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**Restoration of the NPCC Areas Following  
the Power System Collapse of August 14, 2003**

**Prepared by:**

**NPCC Inter-Control Area Restoration  
Coordination Working Group (CO-11)**



**NPCC Inter-Control Area Restoration Coordination Working Group**

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## **1.0 Executive Summary**

The NPCC Inter-Control Area Restoration Coordination Working Group (IRCWG) was charged to assess the restoration efforts of the NPCC Areas impacted by the power system collapse of August 14, 2003, which included large portions of Ontario and New York as well as portions of New England (Reference Appendix A for the scope of activities of the IRCWG).

The restoration process following the unprecedented loss of load on August 14th was effectively and successfully carried out by system operators well trained to cope with such an event.

In the report following, each of the three impacted Areas provides an overview of their experiences, focusing on the following critical elements of power system restoration:

- Required operations to stabilize remaining islands;
- Effectiveness of Area restoration procedures, annual exercises, Area training, NPCC criteria and procedures and NPCC Training Seminars in responding to the events of August 14th;
- Effectiveness of communications within and between NPCC Areas and with neighboring Regions;
- Ability to readily and clearly identify the status of one's own Area as well as that of neighboring Areas and Regions;
- Synchronizations within and between the NPCC Areas and with neighboring Regions;
- Identification of high level restoration milestones, such as the use of manual load shedding to achieve stabilization, the time for the restoration of the transmission system, the time for the restoration of load, the time for the restoration of interconnections, dependence on, or ability to supply, emergency power deliveries and a summary of the utilization of emergency procedures; and
- Events occurring within the restoration process unique to the Areas are also highlighted.

Each Area concludes its section with a summary of the lessons learned and recommendations to be adopted by the Area following its analysis of the August 14th restoration. Based on the individual Area lessons learned and recommendations, NPCC Region-wide recommendations, to be pursued by all members of NPCC, have been developed and prescribed. Implementation of these recommendations will serve to facilitate successful NPCC inter-Area restoration on a Region-wide basis following system disturbances in the future.

Section 4.0 of this report provides a broad overview of the sequence of events within the NPCC Areas occurring on August 14<sup>th</sup> which led to the large loss of customer demand in Ontario, New York and New England. However, this report does not

describe the cause of the power system disruptions, as such detail is available in several published reports as enumerated in Appendix B.



## **2.0 Assessment of the NPCC Restoration Effort**

As each NPCC Control Area was in the process of assessing the current state of its area and that of its neighboring Control Areas, efforts immediately began to initiate the restoration process. The restoration effort following the power system collapse of August 14, 2003, was generally timely and effective. No further collapse of the system was generated as the interconnected bulk power system was re-synchronized, and virtually all demand was restored within thirty hours. The NPCC Region separated from the Eastern Interconnection primarily at the interfaces between PJM and the NYISO and between Michigan and the IMO. Internal to NPCC, the IMO was the most severely impacted Control Area, with a large portion of the province blacked out; only northwestern Ontario and several small load and generation pockets remained in service, with generation facilities at each end of Lake Ontario remained connected to Ontario and New York load. The NYISO experienced a wide spread outage in the southeastern portion of New York state, south and east of the Total East interface. The NYISO separated from the Eastern Interconnection predominantly along the PJM-NYISO interface, with the exception of some northern New Jersey load that was left isolated on the NYISO system. Two large hydro facilities and the Hydro-Québec HVdc tie were the major facilities that remained in service, providing power to the remaining upstate load and the isolated northern New Jersey load. The ISO-NE separated from the NYISO primarily along its interface with New York, isolating the bulk of the ISO-NE and the Maritimes Control Area from the Eastern Interconnection. Portions of southeastern Connecticut remained connected to New York and collapsed with the southeastern New York area, and some New York load remained connected to the Vermont system of the ISO-NE. With the exception of the load lost in southeastern Connecticut and smaller pockets in Vermont, the ISO-NE remained largely intact. Within the Maritimes Control Area, New Brunswick Power observed the operation of its “Loss of Line 3001” special protection system due to the frequency excursions experienced.

From an NPCC perspective, the initial focus was to re-synchronize to the Eastern Interconnection, with the NYISO attempting to re-establish ties with PJM. The NYISO initiated communications with PJM and successfully re-synchronized with the Eastern Interconnection at 18:52 on August 14<sup>th</sup> through an automatic synchro-check relay on the Erie East (PJM) to South Ripley (NY) 230 kV tie line. The second tie, and the primary interconnection to PJM and the Eastern Interconnection, was established at 19:06 through the Ramapo 345 kV station, providing a stronger link between the PJM 500 kV transmission network and the NY 345 kV transmission network and accordingly a stronger system to support the continuing NY and IMO restoration process.

Following this effort, the ISO-NE and the NYISO worked to re-synchronize New England to New York. The two Control Areas agreed to make the initial attempt through the Alps (NY) to Berkshire (NE) to Northfield (NE) tie, with the synchronization at the Northfield generating station. In an effort to gain better voltage

control to support the effort, the NYISO energized a 345 kV loop from its southern tier, into the Albany area (Alps) and continuing through the northern portion of the Con Ed service territory. At 01:53 on August 15<sup>th</sup>, the ISO-NE and the NYISO successfully re-synchronized at the Northfield station. At this point, all of the NPCC Areas, the IMO, the NYISO, the ISO-NE, Québec and the Maritimes Area were now successfully re-connected with the Eastern Interconnection. As the restoration effort continued in the IMO, the NYISO and the ISO-NE, Area to Area tie flows were carefully monitored to insure continuing load and generation as the restoration proceeded, and emergency assistance was provided among the NPCC Areas as required and as available.

For the Independent Electricity Market Operator (IMO-Ontario Area) and the New York Independent System Operator (NYISO-New York Area), which were severely impacted by the power system collapse, a critical element to their success restoration was the rapid restoration of the basic minimum power system. A basic minimum power system is a transmission system that consists of one or more generating stations, transmission lines, and substations operating in the form of an island, permitting it to be re-started independently and subsequently re-synchronized to other islands or the main bulk power system. The transmission elements of the basic minimum power system connect units which have blackstart capability to those units without blackstart capability and include selected tie lines and corresponding sub-stations judged to be essential to the formation of the larger power system.

The two Areas of NPCC which were severely disrupted on August 14<sup>th</sup> established their respective basic minimum power systems as follows:

IMO	13 hours
NYISO	10 hours

Ultimately, the transmission systems in all three impacted NPCC Areas were effectively restored in their entirety as follows:

IMO	26 hours
New York ISO	30 hours
ISO-NE	9 1/2 hours

The restoration times above reflect the extent of the restoration efforts required within each Area.

The overall restoration effort in NPCC was successfully realized in large measure by having in place mandatory reliability criteria requiring restoration plans within each NPCC Area as well as the testing of the key facilities and associated critical components necessary to establish a basic minimum power system for the purposes of restoration following a major system interruption. NPCC also significantly benefited on August 14<sup>th</sup> due to the clear lines of authority present in each NPCC Area directing the control of the bulk power system as well as the restoration process itself. Rigorous

and enforceable criteria, and well defined authority, must be retained as the industry transitions to the NERC Reliability Functional Model.

Nevertheless, the complexity of reliably restoring supply to 48,000 MW of load in a timely manner identified the need for improvements in various areas, which are captured in the recommendations following in section 3.0.

### **3.0 NPCC Recommendations**

These recommendations were derived by the NPCC Inter-Control Area Restoration Coordination Working Group in consideration of those determined from the individual Area reports and the contributions from system operators attending the NPCC System Operators Seminar held on May 5 and 6, 2004. These recommendations are considered to be applicable to all NPCC Areas on a Region-wide basis, and it should be noted that there is no implied hierarchy in the order in which they are presented.

#### **3.1 Procedures and Training**

##### **3.1.1 Synchronizing of Electrical Islands**

The IRCWG recommends that guidelines for matching voltage and frequency for the manual re-synchronization of electrical islands be developed and incorporated in the “NPCC Inter-Control Area Power System Restoration Reference Document.” These guidelines are then to be incorporated in each Area restoration plan to facilitate Area to Area re-synchronization, where applicable.

##### **3.1.2 Inadvertent Re-Synchronization**

The IRCWG recommends that each Area review the synchronizations made between electrical islands by automatic re-closing and determine if these re-closures were: a) appropriate ; b) consistent with the normal, steady state design intent of the automatic re-closing systems; c) acceptable for the rare event which occurred on August 14, 2003. The IRCWG recommends that the inadvertent synchronizations done manually be investigated, and methods to avoid manual inadvertent synchronizations in the future should be identified. Results should be incorporated into switching procedures and training.

##### **3.1.3 Stabilization of Surviving Electrical Islands**

The NPCC Inter-Control Area Restoration Coordination Working Group recommends that each Area review its restoration plan to address the actions necessary to stabilize operations in the remaining electrical islands following a major system separation.

##### **3.1.4 Load Shedding**

The NPCC Inter-Control Area Restoration Coordination Working Group recommends that each Area ensure that its load shedding capability remains, where applicable, viable in restoration situations following a major system disruption.

### **3.1.5 Operator Authority**

The NPCC Inter-Control Area Restoration Coordination Working Group recommends that each Area continue to emphasize in its system operating procedures, job descriptions and operator training that its system operators possess the authority to take any action required, including load shedding, to comply with the NPCC Criteria and NERC requirements.

### **3.1.6 Restoration Training**

The NPCC Inter-Control Area Restoration Coordination Working Group recommends that NPCC develop plans for inter-Area restoration training drills, including those participants critical to restoration (such as Transmission Operators and Satellite Control Centers), simulating the restoration, the scope of which can include whole or partial Areas.

## **3.2 Communications**

### **3.2.1 Communications Management**

The NPCC Inter-Control Area Restoration Coordination Working Group recommends that each Area review its voice telecommunication facilities and procedures to identify means to better; 1) manage call volume information, 2) prioritize communications and, 3) disseminate necessary information during major system emergencies.

## **3.3 Tools**

### **3.3.1 Alarm Management**

The NPCC Inter-Control Area Restoration Coordination Working Group recommends that each Area review the ability of its Energy Management System (EMS) to buffer and prioritize alarms during a major system disturbance.

### **3.3.2 Wide Area View**

The NPCC Inter-Control Area Restoration Coordination Working Group recommends that each Area provide its system operators with enhanced capabilities to permit a wide area view which will permit a more rapid assessment of the state of the interconnected bulk power system following a large scale system disturbance.

### **3.4 Criteria and Compliance**

#### **3.4.1 Testing of Key Facilities and Associated Critical Components**

NPCC Document A-03, “Emergency Operation Criteria,” defines a comprehensive program to identify, monitor and test the key facilities and associated critical components required to establish a basic minimum power system for purposes of restoration. The IRCWG recommends that this testing program be further strengthened by incorporating these criteria requirements in NPCC Document A-08, “NPCC Reliability Compliance and Enforcement Program.”

#### **3.4.2 Restoration Criteria and Guides**

The IRCWG recommends that the NPCC Document A-03, “Emergency Operation Criteria,” and the “NPCC Inter-Control Area Power System Restoration Reference Document” be reviewed to incorporate lessons learned from the restoration efforts.

#### **3.4.3 Fuel Supply for Emergency Generators**

The IRCWG recommends that the NPCC Document A-03, “Emergency Operation Criteria,” be modified to add a requirement to address adequate on-site fuel supplies for stand-by emergency generators associated with key facilities for restoration.

#### **4.0 Impact of the Power System Collapse of August 14, 2003, on NPCC**

On August 14, 2003, a cascading series of transmission and plant contingencies outside the boundaries of NPCC led to major power outages in Ontario, New York and parts of New England as well as the separation of the majority of New England and all of the Maritimes from the remainder of the system. In addition, although Hydro-Québec TransÉnergie (TE) lost a portion of its exports to the IMO, the NYISO and the ISO-NE at the time of the disturbance, the TE transmission system sustained the loss of these exports without significant impact.

The Reliability Coordinators of NPCC had no advance warning of the problems evolving in the Eastern Interconnection beyond the borders of NPCC. The sequence of events experienced by the NPCC Region culminated in the break-up of the bulk power grid and loss of 48,000 MW of load in NPCC within the span of a few seconds.

At approximately 16:09 EDT, the NPCC region experienced a significant change in power flows and frequency, which would prove to be the first indication of the events to follow. Prior to the appearance of this first swing, power flows in the NPCC Region, including its portion of the Lake Erie transmission loop, were typical for the summer period, and within acceptable limits. Transmission and generation facilities were in a secure state in all of NPCC. The critical events that occurred within the NPCC Areas were as follows:

At about 16:09, an increase in power flow from Pennsylvania, through New York and Ontario, and into Michigan was experienced.

Shortly afterward, between 16:10:38 and 16:10:41, a sudden large surge of power from Pennsylvania, through New York and Ontario, and into Michigan, concurrent with a sudden extraordinary increase in system frequency to 60.3 Hz, resulted in the beginning of circuit trips along the border between the Pennsylvania-New Jersey-Maryland Interconnection (PJM) and the NYISO. At the same time, power surged into New England and the Maritimes region of Canada. The combination of this power surge and the frequency rise resulted in the rejection of 380 MW of pre-selected Maritimes generation due to the operation of the New Brunswick Power “Loss of Line 3001” special protection system monitoring the status of system frequency and export flows on the 345 kV interconnection between the Maritimes and New England.

Between 16:10:42 and 16:10:45, the western PJM-NYISO 345 kV and 230 kV interconnections rapidly tripped in a west to east direction, followed immediately by the trip of the Branchburg - Ramapo 500 kV tie into the southeastern New York region. One out of three in-service tie lines between Ontario and Michigan was lost when Keith - Waterman 230 kV line tripped. Northwestern Ontario also separated from the rest of Ontario at this time, leaving Northwest Ontario loads fed from the Eastern Interconnection via the

Manitoba and Minnesota systems. Northeast New Jersey separated from the remainder of New Jersey, but remained tied to New York through the South Mahwah – Waldwick 345 kV and Hudson – Farragut 345 kV circuits. NPCC was then separated from the Eastern Interconnection but continued to supply power, via Ontario, into the eastern Michigan and northern Ohio load pocket, which had already separated from the Eastern Interconnection.

Over the period 16:10:46 to 16:10:49, a large power surge from New England to New York on their tie lines resulted in the effective separation of these Areas. At the same time, Vermont lost approximately 140 MW of load, and southwest Connecticut became isolated onto the New York system. The remainder of the New England Area and the entire Maritimes Area continued to operate as an electrical island. Within the same time interval, the State of New York effectively separated into eastern and western islands along the Central East/Total East transmission interfaces, with northeast New Jersey and southwest Connecticut tied to the eastern island.

Over the time period from 16:10:49 to 16:10:50, frequency declined below 59.3 Hz in parts of NPCC, initiating, as designed, automatic underfrequency load shedding in Ontario, eastern New York and southwestern Connecticut. In addition, large power swings between New York and Ontario resulted in the loss of nine internal 230 kV lines in Ontario, separating most of Ontario from New York and leaving the Ontario Beck and Saunders hydro stations radially connected to the western New York electrical island.

Between 16:10:50 and 16:10:56, the isolation of the Ontario hydro units onto the western New York island, coupled with underfrequency load shedding in the western New York island, caused the frequency in this island to rise to 63.0 Hz. At the same time, the now extremely generation deficient Ontario island frequency continued to decline towards 58.8 Hz, the threshold for the second stage of Underfrequency Load Shedding.

Between 16:10:56 and 16:11:11, three 230 kV lines re-closed automatically in Ontario, re-connecting western New York to Ontario; a few seconds later, Stage II of the underfrequency load shedding program activated in both Areas. After fourteen seconds the three lines that had automatically re-closed tripped a second time. With Ontario still supplying 2,500 MW to the Michigan-Ohio load pocket (until 16:11:57, when two remaining tie lines between Ontario and Michigan tripped), the Ontario system frequency declined towards a widespread shutdown at 16:11:58, resulting in the widespread loss of power to Ontario, including the cities of Toronto and Ottawa.

At 16:11:22, New England's Long Mountain to Plumtree 345 kV line tripped, leaving Southwest Connecticut connected to Northport, New York (Long Island), through the Norwalk Harbor to Northport 138 kV 1385 submarine cable across Long Island Sound. About two seconds later, at 16:11:24, the two 345



kV circuits connecting southeastern New York to Long Island tripped. This islanded Long Island and the southwestern Connecticut areas, which remained tied together by the 1385 cable. At 16:11:45, the Norwalk Harbor to Northport 138 kV 1385 cable tripped, leaving the generation deficient southwest Connecticut and Long Island areas destined to collapse.

Within the western New York island, the boundary of which was slightly modified as a result of the re-closure of Fraser to Coopers Corners 345 kV at 16:11:23, the 345 kV system remained intact between the Niagara and Utica areas, and the St. Lawrence area remained connected to the Utica area through both the 765 kV and 230 kV circuits. Ontario's Beck and Saunders generation remained connected to New York at Niagara and St. Lawrence, respectively, and this island stabilized and remained intact throughout the disturbance.

