWORKS INC.	22-Dec-98	Hawthorne TS/ Outaouais SS	Interconnection	1250	Uncertain
HYDRO ONE NETWORKS INC.	1-Aug-03	Parkway TS	New Supply Point	2 x 750 MVA	30-Jun-06
Hydro One Networks Inc.	2-Mar-04	Trafalgar TS	Reactive Compensation	300MVAr	1-May-05
HYDRO ONE NETWORKS INC.	24-May-02	Toronto	New Supply Point	Stg. 1 - 500 Stg. 2 - 500	30-Jun-10
HYDRO ONE NETWORKS INC.	20-Dec-02	Niagara	Transmission		30-Jun-06
Hydro One Networks	14-Jul-04	Essa TS	Reactive Compensation	245 Mvar	1-May-04
Canadian Hydro Developers Inc. - Melancthon Grey (Phase 1)	4-Feb-04	Southwest	Wind	75	30-Oct-05
Enersource Hydro Mississauga - Pearson International Airport	26-Nov-03	Toronto	Gas	117	30-Oct-05
AIM POWERGEN - Lake Erie Northshore (Phase 1)	22-Sep-03	West	Wind	100	31-Dec-05
Epcor Power Development - Kingsbridge Wind Farm	10-Dec-02	Southwest	Wind	40	31-Dec-05
Superior Wind Energy Inc. - Prince (Phase 1)	21-Apr-04	Northeast	Wind	100	31-Dec-05
Superior Wind Energy Inc. - Blue Highlands (Phase 1)	29-Nov-02	Southwest	Wind	50	30-Oct-05

Notes:

Only projects that are either under construction, committed or have a high likelihood of coming into service are included.

The list will be revised after the results of the Ontario Government RFP for 2500 MW Clean Air Generation are known.

Proposed in service dates are subject to change.

New England Control Area Proposed/Planned Generator Interconnections, Merchant and Elective Transmission Expansion in the Study/Interconnection Process (Not Yet Commercial) with Potential Impacts on Neighboring Control Areas In Order of Application for System Impact Study Agreement

