Review of Interconnection Assistance Reliability Benefits

June 29, 2004

NPCC CP-8
Working Group

NORTHEAST POWER COORDINATING COUNCIL

CP-8 WORKING GROUP

REVIEW OF INTERCONNECTION ASSISTANCE RELIABILITY BENEFITS

Approved by the NPCC Reliability Coordinating Committee

July 14, 2004

EXECUTIVE SUMMARY

NPCC's CP-8 Working Group, under the auspices of the Task Force on Coordination of Planning was charged to:

1. Estimate (on a consistent basis) the amount of interconnection assistance available to the NPCC Areas for today's system (2003) and the near term (2006);
2. Review each NPCC Area's current estimates of interconnection benefits used to meet the NPCC Resource Reliability Criterion; and,
3. Verify that the current levels of interconnection benefits assumed in each Area's resource adequacy assessments are reasonable and do not result in overstating any Area's reliability.

The General Electric (GE) Multi-Area Reliability Simulation (MARS) program was used to estimate NPCC Area Annual Tie Benefit for a hypothetically "At Criteria" and "As Is" year 2003 and year 2006 system representation. GE Energy was retained by the CP-8 Working Group to conduct the simulations.

Table EX-1 shows the interconnection assistance reported in recent Area studies and the results from this Review. When interpreting these results, there are two important points that are critical to recognize; first, the data and assumptions used in recent Area studies may have been considerably different from that used in these studies, and second, the underlying methodology varies for each NPCC Area.

Table EX – 1
Comparison of Assumed and Estimated
ANNUAL INTERCONNECTION ASSISTANCE – MW

NPCC Area (Date of Review)	Assistance Reported in Recent NPCC Triennial Reviews of Resource Adequacy	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2006
Québec (11/02)	0	2,720 – 3,380
Maritimes (12/01)	0	930 - 1,200
New England (11/02)	1,800 [1]	487 - 3,975
New York (06/02)	2,100	3,775 – 7,150
Ontario (07/03)	1,500	3,150 – 4,050

After consistently applying the methodology and assumptions used in this Review to all NPCC Areas, using the same multi-Area reliability model, and after reviewing, on a consistent basis, the NPCC Area estimates of interconnection benefits used to meet the NPCC Resource Reliability Criterion, the CP-8 Working Group concluded that the interconnection assistance values reported by NPCC Areas in their recent resource adequacy assessments appear to be reasonable and do not overstate interconnection benefits.

Recommendations

The CP-8 Working Group recommends that NPCC's Review of Interconnection Assistance Reliability Benefits be updated once proposed transmission projects (or their combination) are further quantified in order to identify the impact on the NPCC Area interconnection assistance estimated for the 2006 time frame.

[1] The results of a recent tie reliability benefits study by the Independent System Operator of New England showed that the amount available can be as low as 30 MW and as high as 3,300 MW, depending on the assumptions.

NPCC CP-8 WORKING GROUP

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The members of NPCC's CP-8 Working Group wish to acknowledge the contributions of Mr. Glenn E. Haringa, GE Energy.

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1.0 INTRODUCTION

The objective of CP-8 Working Group's Review of Interconnection Assistance Reliability Benefits was to estimate (on a consistent basis) the amount of interconnection assistance available to NPCC Areas for today's system (2003) and the near term (three-year period), review each NPCC Area's current estimates of interconnection benefits and verify that the current levels of interconnection assistance assumed in each Area's resource adequacy assessments are reasonable and do not result in overstating any Area's reliability. NPCC Document A-02, Basic Criteria for Design and Operation of Interconnected Power Systems [1], Section 3.0 Resource Adequacy – Design Criteria states– "Each Area's probability (or risk) of disconnecting firm load due to resource deficiencies shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day/year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

In meeting this objective, the CP-8 Working Group used General Electric's (GE) Multi-Area Reliability Simulation (MARS) program to examine interconnection assistance for each of the NPCC Areas. GE Energy was retained by the CP-8 Working Group to conduct the simulations. The CP-8 Working Group:

1. Used the current NPCC CP-8 Working Group's GE MARS database to develop a model suitable for the 2003 and 2006 time periods;
2. Considered the impacts of Sub-Area transmission constraints;
3. Worked with neighboring Areas to develop a detailed near-term GE MARS reliability representation for regions bordering NPCC.

This evaluation utilized a common multi-area reliability program and a consistent set of assumptions and methodology to evaluate each NPCC Area's interconnection assistance. Area loads were correlated based on the 1995 historical load period. Area load forecast uncertainties and emergency operating procedures were modeled on a consistent basis. The study recognized that each of the Canadian utilities have dispatchable loads [interruptible loads] which are operating procedures restricted for use solely by that utility.

[1] See: http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf.