As a result of the severe frequency and voltage changes, many large units in both New York and Ontario tripped. The eastern island of New York lost the heavily populated areas of southern New York, including New York City, Long Island and the northern New York City suburbs. At 16:11:29, the New Scotland to Leeds 345 kV path tripped, splitting the northern and southern sections of the eastern New York island. The northern portion of the eastern island (the Albany area) shed load and remained electrically alive until it could be synchronized with the western New York island.

At this point Ontario, New York and New England began the task of stabilizing the remaining electrical islands, restoring the transmission system and ultimately restoring customer load. Summaries of the restoration efforts of each of the impacted NPCC Areas, together with the lessons learned during these experiences, and corresponding recommendations, follow.

## **5.0 Restoration of Ontario**

### **5.1 Introduction**

In spite of the many challenges during restoration, throughout the entire emergency there was excellent co-operation amongst Restoration Plan Participants who took the necessary actions and in many cases displayed perseverance and ingenuity under trying circumstances. Although some delays were encountered as obstacles were identified and overcome, at no time were errors made that resulted in further system collapse, caused equipment damage or jeopardized employee or public safety. The IMO also acknowledges the assistance and cooperation of Ontario's inter-connected neighbors who helped mitigate the capacity and energy emergency during the days following the restoration of Ontario's integrated power system. The Market Rules for the Ontario Electricity Market require that all Market Participants, including Restoration Plan Participants, review their emergency preparedness plans annually, and submit these revised plans to the IMO for review. In light of our experiences as a result of the August 14, 2003 blackout, the IMO anticipates reviewing these revised plans which would be expected to identify actions underway to improve emergency response capability. In addition, the IMO looks forward to continuing to work with Market Participants to conduct restoration training and exercises. As Dave Goulding, President and CEO of the IMO, noted in his testimony before the U.S. House of Representatives Committee on Energy and Commerce shortly after the blackout:

*“We confirmed that maintaining a well-documented restoration plan, supported by training and rehearsals involving the IMO, market participants and government, was and will continue to be a key investment.”*

### **5.2 System Conditions Before the Event and Start of Restoration**

#### **A. Pre-Event System Conditions**

Immediately prior to the blackout, the IMO-controlled grid was in a normal operating state with a seasonably warm temperature of 31 degrees Celsius and an Ontario demand of 24,050 MW. A peak demand of 24,400 MW was forecast for later that day. Scheduled imports were well below the approximately 4,000 MW import capability. Some equipment was out of service on planned outages. These conditions were not unusual and not extreme compared with conditions experienced on many other similar days during the summers of 2002 and 2003.

- All flows on the transmission system were within their respective operating security limits including all transmission circuit continuous thermal ratings;
- Transmission system voltage levels were within their acceptable ranges including the reactive power output of generating units;

- All operating reserve criteria were being met, and sufficient resources were scheduled to meet the demand and operating reserve obligations for the evening peak; and
- Scheduled imports and actual flows were well within the capabilities of the interconnections with no transmission loading relief procedures in effect to reduce any interface flows.

## **B. The Blackout and the Impact on Ontario**

### **Ontario Power System Conditions Immediately Following the Blackout**

Immediately after the system collapse at 4:11 PM EDT, most of Ontario was blacked-out with the exception of northwestern Ontario and several small islands of load and generation. Northwestern Ontario load and generation was unaffected by the blackout, but the transmission to the rest of Ontario was automatically disconnected. Most generating facilities in the rest of Ontario tripped off-line as protective equipment operated. Generating facilities at each end of Lake Ontario remained connected to Ontario and NYISO load. About 1,200 MW of Ontario load remained supplied with electricity, most of it in northwestern Ontario.

The impact on Ontario was particularly acute, resulting in a load loss of about 23,000 MW out of an expected peak for that day of 24,400 MW. As a result of the blackout, the IMO suspended the Ontario electricity market and implemented the Ontario Power System Restoration Plan (OPSRP). Much of the IMO-controlled grid was restored within about thirteen hours, and most customers were re-connected within about thirty hours. However, it became evident that insufficient generation capacity would be available through much of the following week. The Government of Ontario declared a Provincial emergency on Thursday evening, August 14th, and on Sunday requested that all Ontario residential, commercial and industrial consumers reduce their energy consumption by 50%. The scope of the blackout was similar to emergency exercise scenarios played-out during IMO coordinated restoration exercises conducted in eastern Ontario in 2001 and Western Ontario in 2002. However, this was the first time, simulated or real, that, with the exception of those in northwestern Ontario, all the 85 Restoration Plan Participants were involved in restoring the IMO controlled grid. Both Michigan and the NYISO, two of the largest systems that Ontario exchanges electricity with, were also significantly blacked out. Considering the scale of the blackout, the unknown cause, and uncertain conditions immediately following the blackout, the objectives of the Ontario Power System Restoration Plan (OPSRP) to restore the IMO-controlled grid were successfully achieved through the cooperation of the Restoration Plan Participants. The OPSRP is a strategic plan intended to be effective through any contingency event, regardless of circumstances. The blackout demonstrated that the Plan was fundamentally sound.

The province of Ontario has in place in accordance with the Electricity Act, s. 1998, an Emergency Preparedness Task Force (EPTF) to plan for and mitigate electricity

emergencies. The EPTF is chaired by the IMO and includes key representatives from the electricity sector including the government's Ministry of Energy representative. The EPTF mandated and sponsored a Restoration Working Group led by the IMO to analyze the blackout and subsequent restoration to identify lessons learned and opportunities for improvement. The Restoration Working Group (RWG) assessed that the Ontario grid was restored safely and in a timely manner, recognizing the severity of the blackout and the challenges encountered. As would be expected for an event of this magnitude, there is opportunity for improvement in a number of areas. Some improvements are related to the planning process itself, but most relate to improving the capability of the Restoration Plan Participants to implement the plans in an effective and timely manner.

### **Nine Days of Emergency Operation**

The blackout caused most Ontario generators to trip off-line. Many generators were re-started and all connected load was restored within the first 26 hours as grid supply became available. This timely restoration mitigated the immediate concern for public health and safety. However, even with grid supply restored, as a result of the initial trip, some generators could not return to service for several days until equipment was made ready to return to reliable service. The resulting generation shortage aggravated the already tight supply situation in Ontario. With hot weather forecast for the following week, and with electricity supply assistance from Ontario's neighbors uncertain, it became apparent that it would be some days before adequate generating capacity would be available to supply Ontario's normal demand for electricity. Therefore, system restoration and operations efforts strived to maximize available generation.

On August 14<sup>th</sup>, the recently installed temporary generators (approx. 250 MW) contracted by Ontario Electricity Finance Corporation (OEFC) were started, and at the IMO's request, operated beyond their 4-hour daily limit. These generators were installed to supplement capacity during periods of high demand lest energy / capacity emergencies be encountered

Late Thursday and into Friday, with the restoration continuing and the IMO still in an EEA3 (NERC defined Energy Emergency Alert-Level 3), several hydroelectric and thermal generators were synchronized, and three Bruce Power and one Ontario Power Generation (OPG) Darlington nuclear units were loaded. Imports were maximized while the inter-ties with Michigan remained opened. On Friday, all transmission, except the Michigan ties were restored by 18:26. Through rotational load shedding, loads served by distributors were restricted to approximately 75% of normal until 22:40 when all loads were restored. A 5% voltage reduction remained in effect. Peak load reached 16,652 MW by 22:00.

On Saturday, August 16<sup>th</sup>, the EEA3 was changed to an EEA2, and the 5% voltage reduction was lifted.

At a press conference on August 17<sup>th</sup> at 10:00 AM EDT, the Government of Ontario issued an urgent appeal to all consumers to reduce their use of electricity by 50% for the duration of the provincial emergency. The demand response to the appeal was substantial. For example, as much as 4,000 MW of curtailment and conservation is estimated to have occurred over the peak hour on August 19, 2003.

Additional nuclear generators at Darlington and Pickering Generating Stations (GSs) came back into service throughout the remainder of the week and a peak demand of 20,726 MW was reached on August 21<sup>st</sup>. Emergency imports were obtained when requested, and the OEFC temporary generators were dispatched each day up to and including August 21<sup>st</sup>.

The IMO remained in an EEA 2 state until August 22, 2003. The provincial emergency lasted for nine days and was terminated by the Government of Ontario at 20:00 EDT on August 22<sup>nd</sup>. The IMO-administered market resumed operation at midnight 00:00 EST on August 23, 2003.

### **5.3 System Restoration**

#### **A. Stabilization of the Remaining Islands**

##### **Restoration Priorities**

The overall objective of the Ontario Power System Restoration Plan (OPSRP) is to regain a reliable integrated power system by restoring the IMO-controlled grid to the maximum extent and as quickly as possible.

Throughout the restoration process, voltage and frequency must be carefully managed so as not to adversely affect customer and power system equipment. It is also important that, during each of the many sequential steps required to restore the system, the likelihood of further collapse is minimized.

The priorities of the Restoration Plan are:

- 1) Restoration of power-system-supplied Class IV AC power to all nuclear sites connected to the IMO-controlled grid as soon as possible to maintain the integrity of nuclear units, and to make them available as soon as possible to assist in subsequent restoration of the power system;
- 2) Restoration of power-system-supplied AC power to critical transmission station and generating station service loads that supply equipment necessary to facilitate the rapid restoration of the power system;
- 3) Restoration of power-system-supplied AC power to critical utility-owned telecommunications facilities throughout the province;
- 4) Restoration of customer loads to the extent necessary to control voltages and secure operating generation units during the early stages of system restoration;  
and

- 5) Synchronization of stable and balanced islands of generation and load with other parts of the IMO-controlled grid, or to adjacent power systems, at the earliest opportunity in a controlled fashion.

These priorities were appropriately and successfully maintained throughout the restoration process, in spite of many changing conditions.

### **Restoration Activities**

After the collapse of the IMO-controlled grid, the IMO's immediate attention was given to determining the extent of the disturbance and implementing the objectives and priorities of the Ontario Power System Restoration Plan. The IMO-controlled grid was found to consist of five relatively small electrical islands of load and generation:

- an island of approximately 720 MW of Saunders generation carrying 40 MW of Ontario load with the rest supplying the NYISO in an island;
- Beck 1 and 2 generation serving 300 MW of Ontario load and providing 900 MW to the NYISO in an island;
- generation and load in Northwestern Ontario (west of Wawa) which remained attached to the Manitoba and Minnesota systems;
- 30 MW load at Spruce Falls supplied by Smoky Falls generating units; and
- 20 MW of Des Joachims generating units and local load.

Several restoration paths were identified and IMO system operators were assigned to direct the restoration of each path simultaneously and independently, by building on surviving electrical islands and re-starting generators. The following objectives were initiated (The numbered paths are for naming purposes only and do not indicate restoration priority or sequence.):

- Secure Northwestern Ontario to maintain it as operationally viable and reliable by decreasing the flow into Ontario below protective relaying settings, and increasing generation in Northwestern Ontario;
- Restoration from the Niagara Area;
  - Path 1A-Beck to Bruce, Nanticoke, Burlington
  - Path 1B-Burlington to Pickering
- Restoration from the Cornwall Area; and
  - Path 2-St. Lawrence to Lennox, Darlington, Pickering
- Restoration from the Chats Falls Area.
  - Path 3-Chat Falls re-start to Pickering, East / West parallel

Progress along each of the major restoration paths proceeded independently of each other. Initially, during the first stage of restoration, progress in southern Ontario was impeded by uncertain system conditions in the island that primarily included upstate New York. This delay in turn impacted time limited stored energy systems (such as battery backup systems) in Ontario, which in some cases ran out prematurely causing critical equipment to become unavailable as restoration proceeded. This along with

other factors forced many changes to the restoration paths, or halted restoration altogether in a particular direction.

While maintaining the overall restoration strategy, IMO operators needed to identify changing conditions and continually assess restoration path alternatives. As an example, when it became apparent that the restoration from Saunders GS (Path 2) would be delayed due to equipment difficulties in the path, the IMO halted Chats Falls GS restoration towards Saunders (Chats Falls resources were intended to augment Saunders generation capability). Restoration Path 3 was then initiated from Chats Falls and re-directed to Cherrywood. Coincident with this change, IMO operators re-directed Saunders Path 2 to proceed to Darlington via the Lennox switchyard, utilizing the 500 kV transmission system instead of the 230 kV system to reach Cherrywood.

Ontario's Basic Minimum Power System was re-established at 05:20 EDT August 15, 2003, 13 hours and 9 minutes after the blackout with the paralleling of the Ontario East and West Systems at Wawa. As a result of a lack of information regarding the cause of the blackout and uncertain system conditions, the IMO and Michigan system operators mutually agreed not to re-connect their systems until systems studies engineers could fully assess the situation. This was completed and the Ontario-Michigan interconnection was re-established on August 17, 2003 at 19:46 EDT.

Restoration of the IMO-controlled grid with the exception of the Ontario -Michigan interconnections was completed at 18:26 EDT August 15, 2003 with the re-establishment of the Ontario-Québec St. Lawrence Interconnections, 26 hours and 16 minutes after the blackout.

The restoration of Great Lake Power's (GLP) transmission system was undertaken by GLP operating personnel with the IMO's concurrence. GLP restored their transmission system into three electrical islands awaiting the IMO's direction to synchronize to the rest of the IMO-controlled grid. This was enabled by the independent action of a GLP maintenance crew in isolating a generating station from their transmission system and restarting a generator to supply plant station service before governor pressure had decayed to an unacceptable level.

**B. Effectiveness of Restoration Procedures, Training and Exercises**

**Restoration Rules and Procedures**

The RWG, in its analysis of the system restoration effort, determined the following findings related to Restoration Rules and Procedures:

Restoration of a large interconnected power system from a blackout condition is a complex and methodical undertaking, requiring constant communication and cooperation of every market participant. To be efficient, safe, and timely this

process requires that operators adhere to established rules, procedures and communication protocols and that facilities operate as designed.

The Ontario Power System Restoration Plan provided the strategic framework and flexibility necessary to enable restoration through rapidly changing system conditions. This plan was implemented successfully by competent staff with the required skills, as enhanced by regular training and participation in integrated restoration exercises.

Immediately following the blackout there was an unprecedented volume of calls to the IMO from market participants attempting to report as required by procedures. Particularly during the early stages of the blackout, this volume exceeded the capability of the IMO's communication processes and posed a challenge to all operating staff. Similar problems also occurred with other market participants. During the first approximately 13 hours required to restore the IMO-controlled grid, operating staff participated in thousands of conversations, including many conference calls. Problems with communications and restoration participant problems with loss of remote monitoring and control of facilities magnified the complexity of the process considerably. To overcome the challenges encountered during system restoration, operators had to respond with ingenuity and flexibility. Under these circumstances, Restoration Plan Participants are commended for their perseverance and dedication in achieving the objectives of the restoration process.

Emergency response and operating plans were generally effective throughout the emergency. This emergency required a number of changes to accommodate priority loads such as hospitals, water treatment plants and refineries. During the emergency, special procedures had to be invoked that have rarely been implemented in Ontario, including controlled rotational load shedding, the Government of Ontario's request for 50% consumption reduction, and other operating control actions. Implementing an effective rotation of load shedding was initially challenging since load was still being restored from the blackout. Some loads such as the Toronto Transit Commission (TTC, subway) and water and sewage treatment plants, that were shed according to schedules, subsequently had to be removed from schedules as they were deemed to be critical during the emergency. Processes had to be developed to try to provide advance notification of pending load cuts. In the face of these challenges, transmitters and distributors are to be commended for maintaining the integrity of the controlled rotational load shedding process through rapidly changing system conditions, and as newly identified and changing priority loads were identified. Many industrial and commercial customers responded to the voluntary curtailment request and incurred substantial economic consequences.

### C. Communications

#### Operational Communications



The RWG in its analysis of the system restoration effort determined the following findings related to Operational Communications:

A large volume of telephone calls were required during restoration, between the IMO and Restoration Plan Participants, internally within Restoration Plan Participants and externally between Restoration Plan Participants. The nature of restoration requires that the IMO and the Transmitters, along with Restoration Plan Participants directly connected to the grid, communicate via conference call. Thus any inability of these parties to communicate delayed the process.

Operating communications were complicated by the need to determine the state of the power system without the full assistance of automated monitoring capability in many instances. This occurred due to partial losses of data telecommunications for an extended period of time at some critical facilities. Therefore operators were often forced to compensate by needing to frequently confirm the status of facilities and electrical quantities during the restoration process.

During the initial phases in particular, there were instances where operators could not be contacted and some priority calls were missed or “bumped” due to volume. The process of re-establishing dropped conference calls consumed valuable time, particularly if a critical party could not be reached. Consequently, once a team of participants was established in a conference call there was reluctance to terminate the call. This meant that phones and lines were tied up at both the IMO and the Transmitter’s site(s), and if there was only one operator available at a site, that operator was also tied up. This was more critical at certain operating centers that operated as a hub where multiple restoration paths converged.