Req. Type [1]	Request Date	Project Name	MW	Town or County	ST	ISO-NE Projected Commercial Operation Date	Proposed Point of Interconnection	SIS Com.	I.3.9 Apprvl.
G	2/16/1998	Meriden Power	544	Meriden	CT	TBD	Sectionalize 362 Line	Y	Y
G	1/5/1999	Redington Mountain Wind Farm	30	Carrabassett	ME	2005	Bigelow 115 kV Substation	Y	Y
G	7/24/2000	South Norwalk Repowering	50.4	S. Norwalk	CT	TBD	Norwalk 115 kV Substation	Y	Y
G	10/2/2000	Berkshire Wind Power Project	13	Hancock	MA	2005	Interconnecting to WMECO at Brodie Mt. In Lanesboro MA	Y	Y
ET	6/1/2001	Increase Orrington South Transfer Limit	TBD	N/A			N/A	Y	Y
G	6/6/2001	Cape Wind Tubine Generators	425	Nantucket Sound	MA	TBD	Near Barnstable 115 kV Substation		
G	11/21/2001	Kleen Energy Project	540	Middletown	CT	2007	Sectionalize 353 Line	Y	Y
G	6/3/2002	Redington Wind Farm Phase II	60	Redington	ME	2005	Bigelow 115 kV Substation		
G	8/8/2002	Millstone 3 Upgrade	50	Waterford	CT	TBD	Increase Existing Unit Capacity	Y	Y
G	12/12/2002	VT Yankee Nuclear Power Station Upgrade	120	Vernon	VT	2005	Increase Existing Unit Capacity	Y	Y
G	1/15/2003	Seabrook Power Uprate	90		NH	Phase I - 2005 Phase II - 2006	Increase Existing Unit Capacity	Y	Y
G	2/4/2003	Peabody Power	94	Peabody	MA	2007	C155 & B154 - 115 kV Lines	Y	Y
G	3/06/2003	Waterside Power - 180 MW	180	Stamford	CT	TBD	Waterside 115 kV		
G	3/18/2003	Ridgewood RI Generation	10	Johnston	RI	Phase I - 2003 Phase II - 2005	Johnston Substation Distribution System	Y	Y
G	5/12/2003	Hoosac Wind Project	28.5	Florida & Monroe	MA	2005	Line Y25S	Y	Y
G	6/12/2003	AWT Fitchburg Wind Project	12	Fitchburg	MA	TBD	Ashburnham No. 610 - 13.8 kV		
G	7/7/2003	UCONN COGEN Facility	24.9	Storrs	CT	2005	Mansfield 69 kV	Y	Y
G	10/27/2003	SNEW Summer '04 Temporary Generator	23.8	Norwalk	CT	TBD	Norwalk 27.6 kV		
G	11/10/2003	East Haven Wind Farm	6	East Haven	VT	TBD	Village of Lyndonville Elec. Dept. Distribution Sys.		
G	1/16/2004	Ridgebury Power	10	Ridgefield	CT	TBD	CL&P Distribution System		
G	5/10/2004	Univ. of NH - CHP	7.5	Durham	NH	2005	PSNH Dist. Sys./Madburry 115 kV		
G	6/22/2004	Third Taxing Dictrict Units 1, 2 & 3	6	Norwalk	CT	TBD	CL&P 27.6 kV Distribution System/Norwalk 115kV		
G	7/20/2004	Rand-Whitney Co-Gen	14	Montville	CT	TBD	CL&P Distribution System/Montville 115 kV	Y	Y
G	11/2/2004	Devon Station Redevelopment	340	Milford	CT	2010	Devon 115 kV Substation		
G	11/2/2004	Norwalk Harbor Station Redevelopment	550	South Norwalk	CT	2007	Norwalk Harbor 115 kV Station		
G	11/2/2004	Cos Cob Redevelopment	80	Greenwich	CT	2007	Cos Cob 115 kV Substation		
G	11/9/2004	Biomass	40	County-Cheshire	NH	2007	N-186, 115kV line between Vernon Road Tap and border with VT		
G	11/15/2004	Wind Project	25	Lempster (Sullivan County)	NH	2007	TBD		
G	2/11/2005	Biomass	42	Litchfield County	CT	2007	TBD		
G	2/28/2005	Turbine	16	Penobscot County	ME	2007	TBD		

[1] G = Generator, ET = Elective Transmission, PtP = Point-to-Point Transmission Service

Note: ISO-NE Projected Commercial Operation dates are subject to verification.

PJM TABLE

PJM data for Appendix E to NCSP

	AREA	Project Name	Point of Interconnection	MW	C / E	Status	In Service Date	Part of BPS	Included in Last Area Review	Included in NPCC Base Cases
		Generation								
	PJM-NY	East Towanda-Moshannon 230kV	East Towanda-Moshannon 230kV	70	Energy	S	12/05	Y	Yes	U
	PJM-NY	Karthaus 230kV	Moshannan-Milesburg 230kV	290	Capacity	S	6/08	Y	Yes	U
	PJM-NY	Union City 230kV	Erie South-Warren 230kV	301.5	Capacity	S	6/06	Y	Yes	U
	PJM-NY	Linden 230 kV	Linden 230 kV	750	Capacity	C	6/06	Y	Yes	U
	PJM-NY	Linden 138 kV	Linden 138 kV	436	Capacity	C	6/06	Y	Yes	U
	PJM-NY	Erie East 230 kV	Existing - Reconnect from NY to PJM at Erie East 230 kV	100	Capacity	S	2006	Y	Yes	U
		Merchant Transmission								
2.	PJM-NY	Neptune	Sayreville, NJ (PJM) to W. 49th St., NYC or Newbridge Rd., L.I.	790		S	6/07	Y	Yes	Yes (O/S)
	PJM-NY	Linden VFT	Linden, NJ (PJM) to New York City	300		S	6/07	Y	Yes	U

S - Study is underway or complete
C - Under construction
Y - Yes (Project is at least partially BPS)