2.0 AREA INTERCONNECTION ASSISTANCE

Each NPCC Area is responsible for demonstrating that sufficient resources are available to meet its load and operating reserve in accordance with the NPCC criteria, taking into consideration the potential benefit arising from reserve sharing through interconnections with neighboring Areas. Each NPCC Area is required to comply with the requirements outlined in NPCC Document B-08 [1], "Guidelines for Area Review of Resource Adequacy" and report their findings in their respective Area's "Triennial Review of Resource Adequacy." NPCC Areas currently measure Loss of Load Expectation (LOLE) when evaluating the resource adequacy of their systems. Table 1 provides a list of factors that affect interconnection assistance and how each Area has modeled them in their resource adequacy assessments.

While the amount of interconnection assistance that an Area receives from neighboring Areas will vary from hour to hour throughout the year, depending on its load, unit outages, etc., this study sought to determine an annual value of interconnection assistance which, if perfectly available for the entire year (in place of the actual interconnections with surrounding Areas) would enable the Area to maintain the same level of reliability, as measured in terms of daily Loss of Load Expectation (LOLE in days/year) as if the actual interconnections were present. This single MW value for an Area will be referred to as its **Annual Tie Benefit**. The **Annual Tie Benefit** includes both the non-firm emergency assistance into an Area and the net Area import from firm scheduled transactions between Areas.

[1] See: http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/B-08.pdf.

Table 1
NPCC AREA INTERCONNECTION ASSISTANCE MODELING

FACTOR		Québec	Maritimes	New England	New York	Ontario
1.	Capacity support from interconnection modeled	No	No	Yes	Yes	Yes
2.	Reliability Index Calculated in Area Resource Adequacy Studies	LOLE[1]	LOLE[2]	LOLE[2]	LOLE[2]	LOLE[2]
3.	Number of Areas/sub Areas modeled	1	3	4/13[3]	5/11[3]	4/10[3]
4.	Interconnections explicitly modeled	No	No	Yes	Yes	Yes
5.	Load forecast uncertainty represented	Yes	Yes	Yes	Yes	Yes
6.	Basis for installed reserve assumed for interconnected systems	N.A.	N.A.	Equal Risk	Equal Risk	Equal Risk
7.	Internal Area transmission modeled for resource adequacy assessments	No	Yes	Yes	Yes	Yes
8.	Interconnection outages modeled	No	No	Yes	No[4]	No
9.	Recently Approved NPCC Area Triennial Review of Resource Adequacy	11/02[5]	12/01[6]	11/02[7]	6/02[8]	7/03[9]

1 LOLE equal to 2.4 hours/year
2 LOLE equal to 0.1 days/year
3 GE's Multi-Area Reliability Simulation Program (MARS) used.
4 Outages modeled on cables into New York City and Long Island.
5 Interim Review of Québec Area Resource Adequacy conducted December 2003.
6 Interim Review of Maritimes Area Resource Adequacy conducted December 2003.
7 Interim Review of New England Area Resource Adequacy conducted October 2003.
8 Interim Review of New York Area Resource Adequacy conducted December 2003.
9 Interim Review of Ontario Area Resource Adequacy conducted June 2004.

Table 2 shows the interconnected Areas that are considered when each Area performs its reliability studies. The following table is read from left to right (e.g. the New York Area considers interconnections with the Québec, New England, Ontario and MAAC Areas)

Table 2
INTERCONNECTIONS CONSIDERED BY NPCC AREAS

Area Doing Study	Interconnections Considered in Area Studies						
	Québec	Maritimes	New England	New York	Ontario	ECAR	MAAC
Québec	-	-	-	-	-	-	-
Maritimes	-	-	-	-	-	-	-
New England	X	X	-	X	-	-	-
New York	X	-	X	-	X	-	X
Ontario[1]	X	-	-	X	-	X	-

[1] Ontario also models interconnections with Manitoba and Minnesota (MAPP).

3.0 MULTI-AREA RELIABILITY ANALYSIS

3.1 MULTI AREA RELIABILITY MODEL

(1) GE's MARS Program

General Electric's (GE) Multi-Area Reliability Simulation (MARS) Program [1] is a sequential Monte-Carlo simulator. It is capable of calculating on an Area and Sub-Area basis, the standard indices of daily Loss of Load Expectation (LOLE in days/year), hourly LOLE (hours/year) and a Loss of Energy Expectation (LOEE in MWh/year). In the CP-8 study, the model was used to determine daily LOLE for each of the NPCC Areas and Sub-Areas at the time of each NPCC Area's daily peak load.