Under the circumstances, communication between operators was generally effective considering the volume of calls and difficulties encountered as a result of other issues. In terms of opportunities for improvement, voice telecommunications facilities, in particular call prioritization and conferencing capabilities, need to be reviewed and improved. There were times when established operator-to-operator terminology was not used. Also, in some instances time was wasted during the event answering calls of a non-urgent nature, and distractions not relevant to the action at hand, were not expeditiously dealt with.

### **Media and Public Communications**

The RWG in its analysis of the system restoration effort determined the following findings related to Media and Public Communications:

The magnitude of the blackout created a tremendous demand for timely and relevant information by market participants, stakeholders, media, and the public. Throughout the emergency, the IMO attempted to keep market participants, government and the public up-to-date on restoration developments by issuing communications on an on-going basis. The Crisis Management Support Team (CMST) provided the central coordination to enable this information flow.

During an emergency, the CMST provides a forum for Ontario's electricity industry participants and stakeholders, including government, to co-ordinate emergency management initiatives, information and response during a major electricity emergency. The CMST is activated and operates with a structure and responsibilities as defined in the Ontario Electricity Emergency Plan (OEEP). The IMO chairs the CMST meetings.

Within minutes of the blackout, the IMO's Chief Operating Officer activated the CMST. CMST representatives were notified by the IMO, and the CMST conference bridge was opened at 16:30 EDT, nineteen minutes into the blackout. The CMST conducted 30 meetings beginning at 17:00 EDT on August 14<sup>th</sup> through to 17:30 EDT on Friday, August 22<sup>nd</sup>. Throughout the emergency, CMST information was communicated to CMST members by conference call and the IMO's secure web site. Key public messages were developed during the CMST meetings, and communicated publicly by the IMO through media releases and interviews. The IMO supported the government's emergency communications by providing real-time system status updates and responding to technical questions. Government officials have expressed satisfaction with the information provided through this emergency, and the IMO and the CMST can expect to be relied upon to provide similar or increased levels of support in future. Some market participants indicated that the IMO did not provide enough information related to the "bigger picture", including progress being made at the major restoration milestones. Industry associations, notably the Association of Major Power Consumers of Ontario (AMPCO), the Electricity Distributors Association (EDA) and the Building Owners and Managers Association (BOMA) participated in the CMST process and, respecting confidentiality requirements, were able to communicate information to their own members.

#### **D. Determination of the Extent of the Blackout**

After the collapse of the IMO-controlled grid, the IMO's immediate attention was given to determining the extent of the disturbance and implementing the objectives and priorities of the Ontario Power System Restoration Plan. The IMO-controlled grid was found to consist of five relatively small electrical islands of load and generation:

- an island of approximately 720 MW of Saunders generation carrying 40 MW of Ontario load with the rest supplying New York in an island;
- Beck 1 and 2 generation serving 300 MW of Ontario load and providing 900 MW to New York in an island;

- generation and load in Northwestern Ontario (west of Wawa) which remained attached to the Manitoba and Minnesota systems;
- 30 MW load at Spruce Falls supplied by Smoky Falls generating units; and
- 20 MW of Des Joachims generating units and local load.

#### **E. Synchronization**

The OPSRP contains criteria and guidelines for synchronizing electrical islands. The IMO directs the synchronization of all electrical islands encountered within Ontario. Once power system parameters have been adjusted at the direction of the IMO, synchronizing of electrical islands by Transmitter circuit breaker close enable commands occurs per the supervision of Programmable Synchrocheck Relays (PSR) which are set to respect the stipulated criteria.

Electrical islands are often encountered in northern Ontario owing to a minimum of transmission circuits and frequent severe winter and summer storms. Ontario's experience with PSR supervised synchronizing has been reliable.

Subsequent to the power system collapse of August 14, 2003, Ontario was technically never out of synchronism with New York by virtue of Ontario's Beck and Saunders generating stations with small local load pockets having separated from the rest of the blacked out Ontario grid and remaining in a large electrical island based in upper New York state. During the restoration of portions of southern Ontario from this island, those portions were synchronized to the rest of the Eastern Interconnection when New York synchronized with PJM.

The synchronizing of northern Ontario to northwestern Ontario at Wawa, and the reestablishment of interconnected operations with Michigan were loop parallels with a standing phase angle as opposed to synchronizing actual electrical islands.

#### **F. Emergency Assistance**

Imports were maximized while the inter-ties with Michigan remained opened. On Friday, all transmission, except the Michigan ties were restored by 18:26.

#### **G. Event Milestones**

##### **Restoration from the Niagara Area**

- The first circuits were energized out of the Niagara island at 4:42 PM with a goal of bringing power to the Bruce Nuclear generating units. The three Bruce "B" generating units that were available returned to service between 7:13 PM and 9:13 PM.

- Energizing the circuits towards the Bruce Nuclear complex also allowed the IMO to return potential to the Nanticoke generating station.
- Restoration came next toward the greater Toronto area, Pickering Nuclear Stations, the Lambton Generating Station and TransAlta - Sarnia.
- The transmission system in the area bounded by London in the west and Toronto in the east had to be reinforced quickly to support the reloading of the Bruce generation. To perform this, customers' power was restored in a controlled manner at many locations throughout the transmission corridor.

### **Restoration from the Cornwall Area**

- The period from 4:11 PM to 5:15 PM was used to assess the conditions in the area, stabilize available generation, and secure transmission that was operating near its limits.
- At 5:15 PM the first circuit was energized out from the Cornwall area westward towards Pickering, Darlington and Lennox Generating stations. The Darlington generating unit that was available returned to service at 9:18 PM.
- Generating units from Québec were synchronized to the system at 8:17 PM to add additional stability to the area.
- With the transmission system that was restored across the greater Toronto area from Niagara supplying power to Pickering, a link between the Cornwall area and the greater Toronto area was completed at 10:37 PM, forming a complete loop around Lake Ontario.
- While the transmission system was being restored toward Darlington, another restoration effort from Cornwall towards Ottawa began at 6:40 PM in order to restore critical telecommunications facilities.

### **Restoration from the Chats Falls Area**

- Chats Falls generating station units (northwest of Ottawa) were successfully started from power supplied by Québec at 5:15 PM. Restoration from this area was directed to Pickering in an effort to return power to Pickering in an expedient manner.
- After considerable switching efforts, and with the aid of additional units from Québec, circuits were energized from Chats falls towards Pickering at 8:21 PM.
- Power arrived for Pickering from Niagara and Chats Falls at nearly the same time. Pickering was energized from the Niagara sources at 9:15 PM.
- Chats Falls generation was eventually connected to the remainder of the system early Friday.

### **Northeastern Area**

- Several hydroelectric generators remained spinning but not connected to the island north of Timmins. A number of the generators at various facilities were synchronized together, and, by 7:41 PM, the transmission system was energized south to Timmins.
- When sufficient Timmins area load was restored, the transmission system was energized south to the Sudbury area.

- From Sudbury the transmission system was energized in both an eastward direction, towards the pocket of load along the Ottawa River that survived the initial event, and westward towards Wawa.
- The connection between the northeastern area and southern Ontario was completed at 3:43 AM Friday morning, August 15<sup>th</sup>.
- The connection of northwestern Ontario to the rest of the province was completed at Wawa at 5:20 AM Friday morning, August 15<sup>th</sup>.

### **5.3 Recommendations of the Independent Electricity Market Operator**

Of the findings identified by the IMO RWG, four findings are substantive:

#### **1. Unavailability of Key Facilities**

At several key facilities, backup battery or emergency generator power supplies failed after a period of time, causing loss of critical grid monitoring or control capability at many transmission stations across Ontario. This delayed restoration until staff arrived at the affected facilities to manually operate equipment.

#### **2. Delay in Opening Breakers**

More than 2,000 circuit breakers needed to be opened immediately after the blackout occurred. There were instances where Restoration Plan Participants did not independently open circuit breakers as soon as possible upon loss of grid potential, as required by the OPSRP. This delayed the restoration process while the Restoration Plan Participants were contacted to request or confirm that the breaker was opened, or while the planned restoration of a given path was halted until remote facilities could be staffed.

#### **3. Operational Communications**

Recognizing that literally thousands of individual contacts were required to direct the restoration sequence, there were many instances where more timely or effective communications would have reduced restoration time. Restoration Plan Participants are required to contact the IMO immediately in the event of a contingency, and initially this resulted in a deluge of calls into the IMO's operations centre. Under these conditions, the IMO would have benefited from improved telecommunications capability such as call prioritization and more flexible teleconferencing capability. In addition, some participants could not be contacted by the IMO as they too had difficulty with the frequency and magnitude of the calls they had to manage.

#### **4. Priority Loads and Load Shedding**

Through the restoration process, it became clear that available generation would be inadequate for at least several days, and controlled rotational load shedding would have to be implemented to meet normal demands. Although the load shedding process was

implemented successfully, there were some instances where priority health and safety and environmentally-impactive loads were either not identified as exemptions in the pre-determined load cut schedules, or emerged to become a priority due to the duration of the outage. This necessitated many changes to load-shedding schedules during the period of emergency.

### **Overview of Recommendations**

The recommendations are intended to identify opportunities to improve the ability of Ontario's electricity industry to respond to emergency events, effectively restore the power system, and mitigate the impact on public health and safety. For purposes of clarity to guide their implementation the recommendations below are grouped into subject categories which match the categories of Findings determined by the RWG.

### **Auxiliary Equipment and Tools**

#### **Relevant Findings**

The electricity system in Ontario is large and complex with facilities dispersed across all of Ontario, often in remote areas. There is a significant dependency on remote monitoring and control facilities to implement restoration actions at most sites. In physical terms, all of the following equipment is essential to maintain the necessary functionality:

- 1) SCADA (Supervisory Control and Data Acquisition) master at the controlling centre;
- 2) communications channel to the remote site;
- 3) SCADA slave at the remote site, and
- 4) telephone voice facilities (PSTN) between the IMO, transmitters, and Market Participants.

During a blackout, power has to be supplied to every one of the above components for them to function. Normally this is accomplished by batteries, which can last for only a certain period of time. A few of the most critical facilities are backed-up with stand-by generators. Failure of any of these components can delay restoration by causing a loss of monitoring and control capability. At almost every remote facility, the contingency plan for failure of this equipment is to send qualified staff to the remote location to manually operate the facilities. Unfortunately, when controls are operated locally in this fashion, sometimes other critical facilities also become inoperable, notably synchrocheck equipment used to close breakers to synchronize islands.

During blackout conditions, operators are essentially in a race to re-energize facilities before the batteries and other stored energy systems expire. Following the blackout on August 14th, unstable system frequency conditions caused some delays during the initial phases of restoration, requiring Ontario and a neighboring reliability coordinator to assess and resolve the situation. One of the major equipment difficulties encountered

was loss of SCADA monitoring and control for more than half of Ontario's transmission stations about 89 minutes into the blackout, due to failure of the standby generator at a central control centre. The result was widespread loss of monitoring and control capability at these stations until staff arrived on site. This prolonged and complicated the restoration effort.

Given the complexity and large number of components in the electricity system it is recognized that some equipment failures will occur during a blackout of this magnitude. That said, procedures for routine functional testing and monitoring of critical equipment need to be in place and followed and Restoration Plan Participants need to place a higher priority on this.

### **Recommendations-Auxiliary Equipment and Tools**

The IMO RWG recommends the following actions be taken:

- a) All Restoration Plan Participants are to ensure that backup generation and / or batteries are in-place and tested to support critical components and key facilities per the OPSRP and NPCC Policy A-03;
- b) Ensure adequate redundancy is in place to increase the availability of critical facilities such as voice and data telecommunications and SCADA monitoring and control; and
- c) All market participants should review on-site fuel requirements for stand-by emergency generators, including provision for the possibility of delays in obtaining re-supply.

### **Recommendations-Restoration Rules and Procedures**

The IMO RWG recommends the following actions be taken.

- a) Communicate the IMO RWGs findings to all Market Participants, in order that they may improve their own emergency planning and response capability;
- b) Recognizing that the OPSRP proved to be an effective plan, enhance the OPSRP with additional technical details to facilitate path restoration;
- c) Review and revise processes and procedures related to rotational load shedding and priority loads; specifically, recognition of loads critical to grid restoration and priority loads impactive on public health and safety, notification processes, and load shedding while still in the midst of restoration;
- d) Consult with industries to consider developing emergency load reduction guidelines to mitigate the impact of any future prolonged energy shortfall; and
- e) Although not a factor during the power system collapse of August 14, 2003, complete efforts currently underway to provide additional blackstart capability in Ontario.

### **Relevant Findings-Operations**

During the critical initial phase of restoration, progress was essentially halted for some time because the frequency in the Ontario/New York electrical island was far below standard, and in danger of collapse. While it took some time for operators, both here and in New York, to stabilize conditions, this island was important to the subsequent restoration of Ontario.

In the period immediately following the blackout there were some instances where operators did not follow established procedures. For example, some off-potential breakers were not independently opened as required by the OPSRP to allow restoration to proceed rapidly. In addition, progress was delayed because 24x7 communication coverage was not in place at certain market participant locations that were required to operate breakers connected to the IMO-controlled grid.

In spite of all the challenges imposed by the above as well as the facility problems noted elsewhere, operating staff accomplished the restoration objectives.

### **Recommendations-Operations**

The IMO RWG recommends the following actions be taken:

- a) Reinforce the value of the existing integrated restoration exercise program, and provide additional training in the form of tabletop drills. Emphasize restoration priorities, including those requiring independent action.

### **Recommendations-Communications**

#### **Recommendations-Operational Communications**

The IMO's RWG recommends the following actions be taken:

- a) Improve voice telecommunications facilities and procedures to manage call volumes and priorities; and
- b) Through training, reinforce the authorities and roles of Restoration Plan Participants and operating communications protocols.

### **Recommendations-Media and Public Communications**

The IMO RWG recommends the following actions be taken:

- a) The IMO and key industry participants should enhance their ability during an emergency to communicate the current status and future outlook of electricity system conditions to the public and stakeholders, including local government and emergency response officials.



## **6.0 Restoration of New York**

### **6.1 Introduction**

Shortly after 16:00 EDT on August 14, 2003, a cascading series of transmission and plant contingencies outside the boundaries of NPCC led to major power outages in Ontario, New York and parts of New England as well as the electrical separation of New York, New England and all of the Canadian Maritimes from the remainder of the Eastern Interconnection. At approximately 16:11 EDT, as a result of severe frequency and voltages excursions, many large generating units within the New York Control Area (NYCA) tripped. In addition, the NYCA effectively separated along the Total East interface into western and eastern islands, quickly leading to the loss of nearly all customer load in southeast New York. Within the western island, the 345 kV and 230 kV systems remained largely intact from Niagara to the Utica area and from Niagara down through the southern tier to the Binghamton area. Northern New York remained connected to the Utica area through the 765 kV and one 230 kV circuit as well as to Ontario and Québec via the St. Lawrence/Massena 230 kV and 765 kV ties. The nearly 6,000 megawatts (MW) of load within the island was served primarily by New York's Niagara and St. Lawrence hydro facilities, Ontario's Beck and Saunders generation which separated from the Ontario system and remained isolated onto New York at Niagara and St. Lawrence, respectively. In addition power imported via the Châteauguay-Massena 765kV line from Québec remained in service.

The NYISO Emergency Operations Manual defines the Restoration State as occurring when an area within the NYISO Control Area becomes islanded, or when customer load becomes interrupted. The Manual also details the procedures the NYISO employs for the restoration of the basic minimum power system, as defined by NPCC and providing service to the New York State bulk power system.

Following the guidelines of the NYISO's Restoration Plan (the Plan), the NYISO's restoration actions focused on the following goals:

- Stabilize the remaining NYCA transmission system;
- Extend the stabilized system to blacked-out areas to provide start-up power to generating plants and customer load restoration;
- Extend the stabilized system to energized islanded areas to restore frequency control; and
- Restore normal transmission system operations.

Following these goals, these operations have the highest priority:

- Energize the NYS Power System;
- Synchronize the NYS Power System with the interconnection; and
- Restore off-site power to the nuclear power plants.

The NYISO's restoration actions followed the priorities set in the Plan and did not encounter any significant impediments. These operations are acted on in parallel with equal importance. Power restoration to the upstate New York, Long Island area, and parts of Westchester County and New York City began Thursday evening.

**6.2 System Conditions Before the Event and Start of Restoration**

**A. Pre-Event System Conditions**

On August 13, 2003, the NYISO planned for a typical August day for the 14th. The NYISO prepared its day-ahead plan, which is part of the Day-Ahead Market operation. In the day-ahead plan, resources are committed to meet expected load and reserve requirements for the next day. Developing this plan involves consideration of forecasted system conditions, including load forecast, generation and transmission outages, and neighboring system conditions.