U - Undertermined
Yes - Yes, project was included in the last PJM Area review

NYISO TABLE

Queue Pos.	Owner/Developer	Project Name	Date of IR	SP (MW)	Type/ Fuel	Location County/State	Interconnection Point	Utility	S	Studies Available	Proposed In-Service
3	PSEG Power NY	Bethlehem Energy Center	4/27/98	350	CC-NG	Albany, NY	Albany 115kV	NM-NG	12	SRIS	2005
13	East Coast Power	Linden 7	3/25/99	100	ST-NG	Richmond, NY-NJ	Goethals 345kV	CONED	4	None	2007/06
18	NYPA	Poletti Expansion	4/30/99	500	CC-NG	Orange, NY	Astoria 138kV	CONED	12	SRIS, FS	2006
20	KeySpan Energy, Inc.	Spagnoli Road CC Unit	5/17/99	250	CC-NG	Suffolk, NY	Spagnoli Road 138kV	LIPA	7	SRIS	2008-097
22	Calpine Eastern Corp.	Wawayanda Energy	6/10/99	500	CC-NG	Orange, NY	Coop Corn-Rock 345kV	NYPA	8	SRIS	2008
24	Reliant Energy	Astoria Repowering-Phase 1	7/13/99	367	CC-NG	Queens, NY	Astoria 138kV	CONED	7	SRIS	2010
25	ConEd of NY	East River Repowering	8/10/99	288	CC-NG	New York, NY	E. 13th St. 138kV	CONED	12	SRIS, FS	2005
29	Mirant	Bowline Point Unit 3	10/13/99	750	CC-NG	Rockland, NY	W. Haverstraw 345kV	CONED	8	SRIS	2008
31	SCS Energy, LLC	Astoria Energy	11/16/99	1000	CC-NG	Queens, NY	Astoria 138kV	CONED	12	SRIS, FS	2006-07
32	American National Power	Brookhaven Energy	11/22/99	580	CC-NG	Suffolk, NY	Holbrook-Brookhaven 138kV	LIPA	9	SRIS	2006
33	Glenville Energy Park	Glenville Energy Park	11/30/99	540	CC-NG	Schenectady, NY	Rotterdam 230kV	NM-NG	7	SRIS	2007
69	Besicorp/Empire State	Empire State Newsprint	7/14/00	660	CT-NG	Rensselaer, NY	Reynolds Road 345kV	NM-NG	7	SRIS	2007
70	Reliant Energy	Astoria Repowering-Phase 2	8/18/00	173	CT-NG	Queens, NY	Astoria 138kV	CONED	7	SRIS	2011
90	Fortistar, LLC	Fortistar VP	3/20/01	79.9	CT-NG	Richmond, NY	Fresh Kills 138kV	CONED	8	SRIS	2007
91	Fortistar, LLC	Fortistar VAN	3/20/01	79.9	CT-NG	Richmond, NY	Goethals/Fresh Kills 138kV	CONED	8	SRIS	2007
93	PSEG Power In-City I	Cross Hudson Project	5/11/01	550	CT-NG	New York, NY-NJ	W49th Street 345kV	CONED	9	SRIS	2008
94	Atlantic Energy, LLC	Project Neptune DC PJM-LI	5/22/01	660	DC	Nassau, NY-NJ	Newbridge Road 138kV	LIPA	7	SRIS	2007
103	Pegasus Trans. Co.	Niagara Reinforcement	8/15/01	1200	DC	Oneida - NY, NY	Marcy,Edic,Porter - W49th St.	NYPA/NM/CE	1	None	2009
106	TransGas Energy	TransGas Energy	10/5/01	1100	CT-NG	Kings, NY	E13St, Rainey, Farragut-345kV	CONED	7	SRIS	2008-09
107	Caithness Bellport	Caithness Bellport	10/9/01	310	CT-NG	Suffolk, NY	Brookhaven-Holbrook, H'ville	LIPA	5	None	2008
110	PG&E/Liberty Gen.	Liberty Generation	2/4/02	400	CT-NG	Richmond, NY-NJ	Goethals 345kV	CONED	7	SRIS	2007
111	River Hill Power Co.	River Hill Project	2/5/02	290	CT-NG	Chemung, NY-PA	Homer City -Watercure 345kV	NYSEG	5	None	2008
117	Chautauqua Windpower	Chautauqua Windpower	5/14/02	50	W	Chautauqua, NY	Dunkirk-S. Ripley 230kV	NM-NG	7	SRIS	2006
124	Bay Energy, LLC	Bay Energy Project	7/1/02	79.9	CT-NG	Kings, NY	Gowanus 138kV	CONED	7	SRIS	2007
125	East Coast Power	Linden VFT Inter-Tie	7/18/02	300	AC	Kings, NY-NJ	Goethals 345kV	CONED	4	None	2007
140	National Grid	Leeds-PV Reconductoring	8/26/03	N/A	AC	Greene-Dutchess, NY	Leeds/Athens-Pl. Valley 345kV	NM-NG	5	None	2006
141	Flat Rock Wind Power	Flat Rock Wind Power	8/27/03	300	W	Lewis, NY	Adirondack-Porter 230kV	NM-NG	7	SRIS	2005-06
144	Invenergy Wind, LLC	High Sheldon Windfarm	2/18/04	198	W	Wyoming, NY	Stolle Rd-Meyer 230kV	NYSEG	2	None	2006/08