The NYISO uses its Security Constrained Unit Commitment (SCUC) software for operation of the Day-Ahead Market. The SCUC process conducts the next day security analysis and ensures the bulk power system can be operated within security limits for the anticipated system conditions. SCUC ensures that bulk power system operating limits, including those for transmission lines and voltage/stability interface transfer limits, will not be violated under the expected conditions.

On August 13, 2003, the NYISO executed the SCUC process for the Day-Ahead Market. Forecasted load for August 14th was representative of a normal summer day at 28,500 MW, which is about 90% of the forecasted summer peak load. There was an expected capability surplus of approximately 3,000 MW above required load and reserve requirements. The components of this calculation for August 13, 2003 are listed in the following table:

Peak Hour:	Hour Beginning 16:00
Total Generation Available (+):	31,662 MW
Estimated Peak Load (-):	28,500 MW
Derated Generation (-):	554 MW
Required Reserve (-):	1,800 MW
NYISO Desired Net Interchange (+):	1,907 MW
ICAP Exports (+):	277 MW
Excess:	2,992 MW

The required operating reserve is 1,800 MW, one and one-half times the NYCA largest single contingency.

There was one 230 kV transmission outage scheduled for that day, the Linden-Goethals A2253, a 230 kV tie with New Jersey, which was due to a previous fault. In addition, there were other non-bulk power transmission outages (facilities below 230kV).

As August 14, 2003 progressed, normal system operations were maintained in the real-time market by the use of the Security Constrained Dispatch (“SCD”). The SCD process, like the SCUC process for the day-ahead plan, ensures that the bulk power system is operated within security limits for real-time conditions. SCD ensures that bulk power system operating limits, including those for transmission lines, and voltage/stability interface transfer limits, are not violated in real-time operation.

Prior to the events of the blackout, the NYISO experienced no forced transmission facility or generation outages, including no NERC reportable events. All scheduled transmission outages scheduled to be returned to service that day (including outages of non-bulk power systems facilities below 230kV) were returned to service by 15:07.

Interface flows in the state were typical for a summer day and within secure limits. New York was importing close to the maximum from New England and Hydro-Québec, there was no Available Transmission Capacity (ATC) remaining on imports from either for most of the day. However, the scheduling on the ISO-NE interface maintains a transfer reliability margin (TRM) of a few hundred megawatts for contingency purposes.

Throughout the day, bulk power system voltages were normal. All monitored station voltages on the 230 kV, 345 kV and 765 kV stations of the bulk power system were within normal operating limits. Voltage limits are established to insure that the worst criteria contingency does not cause the voltages to go below established post-contingency voltage limits, typically 95 % of nominal.

There were no operator declared Alert States or Major Emergencies until the system disturbance occurred. Operating reserves were maintained through the day, with no reserve activations or reserve pickups called.

Up to the time of the blackout, NYISO system operations were normal and typical of a summer day. Transmission system loadings were within normal transfer limits for thermal, voltage and transient stability, and transmission system voltages were within normal operating limits. All generation was operating within rated capabilities for both real and reactive power; all automatic voltage regulators were in service. Transmission and generation operating margins were within applicable limits. The NYISO was in compliance with all NERC, NPCC, New York State Reliability Council (NYSRC), and NYISO Tariff, Criteria, Rules and Procedures.

## **B. The Blackout and the Impact on New York**

At about 16:09, the NYISO control center noted a power swing of approximately 700 MW out to Ontario. At that same time, the operators also observed a coincident swing of similar proportion from PJM into the NYISO. This event appeared to be consistent with the expected system response to the loss of a large generator on the Ontario system. The NYISO Shift Supervisor, therefore, prepared to initiate the NPCC shared

activation of reserve procedure, expecting a call from the IMO reporting the generation loss and the amount of shared reserve that IMO would request from the NYISO.

The power flow of 700 MW entering the NYISO system from PJM and moving westward on the NYISO 345 kV system caused the 345 kV system voltages to rise, with the New Scotland and Edic station voltages approaching their respective normal high voltage limits. Also responding to the increasing voltage, the Marcy Automatic Shunt Switching scheme switched in the 200 MVAR shunt reactor in the 765 kV station. Responding to this voltage rise, the NYISO System Operator contacted the Niagara Mohawk System Operator to prepare to switch out a shunt capacitor, a normal response for this condition.

At approximately 16:11 EDT, as a result of severe frequency and voltages excursions, many large generating units within the New York Control Area (NYCA) tripped. In addition, the NYCA effectively separated along the Total East interface into western and eastern islands, quickly leading to the loss of nearly all customer load in southeast New York. Within the western island, the 345 kV and 230 kV systems remained largely intact from Niagara to the Utica area and from Niagara down through the southern tier to the Binghamton area. Northern New York remained connected to the Utica area through the 765 kV and one 230 kV circuit as well as to Ontario and Québec via the St. Lawrence/Massena 230 kV and 765 kV ties. The nearly 6,000 megawatts (MW) of load within the island was served primarily by New York's Niagara and St. Lawrence hydro facilities, Ontario's Beck and Saunders generation which separated from the Ontario system and remained isolated onto New York at Niagara and St. Lawrence, respectively. In addition, power imported via the Châteauguay-Massena 765kV line from Québec remained in service.

### **6.3 System Restoration**

#### **A. Stabilization of the Remaining Islands**

The NYCA transmission system was islanded with radial interconnections on the Ontario ties at Niagara and St. Lawrence and the Québec tie into Massena. Radial load also remained on the ties out of Waldwick station into the PJM System. The outer boundary of the New York bulk power transmission system that remained in service included Niagara station in the West, St. Lawrence/Massena station to the North, New Scotland station in the Capital area, Ramapo station in the Hudson Valley, and Oakdale station in the Central LBMP zone. These locations along with associated transmission accounted for approximately 60 % of the basic minimum power system that remained intact.

At 17:00, the existing island remained relatively stable and was able to serve about 5,700 MW of load in the western, central and eastern regions of upstate New York. Hydro generation at Beck, Niagara, Saunders and St. Lawrence, some thermal generation in western New York, and the HVdc intertie with Québec formed the basis

for restoration of both the New York and Ontario systems. In addition, the NYISO was importing slightly over 2,400 MW and serving 700 MW of load in northern New Jersey.

### **Load Shedding Events**

There were large frequency and voltage deviations during the islanded period as generation and load imbalances were encountered. Throughout this event, load and generation balance was essential. The NYISO operators instructed all TOs to notify the NYISO of all load restorations and generator availability. TOs were instructed to match load with generation as it became available. Also to be considered in this balance is voltage control. In some cases, load was restored from generation, in other parts of the NYCA load was restored to control high voltages due to line restoration. This process of coordination was very successful due to the repeated training in communications between the NYISO and the Transmission Owner operators.

Three instances of load shed actions are discussed below. Additional load shedding may have been required at other times at the local areas.

### **Niagara Mohawk**

At 18:01 on August 14, the NYISO Operator directed Niagara Mohawk to shed 300 MW of load west of Edic for frequency control. As some load was being restored at that time in the NYCA Island generation was not yet available, frequency was declining slowly. The 300 MW of load shed by Niagara Mohawk allowed the system to reestablish an acceptable frequency at that time.

### **NYPA**

On August 14<sup>th</sup> between 17:05 and 19:00, corrective actions were directed by NYPA ECC operators to better balance load and generation and to stabilize voltages in the St. Lawrence (North Country) area. These actions included several 100 MW step adjustments (up and down) to the import from Hydro-Québec over the MSC-7040 765 kV line; rotational load shedding of the three 60 MW Alcoa West (formerly Reynolds Aluminum) processing lines; the opening of the two Cedars 115 kV lines at Dennison Rd. to alleviate approximately 100 MW of Ontario load being served from New York (this load was shed and at about one hour later was again served but via a radial 115kV feeder from the Cedars (HQ) area) and the switching of 765 kV reactor banks at Massena. As a result of these actions, no additional residential or commercial customer load had to be shed in the North Country during the course of that evening.

### **NYISO**

By 06:00 on August 15<sup>th</sup>, 56% of the load had been restored in the NYCA. At 7:35 the NYISO activated EDRP/SCR programs for hours 10:00 to 24:00. The NYISO also requested voluntary public curtailment of electric use and announced temporary NYSDEC waivers of air emissions limitations. The NYISO was preparing for the

morning load to begin picking up. At 08:00, as part of a conference call with the Transmission Owners, they were notified that load shedding might be required due to the morning load pickup. The group agreed that load shed allocation process would be modified and that the load shed allocations would be calculated based on the percentage of the current TO load to the total NYCA load at that time.

At 09:33, the NYISO requested 300 MW of load shed, distributed among the Transmission Owners. The load shed was called due to the NYISO area control error dragging in excess of 500 mw for more than 10 minutes as defined in NYISO Emergency Operations Manual. This condition was being monitored throughout the morning. The load shed effectively restored the area control error to acceptable levels.

#### **B. Effectiveness of Restoration Procedures, Training and Exercises**

Electric power system restoration in New York takes place at two levels: the restoration of the backbone basic minimum power system coordinated by the NYISO, and the local area restoration coordinated by the TOs. Successful restoration is a knowledge-based collaboration between the NYISO, the TOs, and all the major generating operators in the state. Training provides the basis for that knowledge-based collaboration that worked well during this event.

Effective Restoration Plans and extensive prior training allowed the NYISO to restore power to the NYCA completely in less than 30 hours. Following separation from the Eastern Interconnection, New York's bulk power system performed well, and the NYISO therefore was able to follow the principles of the Restoration Plan. In accordance with the Restoration Plan, assessment and restoration of the bulk power system began immediately following the system disturbance. The NYISO focused its preliminary efforts on stabilizing frequency in the NYCA in order to synchronize the New York island to the Eastern interconnection, and extending the remaining transmission system to start up generation and restore customer load.

The NYISO's control room dispatchers coordinated these efforts effectively with Transmission Owners and Generators through the TO's in the NYCA and with control room dispatchers in neighboring control areas. Transmission System Operators and Generator Operators made extraordinary efforts to bring transmission facilities and generating units back into service. In several cases, generator operators intervened to ensure the quick restart of generation by making the decision to trip certain units. NYISO Operations personnel remarked on the outstanding cooperation among the Demand Response Providers and the various control areas and noted that this cooperation was vital to efficient system restoration.

The NYISO conducts training seminars for NYISO/TO system operators every spring and fall. This training includes topics such as voltage control, communications, System Restoration Plan, and other topics relating to system operation. Each spring the program addresses system restoration through a review of the basic principles involved,

a detailed review of the NYISO backbone restoration plan, a summary review of each TO's restoration plan, and concludes with a tabletop exercise. The exercise allows the operators to step through and simulate a system restoration following a complete system shut down. Subsequent to the joint training session, a one day restoration drill is conducted with NYISO and TO operators stepping through the restoration process in a telephone exercise from their home control centers.

### **C. Communications**

The NYISO maintained multiple levels of communications throughout the event. Immediately following the initial disturbance, system operators contacted the TO to determine the condition of their systems. At a second level, NYISO Manager/Supervisor staff established contacts with staff at the TOs to plan a course of action to be carried out by the system operators. On a third level, NYISO Manager/Supervisor staff setup contacts with the neighboring control areas for communicating current system status and coordinating next steps.

The internal NYISO operating procedures follow and complement NPCC Documents C-03 and C-20, which establish protocols among the NYISO, transmission owners, market participants, and neighboring control areas for normal and emergency conditions.

#### **Transmission Operator Communications**

Throughout the event, the NYISO was in constant communications with the TOs through the control center system operators (dispatchers). In addition, the NYISO established secondary lines of communications with the TOs to identify and agree upon the next steps to be carried out by the system operators. Initial conversations included the sharing of information on the status of each TO's area and the expected restoration procedures. The TOs and the NYISO also conferred to set up the actions needed in anticipation for re-synchronization. All restoration activities, including those required for synchronization, were carried out through coordinated steps controlled by the control center system operators. Likewise, the NYISO was in constant communications with the neighboring Control Areas principally through the control center system operators.

#### **NERC/NPCC Calls**

At 17:23, the NYISO began regular contact with the NERC conference calls scheduled throughout the period. The NYISO reported the current status of the system and the progress of the NYCA restoration.

Also during the evening of August 14, NPCC began to schedule regular conference calls. These calls put the five control areas in contact for system updates on a regular basis. These calls provided an alternate means from the system operator contacts to share information and to request assistance as needed.

## **Generator Communications**

The NYISO Customer Relations Department, in conjunction with the Market Monitoring Unit, established a process for collecting generator status. Beginning the evening of August 14th and continuing periodically throughout the restoration period, NYISO staff called generators to determine their physical condition and estimated time the unit would return to service. The focus was on large capacity units and downstate units. NYISO Operations Department confirmed this information with the New York TOs and used it to prepare for next steps in the restoration.

### **D. Determination of the Extent of the Blackout**

As the afternoon of August 14<sup>th</sup> progressed, the operators in NY noted a power flow of 700 MW, entering the NYISO system from PJM and moving westward on the NYISO 345 kV system, which caused the 345 kV system voltages to rise, with the New Scotland and Edic station voltages approaching their respective normal high voltage limits. Also responding to the increasing voltage, the Marcy Automatic Shunt Switching scheme switched in the 200 MVAR shunt reactor in the 765 kV station. Responding to this voltage rise, the NYISO System Operator contacted the Niagara Mohawk System Operator to prepare to switch out a shunt capacitor, a normal response for this condition.

At approximately 16:11 EDT, the NYISO system operators witnessed multiple line and generator trips in an approximate two minute window. Alarm displays activated noting a major event had occurred on the system. The NYISO shift supervisor took actions to assess the condition of the grid. Through telemetry available to him at the NYISO and telephone communications with transmission owners, the Shift Supervisor was able to determine the extent of the outages in New York and to take decisive actions necessary to begin restoration effort.

As a result of severe frequency and voltages excursions, many large generating units within the New York Control Area (NYCA) tripped. In addition, the NYCA effectively separated along the Total East interface into western and eastern islands, quickly leading to the loss of nearly all customer load in southeast New York.

Within the western island, the 345 kV and 230 kV systems remained largely intact from Niagara to the Utica area and from Niagara down through the southern tier to the Binghamton area. Northern New York remained connected to the Utica area through the 765 kV and one 230 kV circuit as well as to Ontario and Québec via the St. Lawrence/Massena 230 kV and 765 kV ties. The nearly 6,000 megawatts (MW) of load within the island was served primarily by New York's Niagara and St. Lawrence hydro facilities, Ontario's Beck and Saunders generation which separated from the Ontario system and remained isolated onto New York at Niagara and St. Lawrence, respectively. In addition, power imported via the Châteauguay-Massena 765kV line from Québec remained in service.



## **E. Synchronization**

### **PJM Synchronization:**

One of the NYISO's first objectives was to resynchronize the NYCA transmission system with the PJM 500 kV interconnection at Ramapo, to restore normal frequency control to the Western New York island. The effort to achieve synchronization was complicated by the islanded NYISO operation. While the NYISO was islanded, there were two primary areas of concern, 1) maintain frequency control that requires the balance of the island load and generation resources and 2) voltage control on the bulk power system.

The first was the frequency control that requires the balance of the island load and generation resources. Restoration of large amounts of load without sufficient generation would cause the frequency to decay and result in the available generation tripping off-line. For the New York island, this was compounded by the fact that additional generation from the IMO (Beck and Saunders) was connected and additional load in Northern New Jersey was being served by the island. The second area of concern was voltage control on the bulk power system. High voltages can result from interconnecting transmission lines without loads at the end of these lines. Thus when a transmission line is energized, there needs to be some load at the end of the line to control the voltage. But for the large amounts of load to be picked up to control the voltage and quickly restore the grid, there must be generation or an interconnection to address the frequency control concern. To allow the NYISO restoration to proceed most efficiently, the need to synchronize the New York island to the Eastern Interconnection via the PJM 500 kV interconnection was given the highest priority, to stabilize the frequency.

Synchronization of two systems -- the Western New York island and the Eastern Interconnection (PJM's grid) -- required that the two systems be operating at nearly the same frequency. Synchronization to the PJM grid was initially discussed at 17:18 and an attempt to synchronize was unsuccessful at 18:02 due to large frequency imbalance between the islanded NYISO and the PJM systems. Following that initial attempt, the NYISO, NYPA, Con Edison, and Orange & Rockland adjusted the New York system load generation configuration during the next hour. At 18:52, a synchro-check relay saw the two systems close enough to close in at S. Ripley. Unaware of this synchronization, the NYISO directed Con Edison personnel to manually close into the PJM 500 kV grid via synchroscope operation at Ramapo station at 19:06. Ultimately the tie at Ramapo, which was restored at 19:08, was the second tie with the Eastern Interconnection, providing a more secure interconnection with the 500 kV and 345 kV transmission systems at PJM. Following these events the frequency control in the Western New York Island returned to near normal.