NOTES: ? The column labeled 'SP' refers to the maximum summer megawatt electrical output.

? Type / Fuel. Key: ST=Steam Turbine, CT=Combustion Turbine, CC=Combined Cycle, H=Hydro, W=Wind, NU=Nuclear, NG=Natural Gas, O=Oil, C=Coal, D=Dual Fuel, AC=AC Transmission, DC=DC Transmission

? The column labeled 'S' refers to the status of the project in the NYISO's LFIP. Key: 1=Scoping Meeting Pending, 2=FES Pending, 3=FES in Progress, 4=SRIS Pending, 5=SRIS in Progress, 6=SRIS Approved/Regulatory Milestone Not Met, 7=FS Pending, 8=Rejected Cost Allocation/Next FS Pending, 9=FS in Progress, 10=Accepted Cost Allocation/IA in Progress, 11=IA Complete d, 12=Under Construction, 13=In Service for Test, 14=In Service Commercial, 0=Withdrawn

? Availability of Studies Key: None=Not Available, FES=Feasibility Study Available, SRIS=System Reliability Impact Study Available, FS=Facilities Strudy and/or ATRA Available

? Proposed in-service dates are shown in format Year/Qualifier, where Qualifie r may indicate the month, season, or quarter.

HYDRO-QUEBEC TRANSENERGIE

Hydro-Québec TransÉnergie has no projects at this time that would have inter-area impact.

The proposed 1250MW Ontario-Quebec interconnection project could be classified in this category, but the project is uncertain at this time.

NEW BRUNSWICK

New Brunswick has identified one project with inter-area impact:

Point Lepreau—Orrington, ME 345-kv line scheduled for 2006

APPENDIX G

LINKS TO

LOAD & CAPACITY REPORTS

FOR EACH REGION

LINKS TO LOAD AND CAPACITY TABLES FOR EACH REGION

REGION	LINK
IESO	http://www.ieso.ca/imoweb/monthsYears/monthsAhead.asp
ISO-NE	http://www.iso-ne.com/Historical_Data/CELT_Report/2004_CELT_Report/2004_CELT_Report.pdf
NEW BRUNSWICK	http://www.nbso.ca (website under development)
NYISO	www.nyiso.com/services/documents/planning/pdf/2004_gold_book.pdf
PJM	www.pjm.com/planning/res-adequacy/downloads/2004-load-report.pdf http://www.pjm.com/committees/planning/downloads/item3b-supplemental-analysis-04.pdf
HYDRO-QUEBEC TRANSENERGIE	http://www.hydro.qc.ca/distribution/en/marchequebecois/pdf/prev_ventes.pdf

APPENDIX H

FUTURE RETIREMENTS

TABLE OF FUTURE RETIREMENTS

REGION	UNIT NAME	TYPE	MW	DATE	Notes
IESO	Lakeview	Coal	1140	5/1/2005	
	Nanticoke	Coal	3920	12/31/2007	
	Lambton	Coal	1975	"	
	Atikokan	Coal	215	"	
	Thunder Bay	Coal	310	"	
	Bruce A Unit #3	Nuclear	769	1/1/2009	Subject to Future Evaluation
	Pickering B Units 5,6,7	Nuclear	516MW per Unit	1/1/2014	Subject to OPG Refurbishing Plans
ISO-NE	NONE				
NEW BRUNSWICK	NONE				
NYISO	Waterside Units #6,8,9	Gas/Oil	167MW Total	7/1/2005	Turbine/Gen Replacement
	Albany #1,2,3,4	Gas/Oil	356MW Total		Turbine/Gen Replacement
	Poletti 1	Gas/Oil	882MW	2/1/2008	Pending Station Repowering
	Russell #1,2,3,4	Coal	240MW Total	1/1/2007	Consent Agreement with NYS

	Huntley #63,64,65, 66	Coal	225MW Total	Summer 2005-Summer 2006	Consent Agreement with NYS
	Greenidge #3,4	Coal	160MW Total	12/31/2009	Conditional based upon evaluation of environmental requirements
	Westover #7,8	Coal	129MW Total	6/1/2007	Conditional based upon evaluation of environmental requirements
	Lovett #3,4,5	Coal	421MW Total	6/1/2007 (#3) 6/1/2008 (#4 & 5)	Conditional based upon evaluation of environmental requirements
PJM	See Following Table				
HYRDO-QUEBEC TRANSENERGIE	NONE				

PJM TABLE

PJM Generator Retirement Requests Updated 1/10/05

Summer 2004 Retirements

Unit	Capacity	Official Owner Request	Retirement	PJM Reliability Status
Hudson 3 CT	129	10/16/2003	10/16/2003	No Reliability Issues
Sayreville 4 & 5	229	11/1/2003	2/14/2004	Reliability Issues Identified and Resolved
Gould Street	101	11/4/2003	11/1/2003	No Reliability Issues
Seward 4 & 5	196	11/19/2003	11/19/2003	No Reliability Issues
Delaware 7	126	12/12/2003	3/1/2004	No Reliability Issues
Delaware 8	124	12/12/2003	3/1/2004	No Reliability Issues
Burlington 10	261	1/8/2004	4/4/2004	No Reliability Issues
VCLP NUG	46.6	2/2/2004	6/15/2004	No Reliability Issues
Gilbert 2 & 3 CTs	50	2/12/2004	Request Withdrawn	No Reliability Issues
Glen Gardner 2-4, 6-8 CTs	120	2/12/2004	Request Withdrawn	No Reliability Issues
Warren 3 CT	57	2/12/2004	5/1/2004, relisted from 7/1/04 until 10/1/04	No Reliability Issues
Wayne CT	56	2/12/2004	5/1/2004	No Reliability Issues
Werner 1-4 CTs	212	2/12/2004	Request Withdrawn	No Reliability Issues
Blossburg CT	19	2/12/2004	Black Start Unit operational until at least 12/05	Reliabililty Issue - Blackstart
Gilbert 1&4 CTs	48	2/12/2004	Black Start Unit operational until at least 12/05	Reliabililty Issue - Blackstart
Glen Gardner 1&5	40	2/12/2004	Black Start Unit operational until at least 12/05	Reliabililty Issue - Blackstart
Shawnee CT	20	2/12/2004	Black Start Unit operational until at least 12/05	Reliabililty Issue - Blackstart
Riegel Paper	27	6/11/2004	Planned to retire 6/30/04, request delayed until 12/31/04	No Reliability Issues
Total Requests	1861.6			

Blackstart (retained to 12/05)	134
Retirement/Mothball Withdrawn	439
Total Deferred/Withdrawn Requests	573
Final Summary for Summer 2004	
Actual pre-summer retirements	1288.6
Deferred/Withdrawn Requests	573