### **ISO-NE Synchronization:**

In preparation for synchronizing with ISO-NE, efforts were made to stabilize voltages in the eastern area of New York. Following the successful reclosing at Ramapo, system frequency in the NYCA had stabilized. At that point the effort was to strengthen the NYCA to provide a more stable voltage platform for ISO-NE to tie into. This was accomplished while restoring lines into the Con Edison area at Sprainbrook. With the path from Ramapo to Sprainbrook restored, a parallel effort was made to restore transmission to Sprainbrook from New Scotland. This step effectively stabilized voltage allowing additional load to be restored and provided a solid platform for ISO-NE to synchronize.

The restoration path was extended from New Scotland to the ISO-NE Northfield Station. The NYISO Operator, along with the ISO-NE Operators coordinated the actions required with their associated Transmission Owners. ISO-NE utilized a pumped storage hydro facility there to synchronize with the NYCA through the use of the synchroscope at Northfield. The actions were successfully completed at 01:53 on August 15th.

#### **G. Emergency Assistance**

The coordination and cooperation within the NYCA and among its neighbors was excellent. During the initial hours of the restoration, NYISO was relying, in part, on generation in Ontario to continue to serve load that remain in service. The NY tie with Hydro-Québec remained in service providing additional energy to the New York Grid. As the NYISO began to establish its ties with PJM and ISO-NE power flows were maintained into NY to assist in the restoration process in NY. This energy provided additional resources to allow NY to continue to restore customers load to the system.

At 12:26 on August 15, 2003 the ISO-NE notified the NYISO that ISO-NE was ready to put the CSC in service at 100 MW to Long Island. The Cross Sound Cable (CSC) is a new HVdc tie between Long Island and Connecticut. As a result of the blackout, the U.S. Secretary of Energy declared that an emergency existed and both the NYISO and ISO-NE were directed to operate the HVdc line for purposes of reliability during the emergency.

#### **G. Event Milestones**

The following is a summary of events that occurred during the restoration process in New York:

##### **August 14, 2003**

- At 16:27, the NYISO ordered Gilboa to begin its Black Start procedures. Unit blackstart procedures were completed successfully. Synchronization to the backbone was delayed due to the inability to close in on the Gilboa – Fraser 345 kV line. It was determined that this line could not be closed at Gilboa due to the large voltage disparity between Gilboa and Fraser. System voltages were further

stabilized when the Marcy-New Scotland 345kV line was restored at 1905. Subsequently, the Gilboa-New Scotland, Fraser-Gilboa and Gilboa-Leeds 345 kV lines were all restored within the next 15 minutes.

- At 16:45, NYISO contacted LIPA to inquire about system status. LIPA reported that it had completely separated and planned to bring on gas turbines to begin restoration procedures as soon as possible.
- At 17:00, the existing island remained relatively stable and was able to serve about 5,700 MW of load in the western, central and eastern regions of upstate New York. Hydro generation at Beck, Niagara, Saunders and St. Lawrence, some thermal generation in western New York, and the HVdc intertie with Québec formed the basis for restoration of both the New York and Ontario systems. In addition, the NYISO was importing slightly over 2,400 MW and serving 700 MW of load in northern New Jersey.
- At 17:15 over the Hotline, the NYISO reported to the TOs the status of the bulk power system, and directed them to follow through with their local restoration plans and to coordinate anything affecting the bulk power system with the NYISO.
- At 18:01, as the NYISO undertook efforts to maintain frequency, conditions warranted a load shed request to Niagara Mohawk who was ordered to shed 300 MW of load west of Edic for frequency control.
- At 18:02, an attempt to synchronize at Ramapo was unsuccessful due to large frequency imbalance between the islanded NYISO and Eastern Interconnection through the PJM system. For the next hour, the NYISO, NYPA, Con Edison, and Orange & Rockland took steps to coordinate the New York system load configuration and generation in an effort to make a second reclosing attempt.
- At 18:52, the first synchronization to PJM took place at South Ripley when an auto synch-check relay allowed a reclosing scheme to continue a reclose attempt on the 68 and 69 lines synchronizing Erie East (PJM) – South Ripley-Dunkirk 230 kV tie at South Ripley. As the NYPA, Con Edison and Orange and Rockland worked to get the NYCA closer to Eastern Interconnection, the auto synch-check relay at South Ripley saw the systems close enough to reclose.
- At 19:06, the NYISO directed Con Edison personnel to manually close into the PJM 500 kV grid via synchroscope operation at Ramapo station. The re-closing at Ramapo was also successful, providing a stronger 500 kV tie to the Eastern Interconnection, adding to the existing 230 kV tie.
- At 19:56, a Southeast transmission corridor from Buchanan to Eastview and from Eastview to Sprainbrook was energized to Sprainbrook station. Load was restored for voltage control. Transmission was then extended into Queens.
- By 21:50, the energized transmission grid was extended along the Northeast corridor from New Scotland 345 kV into Westchester through the Leeds, Pleasant Valley, Wood Street, Millwood, and Eastview 345 kV substations.
- At 23:00, Con Edison working in parallel with the NYISO efforts extended the energized PJM grid from PJM (Hudson 230 kV) into the Con Edison system through Farragut, Gowanus, and Goethals to the East Coast Power Linden generating station. At 23:30 the East Coast Power Linden generating station black started its facility and synchronized to the energized Goethals substation

bus. This created a southern system synchronized with the Eastern Interconnection. Con Edison developed a plan to parallel the northern and southern systems via the sub-transmission system but this could not be accomplished due to load restoration restrictions.

### August 15, 2003

- At 00:00 on August 15th approximately 40% of the load had been restored to the NYISO system. The NYISO and PJM continued to restore the remainder of the tie lines between the two control areas.
- At 00:08 on August 15th, the Northeast corridor feeders and the Southeast corridor feeders into Sprainbrook were then paralleled at Con Edison's Sprainbrook substation, thereby providing two upstate New York transmission paths to the Westchester County area, with the system now tied to the Eastern Interconnection at Ramapo 500 kV station.
- At 01:53 EDT on Friday, August 15, The transmission grid was extended from the New Scotland 345 kV substation into ISO-NE by an express feeder through Alps and Berkshire into ISO-NE's Northfield substation. NYISO and ISO-NE coordinated the synchronization of the New England transmission system to the NYCA transmission system, via synchroscope operation at Northfield. This restored normal frequency control for ISO-NE. Synchronization of the New England transmission system to the NYISO's transmission system was required to be sequenced after the Southeast and Northeast corridor feeders were paralleled at Con Edison's Sprainbrook substation. This sequencing was required due to the high voltage conditions observed at the New Scotland 345 kV substation with the Northeast express feeder into NYC energized but not paralleled at Sprainbrook until 00:08.
- At 04:00 on August 15th, approximately 60% of the NYCA load had been restored. At 04:08 Con Edison energized the Sprainbrook-West 49th Street and the West 49th Street to 13th Street 345kV circuits and began adding load to control the voltage conditions.
- As the NYISO was restoring transmission, generation and load to the larger portion of the NYCA, LIPA was restoring load and generation to multiple pockets in their area. Four islands of several hundred megawatts each were formed. These electrical islands were then synchronized to form a contiguous system on Long Island. The ability of the Generation Operators to manually control their units, both Steam and Gas Turbines, to exact megawatt output level requests allowed for steady and continuous growth of the islanded systems.
- At 05:12 the energized transmission grid was extended from the Con Edison system (Sprainbrook 345 kV) into Long Island (East Garden City 345 kV). Synchronization of the Long Island transmission system to the NYISO's transmission system restored normal frequency control for Long Island.
- At 06:29 on August 15<sup>th</sup>, the southern system was then paralleled to the northern system at Farragut Substation utilizing a second supply from Hudson and phase angle regulator tap moves to adjust the phase angle.

- At 07:34, the NYISO issued an order implementing its Emergency Demand Response Program (EDRP) and its Special Case Resources (SCR) program, which would reduce load beginning at 10:00 and continue until 24:00. The NYSDEC Air Emissions waiver was in effect and would allow generators to go to maximum capability if required. This remained in effect until the end of the Major Emergency at 24:00 on August 17th.
- At 08:00 approximately 64% of NYCA load had been restored; however, the morning load pickup was increasing faster than the generation was coming on line. At 08:59, the NYISO made a hotline call to request immediate relief from the EDRP/SCR customers.
- At 09:25, the NYISO informed the TOs of the potential for rolling blackouts due to the load and generation imbalance. At 09:33, the NYISO ordered the TOs to shed 300 MW of load due to the Area Control Error (ACE) dragging 630 MW.
- At 10:02, the NYISO informed the TOs to restore half the load that was shed in response to the NYISO's direction. At 10:24, the NYISO instructed the TOs to restore the remainder of the load.
- At 12:26, the Cross Sound Cable went in service, allowing an additional 100 MW of emergency energy to flow from ISO-NE to Long Island.
- By 22:30 on August 15th, all Transmission Owners notified the NYISO that 100% of their customers were on line; at that point, service across the NYCA was completely restored.

The NYISO remained in the Major Emergency State for the remainder of the weekend to ensure that the bulk power system was stable and the NYISO was capable of supplying load, and to ensure an orderly reopening of the energy/ancillary service markets.

#### **6.4 Recommendations of the New York ISO**

Dedicated System Operators, effective Restoration Plans and extensive prior training allowed the NYISO to restore power to the NYCA completely in less than 30 hours. Following separation from the Eastern Interconnection, New York's bulk power system performed well, and the NYISO therefore was able to follow the principles of the Restoration Plan. In accordance with the Restoration Plan, assessment and restoration of the bulk power system began immediately following the system disturbance. The NYISO focused its preliminary efforts on stabilizing frequency in the NYCA in order to synchronize the New York island to the Eastern interconnection, and extending the remaining transmission system to start up generation and restore customer load.

The NYISO's control room dispatchers made extraordinary efforts to coordinate with Transmission Owners and Generators through the TO's in the NYCA and with control room dispatchers in neighboring control areas. Transmission System Operators and Generator Operators worked effectively to bring transmission facilities and generating units back into service. NYISO Operations personnel remarked on the outstanding cooperation among the Demand Response Providers and the various control areas and noted that this cooperation was vital to efficient system restoration.

As a result of this review by the NYISO and Market Participant working groups, including transmission owners, several areas have been identified that may warrant an effort toward modifying or enhancing the NYISO Emergency Operations Manual. In particular, the NYISO will be looking into the following areas:

- 6.4.1** Review the distribution of responsibility for restoring the bulk power system between the NYISO and individual Transmission Owners (TOs). Also, a preliminary assessment needs to be made regarding the amount of capacity that should be reserved to energize the system and major generation sites in the New York Control Area in the event of a major system disturbance.
- 6.4.2** Develop a method for TO System Operators, Generator Operators, and neighboring Control Area System operators to interactively, remotely, participate in restoration tabletop exercises.
- 6.4.3** Improve communications with all parties affected, including TOs and neighboring control areas. It was agreed that additional communication was needed to better disseminate information concerning the state of the control area and the control areas around the NYCA.
- 6.4.4** Review and evaluate specific personnel roles, responsibilities, and staffing requirements at each control center for a set period following an event of this type.
- 6.4.5** Establish a “command post” location at each control center to be dedicated for events similar to this that require phone centers and map boards for non-dispatch staff to coordinate activities off the dispatch floor.
- 6.4.6** Investigate the extension of TO and NYISO EMS/SCADA points on critical tie-lines allowing the operators to look several busses into the neighboring control area TO networks.
- 6.4.7** Investigate relay practices on control area ties, specifically reclosing schemes and the impact on restoration events.

## **7.0 Restoration of New England**

### **7.1 Introduction**

On Thursday, August 14, 2003, a severe and widespread disruption of the bulk power grid in the north central and northeast areas of North America occurred. Due to severe transients, nearly the entire New England power system, plus all of the Maritimes power system split away from the Eastern Interconnection and remained separated for almost ten hours. Roughly 3,100 MW of Maritimes and New England generation tripped during the event. An offsetting amount of roughly 3,100 MW of demand was also interrupted, limiting the frequency peak within the New England/Maritimes electrical island to approximately 60.35 hertz immediately after island formation. Most of the interrupted load was in the area of southwest Connecticut that remained connected to New York for roughly 56 seconds before a large generation deficiency and low voltage resulted in its separation and collapse.

Within the New England/Maritimes electrical island, generators were subjected to severe frequency, power and voltage transients. Automatic voltage regulators, frequency modulation on HVdc facilities and Power System Stabilizers on select generators worked to dampen a 1/3 hertz oscillation. In the longer term, continued HVdc frequency modulation, most generator governors and Operator action worked to adjust and steady frequency. Operators also took action to secure and maintain operations in the New England/Maritimes island, including timely manual load shedding and adjustments to techniques for real-time generation dispatch, frequency control and scheduling.

Intelligence was quickly gathered to define the state of the New England power system and Operators began efforts to restore the system. Most of 140 MW of load lost in northern Vermont was quickly restored with the remainder being restored within an hour. Roughly 500 MW of load, manually shed in Connecticut and western Massachusetts to stabilize system conditions, was restored by 19:30 hours. By 23:45 hours, essentially all of the southwest Connecticut area transmission was restored. The planned re-synchronization of the New England/Maritimes island to New York and thus the Eastern Interconnection occurred at 01:53 hours on Friday, August 15, 2003. After synchronization, additional New England – New York tie lines were restored and New England supplied up to 600 MW of Emergency power to New York on these ties. Also, as facilitated by a DOE Emergency Order issued in response to the blackout, New England began delivering up to 300 MW of Emergency power to Long Island via the non-commercial Cross Sound Cable HVdc facility. Emergency power sales began on Friday, August 15 and continued through the weekend and peaked at 1,500 MW on August 16, 2003.

### **7.2 System Conditions Before the Event and Start of Restoration**

**A. Pre-Event System Conditions**

Prior to the system disruption on August 14th, operating conditions within the New England and Maritimes power systems were normal. Real and reactive generation reserves were adequate, generator and transmission station voltages were within normal limits, except for one generator station where voltage was 1 to 2 kV high. Transmission interface loadings were within limits that ensure both first contingency coverage and an ability to restore coverage for a second contingency within thirty minutes.

<b>Conditions on the New England System-4:00 PM</b>			
Temperature in Boston:	87° F	Dew Point in Boston:	65° F
Temperature in Hartford:	90° F	Dew Point in Hartford:	67° F
Daily peak load for New England:	23,347 MW		

The four Satellites supplied the 4:00 PM, 23,347 MW load as follows:

<b>Satellite Load-4:00 PM</b>	
<b>CONVEX</b>	7,944 MW
<b>Maine</b>	1,394 MW
<b>New Hampshire</b>	1,731 MW
<b>REMVEC</b>	12,278 MW
<b>NEPOOL</b>	23,347 MW

Inter-Area Scheduled and Actual Interchange for the hour ending 4:00 PM are shown in the following table. Note that a negative sign indicates a power transfer import into the New England Area.

<b>Inter-Area Schedules and Actual Interchange Hour Ending 4:00 PM</b>		
	<b>Actual</b>	<b>Scheduled</b>
<b>NEPOOL</b>	-1,792 MW	-1,722 MW
<b>NYISO</b>	376 MW	380 MW
<b>NBEP</b>	-511 MW	-450 MW
<b>HQ</b>	-1,657 MW	-1,652 MW

All schedules were being adhered to using normal control performance criteria; no unusual conditions occurred leading up to the event.



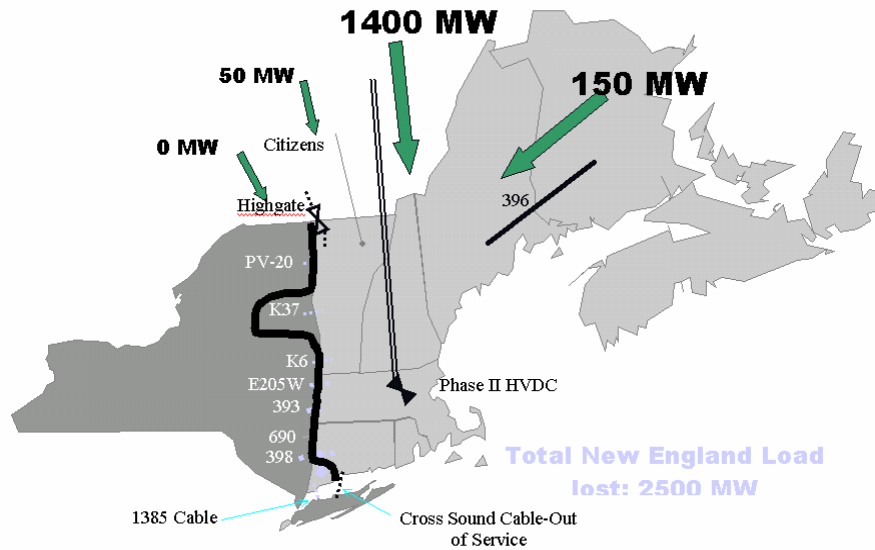
## **B. The Blackout and the Impact on New England**

On August 14, 2003, beginning at about 12:05 PM and continuing up to about 4:10 PM Eastern Daylight Time, a series of generator and transmission outages occurred affecting the Eastern Interconnection's ability to serve load in the northern Ohio area, roughly between Toledo and Cleveland. What began as separate independent events ultimately evolved into cascading thermal overloads followed by voltage collapse.

Towards the end of this period, the systems were stressed beyond their stability limits; power angles jumped in New York, power surged into the radial New England and Maritimes systems, and frequency rose to 60.3 hertz. This triggered the action of a special protection system (SPS) in New Brunswick to reject roughly 380 MW of generation. At 4:10:45 PM, frequency took a rapid and substantial drop, ultimately reaching its lowest value during the disturbance (59.5 hertz measured in New Brunswick at roughly 4:10:46 PM). Simultaneous with this frequency drop, power surged from New England towards New York, and circuits on or close to the New England – New York border experienced very low voltages. At about 4:10:47 PM, protection relays at Northfield appropriately interpreted the power surge and accompanying voltage drop as a fault, caused circuit breakers to open the Northfield end of the tie line, and sent transfer trip signals to the Berkshire and Alps ends of this three terminal line.

Similar transient conditions and appropriate circuit trips occurred on other New England – New York tie lines or lines close to the New England – New York border. A slight back-up of the split into Connecticut left a portion of southwest Connecticut (later referred to as the Long Mountain/Norwalk area) tied to New York via two circuits, but after roughly 56 seconds these circuits had opened and the area collapsed.

The following diagram geographically displays where the New England/Maritimes split from New York.



**Figure 1 New England/ Maritimes Island**

### 7.3 System Restoration

#### A. Stabilization of the Remaining Islands

##### Manual Load Shedding

Connecticut in general, and southwest Connecticut in particular, are congested load pockets within New England. Transmission interfaces are limited by voltage performance, and therefore reactive dispatch is critical to maintaining reliability. Reactive requirements are predominantly supplied by static devices, such as capacitors, with dynamic reactive reserves maintained on generators for contingency response. The August 14 disturbance separated a significant amount of load in southwest Connecticut from the New England system. The separated area eventually blacked out. The transients experienced during the system separation caused extremely low voltages throughout Connecticut, thus automatically disconnecting a substantial amount of customer load due to the low voltage. In addition, most Connecticut generators tripped, with the Millstone nuclear units 2 and 3 being notable exceptions.

Immediately following the separation, the Connecticut transmission voltage reached high levels: more than 385 kV on the 345 kV system, and 130 kV on the 115 kV systems.

This was a result of several factors: the static capacitors remaining temporarily in service; load loss; reduced reactive losses on transmission circuits; and loss of generation to regulate the system voltage. The Millstone units changed from full reactive output (lagging) during the separation transient, to absorbing VARs (leading) after the separation. Overvoltage protective relays operated, tripping both transmission

and distribution capacitors across the Connecticut system. In addition, the load in the part of Connecticut still energized began to increase during the first 7 to 10 minutes following the event. This increase was most likely due to customers restoring load which had tripped during the transient. The load increase, combined with the capacitors tripping, resulted in transmission voltages dropping from high to low voltages within 5 minutes. The voltage on the 115 kV system fell to approximately 100 kV to 105 kV.

Simultaneous with the voltage transients, thermal overloads were experienced on the Connecticut and western Massachusetts transmission systems – these resulted from the generation losses in Connecticut and western Massachusetts during the system separation. ISO-NE ordered all fast start generation by 4:16 PM. But before the generation could come on-line, increased load aggravated the thermal overloads. The most severely overloaded lines were the Manchester-Hopewell 115 kV line in the Middletown transmission area, and the Breckwood 115 kV transmission cables in western Massachusetts. These lines were operating over their Long Time Emergency (LTE) ratings.

Furthermore, the local Satellite Control Center covering the state of Connecticut and most of western Massachusetts, the **CON**necticut **V**alley **EX**change (CONVEX), was informed by Middletown Station and West Springfield that the voltage was too low for generation to synchronize. Faced with the thermal overloads and critically declining voltages, CONVEX ordered manual load shedding. This was completed by 4:40 PM. The load shedding was implemented through SCADA controls from CONVEX and the United Illuminating Dispatch Center. Selectable load shedding occurred in the Springfield and Berkshire area of western Massachusetts, and in central and southwest Connecticut. The load shedding restored the voltage and allowed generation to synchronize. It also reduced thermal overloads to below LTE limits. A total of about 500 MW of load was shed: 400 MW in Connecticut and 100 MW in western Massachusetts. This action taken by the CONVEX System Operators was timely and decisive, stabilized the system in Connecticut and western Massachusetts, and was crucial in preventing further disruption of the New England/Maritimes island.

### **Frequency Control and Generation Dispatch within the Island**

After island formation, erratic frequency behavior ensued. At ISO-NE, Operators acted to change generation dispatch and scheduling methods to reduce frequency excursions. Actions included a changeover from automatic to manual dispatch orders and appropriate opting for flat frequency or tie line bias control depending on the status of tie lines.

The last approved Unit Dispatch Solution (UDS) case was at 16:02, and the Desired Dispatch Points (DDPs) received represented the generation requirements applicable prior to islanding. As a result, Operators manually dispatched generation after the separation due to instability of the State Estimator, on which UDS is dependent for estimating current generation values and other information.

Automatic Generation Control (AGC) paused at 16:10:54 and suspended at 16:11:10 due to tie line telemetry problems. At 16:51:34, AGC was manually cleared of the suspended state, and the control mode was changed from tie-line bias to flat frequency. The Maritimes Control Area also changed from the tie line bias control mode to the flat frequency mode at 16:20:35 and back to tie line bias at 18:34:18.

### **B. Effectiveness of Restoration Procedures, Training and Exercises**

The overall system restoration in New England was timely and successful. Restoration plans/procedures proved to be effective roadmaps for responding to the system disruption that occurred on August 14, 2003. The restoration plans/procedures were developed by the New England System Restoration Working Group for the Satellite and ISO-NE Control Centers, and were complimented by Satellite, NPCC and ISO-NE restoration training programs. The planned phases of restoration were executed as expected. General Rules of Thumb in the plans facilitated tailored solutions including:

- immediate concern for and recognition of nuclear plant safety;
- recognition of the considerable strength of the remaining source (no concerns over switching surges or absorption of charging during restoration of southwest Connecticut);
- coordinated and effective use of generation dispatch and transmission substation equipment for re-synchronization of tie lines to New York and thus the Eastern Interconnection;
- establishment of reliable initial tie loadings (contingencies on either side or loss of tie sustainable); and
- timely action to restore more New England – New York ties and strengthen the interface.

Preparation activities of the NPCC Inter-Area Restoration Coordination Working Group facilitated the joint monitoring of simultaneous restorations of NPCC Control Areas and timely re-synchronization of areas separated by the event.

### **C. Communications**

Most of the New England power system and all of the Maritimes avoided the blackout, and communication services in these areas were not affected. All primary and back-up communications systems (public telephone, Automatic Ring Down circuits, microwave, cell phone, radio) at ISO-New England and the Satellite Control Centers remained in-service. This included the NERC Hotline, which is a public telephone system used to connect the various North American Control Areas (including those whose systems had collapsed) for teleconferences to share information and discuss operations.

In the hours and minutes prior to the disruption, when a series of cascading contingencies were occurring in the Ohio area, no calls were made to any of the NPCC

Control Areas, including ISO-NE, either to alert these systems of the critical conditions developing, or to request assistance.

Within minutes after the disruption, the Midwest ISO (MISO) initiated a NERC Hotline conference call of Security Coordinators. Calls continued on a regular basis and included representatives from IMO, New York ISO, MISO, Michigan, AEP, ISO-NE, Hydro-Québec and PJM. These calls helped to identify the extent of the blackout, and facilitated the coordination of restoration.

ISO-NE maintained communications with generating stations, and established regular teleconferences with the Satellite Control Centers to share information and coordinate system restoration efforts. Representatives from New Brunswick were included in these calls. Elevated communications were also maintained with neighboring Control Areas, including Hydro-Québec, the Maritimes, and especially the severely disrupted New York ISO. Satellite Control Centers established communications with neighboring Satellite-level Control Centers, Local Control Centers, Distribution Centers, generating stations and field personnel.

#### **D. Determination of the Extent of the Blackout**

The first responsibility cited in ISO-NE and Satellite Restoration Procedures is to determine the extent of the blackout. This is accomplished by the Satellites determining the status of their territories and ISO-NE reviewing both the status of Satellite facilities in New England and sharing status reports with neighboring Control Areas and with more removed Control Areas. All information gathered was shared between ISO-NE and the Satellite Control Centers through regular teleconferences. The generation rejection that occurred in New Brunswick was identified immediately after its occurrence by New Brunswick Operators and called into ISO-NE. In less than an hour, the split between New York and most of New England and the Maritimes had been identified and displayed on a one-line diagram. The collapsed Long Mountain/Norwalk area in southwest Connecticut was also identified in this time period. The severe disruptions in the IMO, NYISO, Michigan and northern Ohio areas were ascertained along with the minor effects on the Hydro-Québec system.

#### **Generator Trips in New England**

Beyond the 380 MW of generation tripped in New Brunswick by special protection system action, the severe frequency, power and voltage transients experienced during the system disruption also caused relay protection to trip nearly 2,800 MW of generation in New England. All of the units/facilities that tripped were either in the vicinity of the split that occurred between New York and the New England/Maritimes systems, or within the Long Mountain/Norwalk area of southwest Connecticut, which temporarily broke off with New York before separating from New York and collapsing.

The vast majority of trips occurred in the 4:10 – 4:11 PM time period, when critical transients were being experienced in New England: a rapid frequency decline, a large

power surge to New York, and severe voltage drops in the vicinity of the New England-New York border. All relay protection systems appear to have operated properly for the transient conditions that occurred. Nearly all of the units that tripped were available again for dispatch within a few hours, with minimal generator equipment damage.

Given the prevailing emergency conditions in the Northeast, as many units as possible were brought on as soon as feasible, and they continued to operate into the weekend in order to support reliability and facilitate the supply of emergency power to neighboring Control Areas-especially New York and Ontario.

### **Load Tripped Automatically**

The New England, New Brunswick and Nova Scotia power systems are effectively “in-series” systems, radial to the Eastern Interconnection. The most severe transient frequency dip occurred at approximately 4:10:46 PM, when frequency was roughly 59.6 Hz in New England, 59.5 Hz in New Brunswick, and 59.39 Hz in Nova Scotia.

- In Nova Scotia, a small amount of first block automatic underfrequency load shedding occurred at a remote eastern station near Sydney. Although this particular block was correctly set at 59.3 Hz, actual operation was incorrect with a pickup at 59.5 Hz. A new UFLS relay was subsequently acquired and installed.
- A small amount of automatic underfrequency load shedding also occurred within the Bangor (Maine) Hydro Electric system. Although the transient frequency dip only went down to about 59.6 Hz, based on an old arrangement between Bangor Hydro Electric and New Brunswick, some 5% of Bangor load (roughly 11 MW) was set up to be automatically shed if frequency dipped to 59.6 Hz. This requirement was related to 345 kV separations in Maine, which leave the Bangor area load on the islanded Maritimes systems. Service to the affected load was restored in 6 minutes. Bangor Hydro Electric and New Brunswick have since reviewed the need for this arrangement, and have changed the setting to the standard NPCC first level setting of 59.3 Hz.
- In Vermont, load was interrupted primarily due to low voltage and the opening of transmission line breakers. The voltage in the northwestern part of Vermont oscillated between 0.21 per unit and 1.07 per unit several times over a period of 4.5 seconds. These voltage swings caused the tripping of voltage sensitive equipment – air conditioners, process motors, fans, compressors, adjustable speed drives, computers, and other power electronic loads. One example in northwest Vermont was a silicon chip manufacturer which lost approximately 30 MW of load due to the voltage swings. It is estimated that voltage depressions interrupted approximately 130 MW.

In addition to voltage sensitive equipment tripping off line, several transmission lines in Vermont also tripped as a result of the low voltage. For example, the radial line between Georgia and Highgate tripped, resulting in a load loss of approximately 9 MW.

- Similar severe transient voltage dips occurred in Connecticut, and voltage sensitive loads responded in the same fashion by tripping off and then re-connecting once the voltage stabilized at acceptable levels. Some involved industrial/commercial loads tripped by automatic undervoltage protection. The total load lost in Connecticut due to collapse of the Plumtree/Norwalk area plus severe voltage transients in the remainder of Connecticut was roughly 2,000 MW.

### **Generation/Load Balance**

Approximately 3,100 MW of generation tripped in New England and the Maritimes at the time of separation from New York. At the same time, roughly 3,100 MW of demand, comprised of interrupted load and exports, was lost. This even balance of lost generation and lost demand within the New England/Maritimes island, along with subsequent governor action and HVdc frequency modulation, resulted in frequency excursions more moderate than might have been expected. The widest frequency swings occurred right after the separation, reaching extremes of 60.4 and 59.6 Hz, as measured at Northfield station. The minimum frequency of 59.6 Hz was well above NPCC's 59.3 Hz setting for the first (10%) block of underfrequency load shedding.

### **Generator and HVdc Tie Performance**

Despite some significant frequency excursions during the ten-hour period when the New England/Maritimes systems operated as an island, all nuclear, conventional thermal, and hydro units performed acceptably. HVdc facilities in New England and the Maritimes stayed on-line except for the Highgate HVdc facility in Vermont which was interrupted due to the trip of the 115 kV circuit from Highgate to Georgia substation (K21). During system transients, frequency modulation on the various HVdc ties to Hydro-Québec proved valuable in maintaining nominal frequency.

### **Power Supply to Nuclear Units**

A critical concern in blackout events is the provision of off-site AC power sources to nuclear generators. Nuclear units in New England and New Brunswick experienced severe transients during the disruptions that occurred between 4:10 and 4:12 PM. The system split that occurred between New York and New England/Maritimes, along with an even balance between lost generation and demand and robust pre-event conditions, allowed the New England/Maritimes electrical island to survive, preserving AC supplies to the nuclear units. Some nuclear units did drop into "safe modes" of operation.

### **System Strength**

The manner in which system restoration proceeds depends on the status of the system after the disruption, particularly portions of the system which remain in service. New England system restoration procedures are designed to be applicable to any post-

disturbance system that may be left. In the worst-case scenario of a total blackout, prescribed plans must be followed closely to ensure reliable circuit energizations, island synchronizations, and continuing unit start-ups. Of particular concern are potentially excessive switching surges, high levels of charging and voltage. In the August 14 disturbance, the vast majority of the New England power system remained intact. With such a strong source available, it was immediately clear from ISO-NE restoration training that, restoration efforts could be conducted reliably with manageable voltage perturbations and little concern over switching surges. In fact, the most salient energization involving the three terminal Frost Bridge – Long Mountain 345 kV circuit was successfully performed with the Frost Bridge 345/115 kV transformer being energized simultaneously with the 345 kV line.

#### **E. Restoration Summary**

##### **Vermont**

In the wake of the severe transients and the system split between Vermont and New York that occurred between 4:10:46 and 4:10:52 PM, there were three 115 kV transmission lines left out of service in Vermont: the Plattsburgh – Sandbar PV20 line; the Georgia – Highgate K21 line (including the Highgate Converter import of 200 MW); and the Bennington – Hoosick K6 line. The Blissville – Whitehall K7 line stayed in service, but lines farther west opened so that Vermont was connected to a radial load pocket in New York for some time following the Vermont-New York split.

The re-closing on the circuits operated as designed. The Bennington – Hoosick K6 line automatically re-closed but tripped out again. The PV20 line opened at Sandbar and remained open. The Plattsburgh end stayed in supplying load at Vermont's South Hero substation. The Georgia – Highgate K21 line successfully re-closed.

At this point, the three Vermont connections to New York were severed and Vermont was relying on other transmission ties to Massachusetts and New Hampshire. One of the first actions to restore the reliability of the Vermont transmission system was to re-start the Highgate converter and import 150 MW into Vermont. Further operator actions included bringing on Vermont thermal generators, arming the under-voltage load shedding scheme, and manning critical substations.

##### **Long Mountain/Norwalk Area**

CONVEX restoration efforts can be broken into two parts: restoration of the load that was manually shed to stabilize conditions in western Massachusetts and Connecticut, and restoration of the collapsed Long Mountain/Norwalk area.

Between 4:40 and 5:50 PM, approximately 400 MW of fast-start generation synchronized to the system. Once system security was reestablished, restoration of the load which had been manually shed began at 5:42 PM. CONVEX continued to restore substations through 7:28 PM. Once the substations were reenergized, ISO-NE and



CONVEX coordinated with the distribution companies to restore customer load. The load was restored based on the capability of the system.