PJM Generator Retirement Requests Updated 1/10/05

Future Retirements - Page 1

Unit	Capacity	Official Owner Request	Requested Retirement Date	PJM Reliability Status
Martins Creek 1	140	3/19/2004	9/15/2007	No Reliability Issues
Martins Creek 2	140	3/19/2004	9/15/2007	No Reliability Issues
Warren 3 CT	57	2/12/2004	Mothballed on 5/1/2004, relisted from 7/1/04 until 10/1/04	No Reliability Issues
Riegel Paper	27	6/11/2004	Planned to retire 6/30/04, request delayed until 10/1/04	No Reliability Issues
Collins 1 (NICA)	554	6/2/2004	12/31/2004	No Reliability Issues
Collins 2 (NICA)	554	6/2/2004	3Q/4Q 2004	No Reliability Issues
Collins 3 (NICA)	530	6/2/2004	12/31/2004	No Reliability Issues
Collins 4 (NICA)	530	6/2/2004	ASAP	No Reliability Issues
Collins 5 (NICA)	530	6/2/2004	ASAP	No Reliability Issues
Sewaren 1	104	9/8/2004	12/7/2004	Reliability Issues Identified - Unit retained through summer 2006
Sewaren 2	118	9/8/2004	12/7/2004	Reliability Issues Identified - Unit retained through summer 2006
Sewaren 3	107	9/8/2004	12/7/2004	Reliability Issues Identified - Unit retained through summer 2006
Sewaren 4	124	9/8/2004	12/7/2004	Reliability Issues Identified - Unit retained through summer 2006
Hudson 1	383	9/8/2004	12/7/2004	Reliability Issues Identified - Unit retained through summer 2006
Kearny 7	150	9/8/2004	12/7/2004	Reliability Issues Identified - Unit retained through summer 2005
Kearny 8	150	9/8/2004	12/7/2004	Reliability Issues Identified - Unit retained through summer 2005
B L England 1	129	9/21/2004	12/15/2007	Reliability Issues Identified
B L England 2	155	9/21/2004	12/15/2007	Reliability Issues Identified
B L England 3	155	9/21/2004	12/15/2007	Reliability Issues Identified
B L England IC1	2	9/21/2004	12/15/2007	Reliability Issues Identified

B L England IC2	2	9/21/2004	12/15/2007	Reliability Issues Identified
B L England IC3	2	9/21/2004	12/15/2007	Reliability Issues Identified

PJM Generator Retirement Requests Updated 1/10/05

Future Retirements - Page 2

Unit	Capacity	Official Owner Request	Requested Retirement Date	PJM Reliability Status
B L England IC4	2	9/21/2004	12/15/2007	Reliability Issues Identified
STI 3	10	9/29/2004	1/1/2005	No Reliability Issues
STI 4	10	9/29/2004	1/1/2005	No Reliability Issues
Crawford 31	59	10/12/2004	ASAP	Reliability issue identified and resolved
Crawford 32	58	10/12/2004	ASAP	Reliability issue identified and resolved
Crawford 33	59	10/12/2004	ASAP	Reliability issue identified and resolved
Calumet 31	56	10/12/2004	ASAP	No Reliability Issues
Calumet 33	42	10/12/2004	ASAP	No Reliability Issues
Calumet 34	51	10/12/2004	ASAP	No Reliability Issues
Electric Junction 31	59	10/12/2004	12/31/2004	No Reliability Issues after 1/1/05
Electric Junction 32	59	10/12/2004	12/31/2004	No Reliability Issues after 1/1/05
Electric Junction 33	59	10/12/2004	12/31/2004	No Reliability Issues after 1/1/05
Joliet 31	59	10/12/2004	ASAP	No Reliability Issues
Joliet 32	57	10/12/2004	ASAP	No Reliability Issues
Lombard 32	31	10/12/2004	ASAP	No Reliability Issues
Lombard 33	32	10/12/2004	ASAP	No Reliability Issues
Sabrooke 31	25	10/12/2004	12/31/2004	No Reliability Issues
Sabrooke 32	25	10/12/2004	12/31/2004	No Reliability Issues
Sabrooke 33	24	10/12/2004	12/31/2004	No Reliability Issues after 1/1/05
Sabrooke 34	13	10/12/2004	12/31/2004	No Reliability Issues after 1/1/05
Bloom 33	24	10/12/2004	ASAP	No Reliability Issues
Bloom 34	26	10/12/2004	ASAP	No Reliability Issues
Deepwater CT A	19	10/13/2004	4/1/2005	Blackstart Plans Under Review
Madison St. CT	10	10/13/2004	12/31/2004	No Reliability Issues
Total	5512			