The Long Mountain/Norwalk area stayed connected to the New York system for a brief period until the transmission system finally separated from New York. CONVEX requested that CL&P and UI man the substations in the area affected. Manual switching was required to ensure that the distribution system was separated from the transmission system. This allowed a controlled restoration of the transmission system followed by the restoration of customer load.

The Norwalk-Stamford and Danbury areas were tied together at 9:50 PM. At this point in the restoration the transmission system was restored except for the area west of Glenbrook Substation. Over the next hour the restoration of the transmission system west of Glenbrook continued. By 11:23 PM the Connecticut transmission system was restored except for the New York ties and the 115 kV high pressure fluid filled cables to Middle River Substation. CONVEX continued working with CL&P throughout the night to energize the distribution buses to restore customer load. By 1:35 am, other than the Middle River Substation, all bulk substation distribution buses were energized.

CL&P was restoring customer load when, at 5:44 am on August 15, the Southington-Frost Bridge 329 Line tripped due to a conductor splice failure. Along with the lack of southwest Connecticut generation, this compelled CONVEX to order a halt to load restoration at 7:00 am. The normal morning load pick-up was resulting in the southwest Connecticut transmission system operating at its transmission transfer limit. Generation restoration throughout the morning prevented CONVEX from having to implement load shedding, but there was no margin to allow continued restoration. By 12:00 noon generation pick-up provided sufficient transmission system relief to allow load restoration to continue. CL&P restored essentially all load affected by the blackout by the evening of August 15.

#### **F. Synchronization**

In the event of a catastrophic separation and islanding of the New England and New York power systems, New England Restoration Plans call for re-synchronization of the two systems by energizing the 393/312 circuit from Alps substation in New York to Northfield substation in New England. Synchronizing equipment, generation and circuit breakers at the Northfield Pumped Storage facility are to be used to effect synchronization. This plan had been developed by the NEPOOL System Restoration Working Group and repeatedly shared with ISO-NE and Satellite Control Center Operators and New England field and generating station personnel at annual New England System Restoration Exercises and in-house training. It was also shared with New York Operations personnel at biennial NPCC Operator Training Seminars. While involving known difficulties unique to Northfield substation, this plan was successfully implemented on August 14.

At 1:53 am on Friday, August 15th, the New York and New England systems were re-synchronized with minimal power flow on the 312/393 tie line. This in effect re-connected the New England/Maritimes island to the Eastern Interconnection, since New York had already reestablished ties to the grid.

The following four New England – New York tie lines were restored in the early morning hours of Friday August 15:

03:33 Long Mountain - Pleasant Valley 345 kV 398 Line  
04:01 Bear Swamp – Rotterdam 230 kV E205W Line  
04:24 Sandbar – Plattsburgh 115 kV PV20 Line  
05:40 Bennington – Hoosick 115 kV K6 Line

The Blissville – Whitehall 115 kV K7 line was restored at 10:43 am on the 18th, once New York's power system was secure. The Norwalk Harbor – Northport 138 kV 1385 circuit could not be restored soon after the system disruption due to loss of cable insulation pressure. An unsuccessful re-closure attempt raised concerns over the condition of this circuit's Phase Angle Regulator at Northport. But test results proved negative, and the 1385 circuit was returned to service at 1:49 am, August 24, 2003.

#### **G. Emergency Assistance to New York and Ontario**

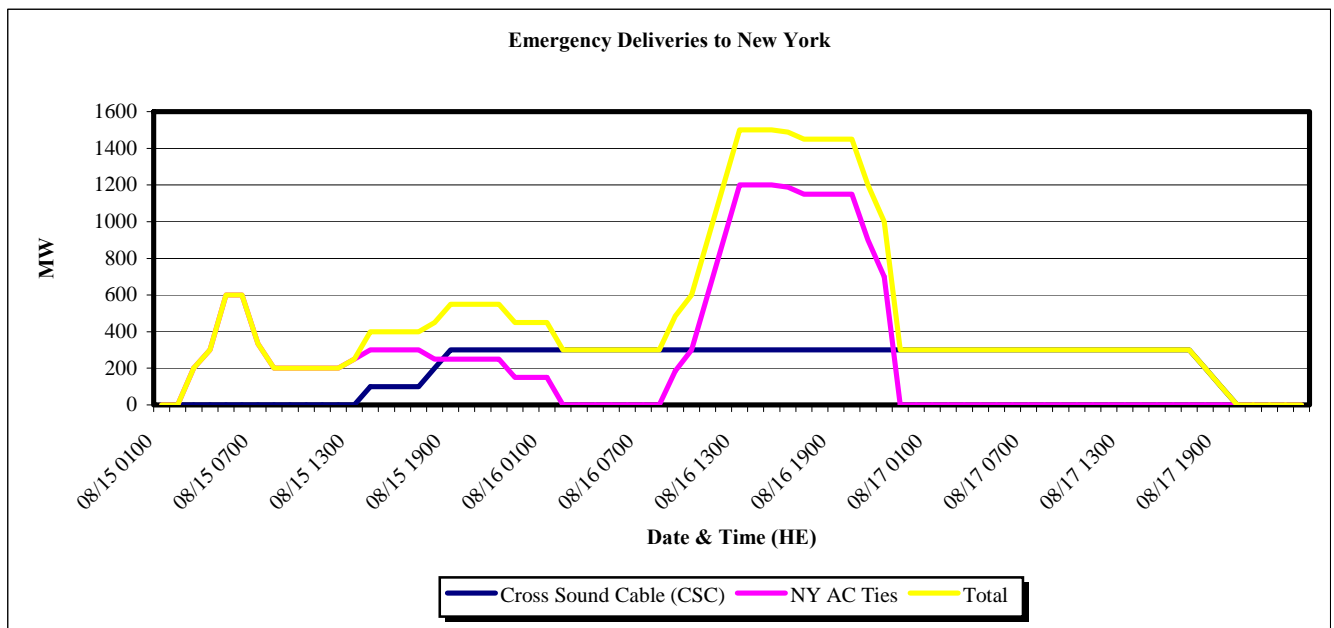
As additional ties to New York were restored, delivery of emergency capacity and energy increased to as much as 600 MW until the 345 kV, 329 line from Frost Bridge to Southington was lost at 5:44 am on August 15th. The loss of the 329 line may have been caused by damage due to the power swings preceding the system separation. After the loss of the 329 line, emergency deliveries were reduced to between 150 and 300 MW, due to thermal restrictions on the New York/New England Interface.

At 3:27 am on the 16th, the 329 line from Frost Bridge to Southington was restored to service. The restoration of the 329 line greatly increased the export capability from New England to New York. At 8:00 am, emergency deliveries on the AC ties began again as loads increased in New York and IMO. By midday, emergency capacity and energy deliveries reached 1,200 MW; they then trended downward to 700 MW by 10:00 PM, at which time deliveries went to zero.

The Cross Sound Cable is a new HVdc tie between New Haven, Connecticut and Shoreham, New York on Long Island. This facility had undergone acceptance testing prior to August 14, 2003, but had not been released to ISO-NE and the New York ISO for dispatch due to a moratorium. On August 14<sup>th</sup>, at 11:42 PM, the U.S. Secretary of Energy declared that an emergency existed due to the blackout. Both ISO-NE and the New York ISO were directed to require the Cross Sound Cable Company, LLC to operate the Cross Sound Cable as the two ISOs deemed appropriate to secure reliable operation of the transmission grid during this emergency. Pursuant to this order, the operating personnel for the Cross Sound Cable were contacted, and directed to make the facility ready to deliver power.

Between 1:00 PM, August 15th and 5:00 PM on the 17<sup>th</sup>, the cable carried between 100 and 300 MW to aid the restoration and stabilization of the Long Island Area of the New York grid. ISO-NE and the New York ISO allowed the Cross Sound Cable to come offline by 7:00 PM on August 17th, when the New York ISO no longer required emergency assistance.

A chart detailing New England to New York AC deliveries, and Cross Sound Cable Emergency HVdc deliveries, appears below. This figure also shows total deliveries to the New York ISO, which reached as high as 1,500 MW. The delivery of this emergency capacity and energy to New York allowed the New York ISO and IMO operators to maintain reserves on their system and reduce the likelihood of feeder rotations (rotating blackouts) as they continued to restore the blacked out areas of their respective systems.



**Figure 2 Emergency Deliveries to New England**

**H. Event Milestones**

To summarize the system restoration efforts made in New England, for each high level restoration milestone, a chronology list of events is provided as follows:

**Restoration of Load Manually Shed to Achieve Stabilization**

Completed by 16:40, CONVEX ordered a total of roughly 500 MW load shed, 400 MW in Connecticut and 100 MW in Western Massachusetts.

## **Restoration of the Transmission System**

### **Vermont**

- Plattsburgh – Sandbar PV20 line, tripped at Sandbar at approximately 16:10:52, remained in at Plattsburgh and supplying the South Hero load; restored to service at Sandbar at 4:17:03 on August 15, 2003.
- Georgia – Highgate K21 line opened at 16:20:52, successfully re-closed.
- Bennington – Hoosick K6 line, opened at about 16:10:48. At 16:11:22, it automatically re-closed through synchro-check relays but immediately re-opened. Closed at 5:40:49 on August 15, 2003.

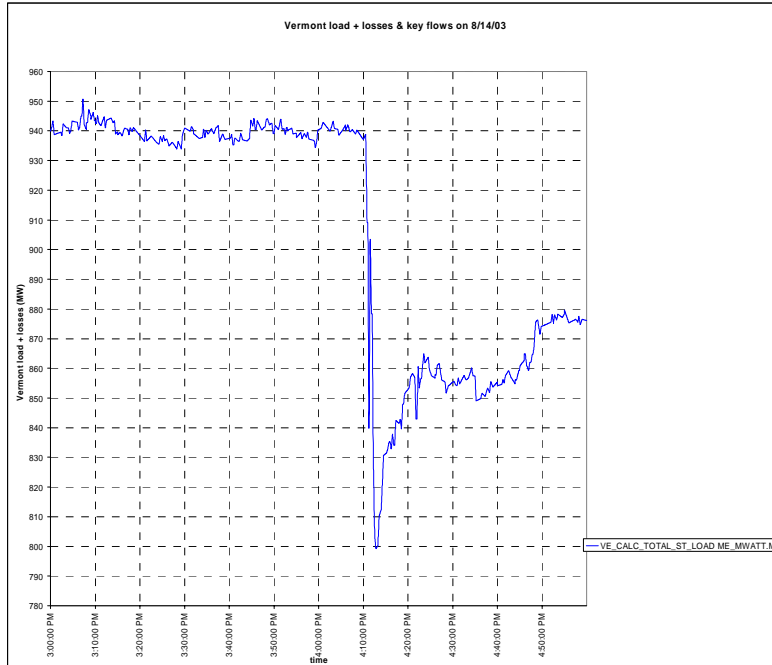
### **Long Mountain/Norwalk Area**

- At 19:15 the Stevenson to Plumtree transmission path was reenergized marking the beginning of the transmission system restoration.
- To expedite transmission restoration, CONVEX split the system at Norwalk Substation, assigning one team to restore the Norwalk-Stamford area, while a second team restored the Danbury area.
- At 21:50 the Norwalk-Ridgefield-Peaceable 1470 Line was closed at Norwalk Substation so that the Norwalk-Stamford and Danbury areas were tied together.
- By 23:23 the Connecticut transmission system was restored except for the New York ties and the 115 kV high pressure fluid filled cables to Middle River Substation.
- By 01:35 all bulk substation distribution buses were energized other than the Middle River Substation.
- Southington-Frost Bridge 329 Line tripped at 05:44 on August 15 due to a conductor splice failure.

## **Restoration of Load**

### **Vermont**

- In Vermont, the primary causes of load interruption were low voltage and opening of transmission line breakers. The graph below shows the Vermont load starting at 3:00 PM and ending at 5:00 PM on August 14<sup>th</sup>. This graph represents the total load lost as a result of the under-voltage experienced by the voltage sensitive equipment and the load lost as a result of a radial line that tripped. As shown by the graph, the Vermont load prior to the event was approximately 940 MW. Immediately after the event load dropped to approximately 800 MW, indicating a load reduction in Vermont of about 140 MW. Over the next 10 minutes the load rose to about 860 MW and remained at that level for approximately 30 minutes. The rest of the Vermont load lost was recovered within one hour of the event.



**Figure 3 Vermont Load + Losses**

**Long Mountain/Norwalk Area**

- CONVEX manually shed roughly 500 MW of firm load from 16:32 through 16:40 to stabilize the system.
- Over the next hour, approximately 400 MW of fast-start generation synchronized to the system.
- Once system security was reestablished, restoration of the load which had been manually shed began at 17:42. CONVEX continued to restore the substations through 19:28. Once the substations were reenergized, ISO-NE and CONVEX coordinated with the distribution companies to restore customer load. The load was restored based on the capability of the system.
- CONVEX ordering a halt to load restoration at 07:00 due to the trip of 329 Line.
- By 12:00 the generation pick-up allowed enough transmission system margin to enable continuation of load restoration.
- By the evening of August 15, CL&P restored essentially the entire load lost in the blackout.

**Restoration of Tie-lines**

- At 1:53 am on Friday, August 15th, the New York and New England systems were re-synchronized on the 312/393 tie line.
- The following four New England – New York tie lines were restored in the early morning hours of Friday August 15:  
03:33 Long Mountain - Pleasant Valley 345 kV 398 Line  
04:01 Bear Swamp – Rotterdam 230 kV E205W Line

04:24 Sandbar – Plattsburgh 115 kV PV20 Line

05:40 Bennington – Hoosick 115 kV K6 Line

- At 10:43 on August 18, 2003 the Blissville – Whitehall 115 kV K7 line was restored.
- At 01:49 on August 24, 2003, the Norwalk Harbor to Northport 138 kV 1385 circuit, including the Northport Phase Angle Regulator, was returned to service.

### **Emergency Power Deliveries**

- At 01:53 on August 15, ISO-NE began delivering 200 MW of emergency capacity and energy to NYISO. As additional ties to New York were restored, delivery of emergency capacity and energy increased to as much as 600 MW.
- At 05:44 on August 15, the loss of the 329 line forced the emergency deliveries to be reduced to 150 to 300 MW, due to thermal restrictions on the New York/New England Interface.
- By hour ending 02:00 on August 16, 2003, the load had dropped off and the system was stable enough in New York that the emergency capacity and energy transfers were reduced to zero.
- At 03:27 on August 16, the 329 line from Frost Bridge to Southington was restored to service, which greatly increased the export capability from New England to New York. At 08:00 that day, emergency deliveries on the AC ties resumed as NYISO and IMO loads increased.
- By midday, the emergency capacity and energy deliveries on the AC ties increased to as much as 1,200 MW and then trended downward to 700 MW by hour ending 22:00, at which time deliveries were no longer needed.

### **Emergency Order to Use the Cross Sound HVdc Cable**

- On August 14, 2003, at 23:42, the Secretary of Energy Spencer Abraham declared that an emergency existed due to the blackout. In DOE Order No. 202-03-01, declaring the emergency, both ISO-NE and NYISO were directed to require the Cross Sound Cable Company, LLC to operate the Cross Sound Cable as the two ISO's deemed appropriate to secure the reliable operation of their transmission grids during this emergency.
- At 13:00, for hour ending 14:00 on August 15, ISO-NE delivered 100 MW of emergency capacity and energy to NYISO to aid in the restoration and stabilization of the grid on Long Island Area.
- The delivery increased to 300 MW at 18:00, for hour ending 19:00, and stayed at 300 MW.
- At 17:00 on August 17, when the delivery dropped to 200 and 100 MW, respectively, in the proceeding two hours.
- ISO New England and the New York ISO allowed the Cross Sound Cable to come offline by 19:00 on 8/17/03, when the New York ISO no longer required the emergency capacity and energy deliveries.

### **Utilization of Emergency Procedures**

- To stabilize operations within remaining systems, actions taken include the switching of shunt devices, manual load shedding, belaying automatic Desired Dispatch Points and switching to manual dispatch orders and, appropriately opting for flat frequency or tie line bias control depending on the status of tie lines.
- The following NEPOOL Operating Procedures had been implemented during and after the blackout:
  - NEPOOL Operating Procedure 4 – Action During a Capacity Deficiency was implemented at 06:50 on August 15th, and cancelled at 23:45 on August 15th;
  - NEPOOL Operating Procedure 6 – System Restoration was effectively implemented at 16:11 on August 14th through 03:50 on August 16th; and
  - NEPOOL Operating Procedure 7– Action In An Emergency was implemented by CONVEX at 16:33 on August 14th through 23:26 on August 14th.

#### 7.4 **Recommendations of the ISO New England, Inc.**

##### **The Cure**

ISO-NE recommends to the industry that the size, shape, authority and responsibility of Operations Centers throughout the United States must be clear and coordinated with the following underlying principles:

##### **7.4.1 Infrastructure**

The proposed NERC functional model should reflect the concepts below and ensure that it will not create or promote disjointed operational structures that could create missed responsibilities, operational confusion and inaction.

- 7.4.1 Operations organizations should avoid large “Swiss cheese” territorial footprints.
- 7.4.2 Levels of operations must have clear documented responsibilities with ultimate authority at one entity.
- 7.4.3 Operations Centers must be able to observe their entire system and must have adequate analytical tools, operating limits and mechanisms for timely physical action.
- 7.4.4 Interdependent operations functions should not be fragmented and distributed to numerous, separate entities.

##### **7.4.2 Reliability Criteria**

- 7.4.2.1 Reliability criteria must be mandatory throughout the industry, especially timely recovery from contingencies, including manual load shedding if needed.
- 7.4.2.2 National and Regional reliability criteria should be considered minimum requirements.
- 7.4.2.3 Operating Procedures should be standardized across broader regions.
- 7.4.2.4 Chief Executive Officers, Chief Operations Officers or Vice Presidents from RTOs, ISOs, Reliability Coordinators, Control Areas, and Transmission Owners should certify their organizational compliance with NERC and any other applicable Regional or Area reliability standards.
- 7.4.2.5 Reliability Standards should become enforceable nationwide with penalties. An entity with flagrant violations should be sanctioned or considered eligible for removal from the Market.
- 7.4.2.6 Transmission Owners should establish or maintain reliable standards for vegetation management in transmission corridors and comply with them.

### **7.4.3 New England Operations Personnel and Infrastructure**

Recognizing the continuing effectiveness and clarity of the operations criteria and infrastructure within New England, ISO-NE makes the following recommendations to the Participants:

- 7.4.3.1 The reliability criteria for operating the New England power system presently defined in NEPOOL Operating Procedures and ISO-NE System Operating Procedures (all of which stem from NERC and NPCC criteria) should continue as the framework for power system and market operations and any future changes to Standard Market Design.
- 7.4.3.2 The operational responsibilities and authorities defined in present NEPOOL Operating Procedures, ISO-NE System Operating Procedures and Satellite Operating Procedures should be maintained and reflected in any future infrastructure changes.
- 7.4.3.3 ISO-NE should continue to act as the single entity with final operational responsibility and authority for the overall New England bulk power system. To maintain “a single set of hands on the wheel” and avoid confusion and inaction, key operational authorities of ISO-NE, including final authority over transmission and generation dispatch decisions, should not be segmented, split or delegated to other entities within the New England operations footprint.

Satellite Control Centers should continue to assume and perform responsibilities given to them by NEPOOL and ISO-NE procedures, consistent with a more focused look at their local sub-areas of New England.

### **7.4.4 Voltage/Reactive Performance**



- 7.4.4.1** The Voltage Task Force of the Master Satellite Heads should perform a final, detailed review of the plots of generator voltages, confirm the excessive voltage issue found to date, and determine if any other voltage schedule issues exist. Any warranted corrective action should be taken to change voltage schedules or actual voltage operating practices.
- 7.4.4.2** ISO-NE has already contacted the generating stations it believed were not operating in automatic voltage regulating mode, confirmed that such was the case, and mutually effected corrective action by switching the regulators from reactive power control to voltage control mode. The Voltage Task Force should perform a final detailed check of reactive power (VAR) plots for all other major units to ensure that automatic voltage regulator responses are proper.

NEPOOL Participants, Satellite and ISO-NE Control Centers should maintain their high levels of commitment to the following operating procedures and activities related to voltage/reactive security:

- NEPOOL Operating Procedure No. 17 establishing Standards for Load Power Correction and auditing compliance to same;
- Testing of generator reactive power limits;
- NEPOOL Operating Procedure No. 12 – Voltage and Reactive Control including generator voltage schedules and limits. The survey results indicate that a small fraction of small generating resources (<20 MW resources) were found not to have Automatic Voltage Regulators or were unable to operate in the Automatic Voltage Control mode. ISO-NE is reviewing the impact of this finding. If analysis determines that this status is acceptable from a reliability perspective, operating policies and procedures in New England will be revised accordingly.
- Area Voltage Operating Guides, including key transmission station voltage limits and select reactive reserves;
- Interface Voltage Limit Guides and Software Calculators; and
- NEPOOL Operating Procedure No. 14 – Technical Requirements for Generation, Dispatchable and Interruptible Loads.

#### **7.4.5 Restoration Plans**

NEPOOL Participant, Satellite and ISO-NE Control Centers should maintain their high levels of commitment to the following activities related to system restoration:

- maintenance of ISO-NE and Satellite Restoration Procedures;
- annual System Restoration Exercise;
- annual Black Start Unit Testing;
- maintenance or expansion of the fleet of Black Start Units, including adequate compensation;
- NPCC Compliance testing of Key Facilities for System Restoration;
- NPCC Operator System Restoration Training; and

- ISO-NE and Satellite Operator System Restoration Training.

#### **7.4.6 Stabilizing Remaining System(s)**

Satellite and ISO-NE Control Centers should maintain their high levels of commitment to:

- conduct Load Shedding Exercises involving ISO-NE, Satellite and Regional Dispatch Operators every other month; and
- emphasize throughout System Operating Procedures and Operator training that “any Control Room Operator has the authority to take action(s) required to comply with NERC Policy.” The Master Satellite Heads should review their procedures for load shedding. Operators should be able to evaluate and implement load shedding effectively following a major system disturbance.

The System Restoration Working Group of the Master Satellite Heads should note the potential need for actions to stabilize operations within remaining systems in System Restoration Procedures. These actions should include the switching of shunt devices, possible manual load shedding, belaying automatic Desired Dispatch Points and switching to manual dispatch orders, and appropriately opting for flat frequency or tie line bias control depending on the status of tie lines.

#### **7.4.7 Frequency Control and Generation Dispatch Within the Island**

The following recommendations will be pursued to improve normal interconnected operations and islanding performance:

- 7.4.7.1** The Training, Documentation and Compliance Group will reinforce the steps involved with switching from tie line bias to flat frequency or flat tie control in the early stages of an identified island. The training will include recognition of islanding events and determining what the appropriate control mode would be for the ISO-NE and Maritimes Control Areas.
- 7.4.7.2** It is recommended that the computed natural frequency bias response for New England be used with flat frequency control to prevent oscillatory behavior during periods of separation. The System Operations Control Performance Principal Engineer will work with the Energy Management Systems group to develop software that automatically selects the natural frequency bias, computed by prior studies, as soon as the operator selects flat frequency operation under island conditions.
- 7.4.7.3** An Islanding Operational Support Display will be developed by the System Operations Control Performance Principal Engineer in coordination with the Energy Management Systems group to provide key islanding information to the operator, including the ability to efficiently select and de-select flat frequency AGC control mode operation. The display should also include plots of available and selectable frequency sources distributed throughout

the Control Area, as well as breaker status and/or tie line flow data to assist the operator in determining the topological boundaries of the island. Once the display is ready for operation, the system operators will be trained in its use, and it will be implemented.

- 7.4.7.4** The System Operations Control Performance Principal Engineer will work with the Markets Development Forecast Principal Engineer to further analyze the need for enhancements to the load forecast used in unit dispatch software under islanding scenarios. He will make a final recommendation to the Manager of Operations based upon this analysis.
- 7.4.7.5** A list of increasingly aggressive recommendations to enhance governor response in the ISO-NE Control Area will be led by the System Operations Control Performance Principal Engineer. The following actions will be included:

- Complete the analysis of substantial frequency deviations that occurred during islanding;
- Continue ISO-NE's existing frequency response monitoring project at a higher priority;
- Interview plant personnel responsible for tuning the plant control systems to better understand the physics and control strategies that are deployed, particularly with larger combined cycle facilities; and
- Define requirements for governor response and incorporate them into appropriate criteria.

#### **7.4.8 Re-Closing and Switching**

- 7.4.8.1** The automatic re-closures that occurred on the New England – New York tie lines should be investigated further by the Master Satellite Heads to ensure that these re-closures were: a) appropriate; b) consistent with the normal, steady state design intent of automatic re-closing systems; and c) while not desirable, acceptable for the rare event which occurred on August 14, 2003.
- 7.4.8.2** The manual re-connects between the New England/Maritimes island and New York should be investigated and methods to avoid these types of re-connects should be identified. Results should be incorporated into switching procedures and training – and, if appropriate, into System Restoration Procedures by the System Restoration Working Group. The investigation should include such possibilities as: a) requiring the opening of disconnects on circuits that comprise a split between systems; b) changing equipment at all or key transmission stations such that manual re-closures must go through permissive sync-check instead of just manual sync-check; and c) use of automatic paging systems or other means of notification to field personnel to alert them to events involving electrical islanding and increasing sensitivities to the possible need for synchronizations before manual closures of breakers.
- 7.4.8.3** The Master Satellite Heads should investigate the methods and procedures used to energize transmission into a collapsed area. Satellite Trainers should incorporate these procedures into the system restoration training.

### **7.4.9 Synchronizing Islands**

- 7.4.9.1** The NPCC Inter-Area Restoration Coordination Working Group, and the New England System Restoration Working Group, should research the questions raised by field personnel regarding frequency and voltage match requirements for the synchronization of electrical islands. They should establish guides for re-synchronization of islands. These guides should be incorporated into System Restoration Procedures.

### **7.4.10 Control Room Logistics**

- 7.4.10.1** The System Restoration Working Group should modify the ISO-NE and Satellite Restoration Procedures to: 1) include the assignment of personnel to each Operator Desk to transcribe and reference key decisions and actions that occur during these emergency operating conditions, and 2) call for regular staff meetings within Control Rooms to disseminate information and promote and coordinate activities.
- 7.4.10.2** The Master Satellite Heads should arrange for telephone conversations by technical support personnel (e.g., the Restoration Coordinator) to be recorded on tape.
- 7.4.10.3** The Master Satellite Heads should ensure that work space within or bordering Control Rooms and used by support personnel during system emergencies is adequate, with appropriate computer terminals accessing real-time software and data.
- 7.4.10.4** ISO-NE and Satellite personnel should create “Restoration Packs” similar to the “Evacuation Packs” used when Control Rooms evacuate to Back-Up Control Centers. These Restoration Packs will facilitate response to system blackout events by providing rapid and easy access to needed information and equipment.
- 7.4.10.5** To facilitate communications between the Satellite and ISO-NE Control Centers, the Master Satellite Heads should consider use of a continuously open teleconference line during emergencies and investigate the use of video conferencing.

### **7.4.11 Software/Hardware Performance**

The ISO New England Energy Management Systems Department and the System Operations Department should jointly design, develop, deliver and train on the following tools to improve the ability of operators to identify precisely the status of the system following a major disturbance:

- 7.4.11.1** Working with the New York ISO (NYISO), immediately procure information regarding the status of all breakers two busses west of the interconnection points of the New England and New York Control Areas.

- 7.4.11.2** Design and implement overview displays for all of the dispatch areas observable in the Unit Dispatch Software, including Maine, New Hampshire, Vermont, Mass Boston, Northeast MA, Southeast MA, Western MA, Central MA, Rhode Island, Southwest Connecticut, and Connecticut. These overview displays must include station identification, voltages, line designation, line flows and direction, and be linked to the individual substations. These overview displays should be capable of being used across real-time and study applications, including: study powerflow and security analysis; state estimation and SCADA; and real-time contingency analysis. Finally, the displays for the advanced study applications should allow the operator to view conditions in both pre- and post-contingency modes on the same display, and violations of the Normal, LTE and STE ratings should be color coded to allow operators to see overloads.
- 7.4.11.3** Design and implement an overview display of system voltages similar to the “Voltage and Reactive Surveys” displays within Appendix B of NEPOOL Operating Procedure No. 12, Voltage and Reactive Control. This display should provide the operator with critical station voltages throughout the New England system. It should include Heavy and Light Load schedules, Maximum and Minimum allowable voltages, and the desired voltage schedule for individual facilities. The display should also detail the leading and lagging capabilities of critical generators on the interconnection, and provide alarms to operators if any of the limits are violated.
- 7.4.11.4** Design and implement Interconnection Monitor displays in New England for the following Control Areas: NYISO, New Brunswick and the Maritimes, TransÉnergie, the Independent Market Operator of Ontario (IMO), and PJM Classic. These displays should include the following information and be similar to the ISO-NE System Summary display: ACE, last ACE crossing, Load, Total Generation, Interchange, Reserve Requirements vs. Instantaneous Actual Reserves, Frequency, and Critical Interface Limits vs. Actual Critical Interface Flows.
- 7.4.11.5** The System Architecture and Technology Department, working with System Operations, should investigate the feasibility and propriety of installing operator visualization tools such as “Power World” or other similar programs to graphically display system information in a more user-friendly format.
- 7.4.11.6** The Information Technology group should continue with its efforts to procure a new data historian tool, and implement the new tool as soon as possible.
- 7.4.11.7** The Master Satellite Heads should charge appropriate IT staff to; 1) discern the reasons for the hardware/software failures in the Midwest that were major contributors to the cause of the blackout, 2) determine if the infrastructure of Satellite and ISO-NE Control Centers are susceptible to similar failures, and 3) if so, recommend mitigating actions.
- 7.4.11.8** The Master Satellite Heads should charge the New England Data Communications Task Force to investigate the reasons for failures of the RTUs, and/or transmittal of the RTU data to the SCADA and Satellite

Control Centers. The Task Force should recommend action geared to avoid the failures under similar circumstances in the future.

#### **7.4.12 Transient Recording Devices**

- 7.4.12.1** ISO-NE System Planning personnel and the NEPOOL Stability Task Force should review the effectiveness and adequacy of transient recording devices in New England, and implement any warranted change-outs or additions.

#### **7.4.13 Follow up Studies, Telephone Service, Southwest Connecticut Split and Event Simulations**

- 7.4.13.1** In a collaborative effort, the Master Satellite Heads and ISO-NE System Planning personnel should work with telephone service providers to assess the adequacy of back-up power supplies for telephone service, and recommend any warranted action to secure these back-up power supplies.
- 7.4.13.2** Personnel from Transmission Owners and ISO-NE Near-Term Transmission Reliability and System Planning departments should maintain participation in studies conducted by the MEN Operations Studies Working Group and NPCC Study Groups (e.g., SS-38) to re-create and assess the August 14, 2003 event.
- 7.4.13.3** ISO-NE System Planning should determine how the future installation of the 345 kV transmission loop in Southwest Connecticut would have affected the system separation that day.

## Appendix A

### Northeast Power Coordinating Council Inter-Control Area Restoration Coordination Working Group (NPCC Working Group CO-11)

#### SCOPE

##### **Purpose**

The objective of the Inter-Control Area Restoration Coordination Working Group (IRCWG) is to achieve effective and coordinated power system restoration among the NPCC Control Areas and with adjacent jurisdictions.

##### **Scope of Activities**

1. Review the restoration plans of the NPCC Control Areas to identify in each individual plan:
  - general elements of the restoration plan
  - communication protocols employed
  - roles and responsibilities of the restoration participants
2. Recommend enhanced procedures for the coordination of inter-Area restoration.
3. Identify areas where mutual assistance can be provided and the extent to which each system can rely on its neighbors for assistance.
4. Review NPCC documentation, including, but not limited to, the following documents:
  - “Emergency Operation Criteria”
  - “NPCC Inter-Control Area Power System Restoration Reference Document”

5. Identify and recommend revisions to the Control Area training plans.
6. Review and maintain the NPCC list of **Key Facilities** and associated **Critical Components**.
7. Review relevant contingency events and system disturbances to determine findings and recommendations towards optimizing coordinated restoration.
8. Monitor evolving NERC activities relative to system restoration.
9. Assist the Compliance Monitoring and Assessment Subcommittee as appropriate.
10. The IRCWG will report to the System Operations Managers Working Group (NPCC Working Group CO-8).

NPCC Reliability Coordinating  
Committee  
November 4, 2003



## Appendix B

### Glossary of Available Reports on the Power System Collapse of August 14, 2003

Report	Internet Address
“U.S.-Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations”	<a href="https://reports.energy.gov/BlackoutFinal-Web.pdf">https://reports.energy.gov/BlackoutFinal-Web.pdf</a>
“IMO August 2003 Blackout- Restoration Evaluation Report”	<a href="http://www.theimo.com/imoweb/pubs/corp/EPTF_Aug2003_RestorationEvalRpt.pdf">http://www.theimo.com/imoweb/pubs/corp/EPTF_Aug2003_RestorationEvalRpt.pdf</a>
“Report of the NYISO Restoration Working Group on the August 14, 2003 System Event”	<a href="http://www.nyiso.com/topics/outage2003_info/investigation_data/nyiso_rwg_report_final.pdf">http://www.nyiso.com/topics/outage2003_info/investigation_data/nyiso_rwg_report_final.pdf</a>
“Blackout 2003-Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout”	<a href="http://www.iso-ne.com/special_studies/August_Blackout_Report/">http://www.iso-ne.com/special_studies/August_Blackout_Report/</a>