In MARS, chronological system events are developed by combining randomly generated operating histories of the generating resources with inter-Area and intra-Area transfer limits and chronological hourly loads. The capacity margin is determined for each isolated Area at the time of its daily peak load. If an isolated Area has a negative capacity margin, the model seeks to initiate transfers from Areas with a positive capacity margin. Available reserves are allocated among deficient Areas by a priority list and among Sub-Areas on a shared basis in proportion to Sub-Area shortfalls. If a shortfall still exists after allocating the reserves that are available to flow across constrained interfaces, the model implements emergency operating procedures to avoid a loss of load to the extent possible. This process is repeated for each load forecast uncertainty level.

[1] See: http://www.gepower.com/prod_serv/products/utility_software/en/ge_mars.htm

3.2 MODELING ASSUMPTIONS

(1) Transfer Limits

Figure 1 (a) and Figure 1 (b) illustrate the Areas and transfer limits assumed for the years 2003 and 2006, respectively. Tie transfer limits between Areas are indicated with seasonal ratings as appropriate. Internal Area transmission constraints were represented in New York, New England, Ontario, and the Maritimes Areas, consistent with their respective modeling practices.

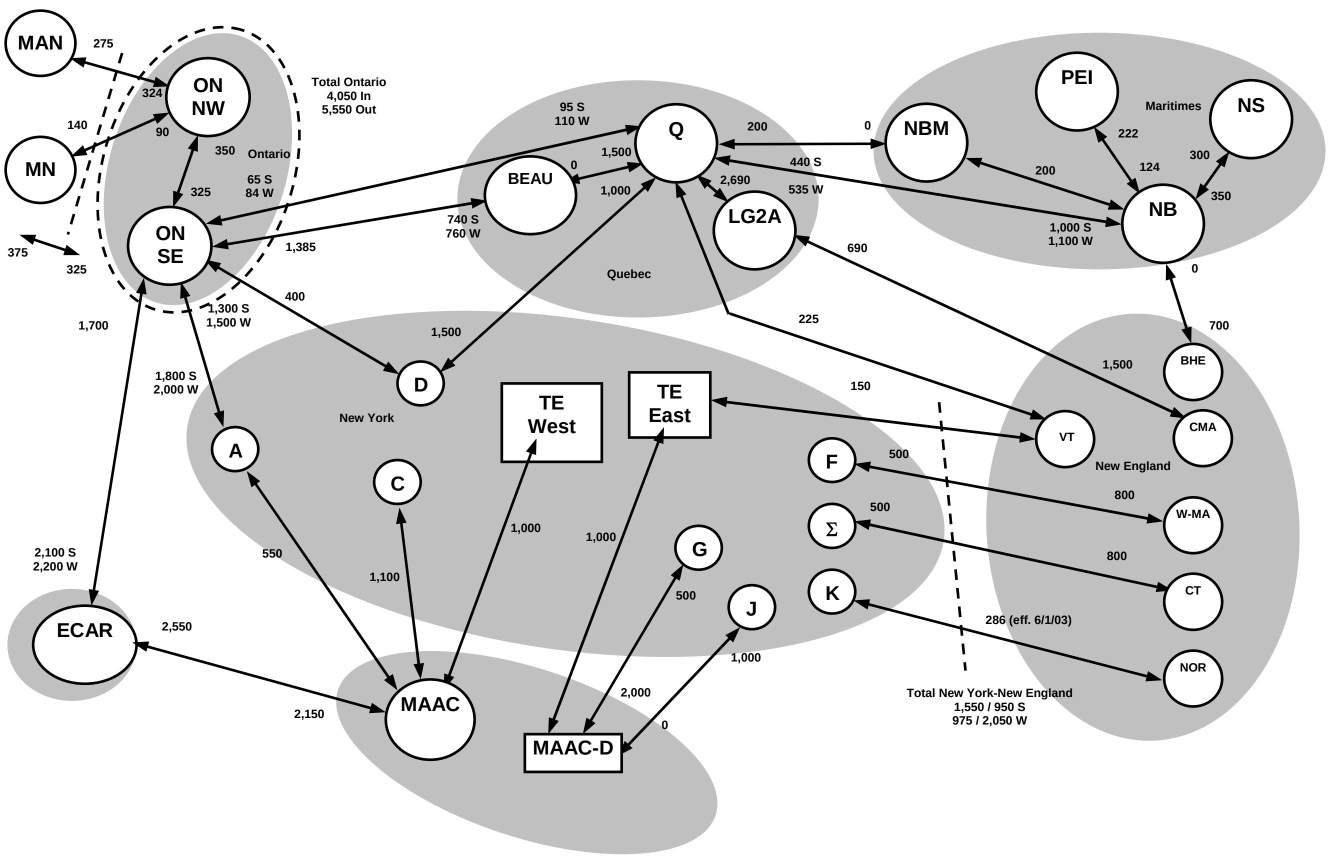

Figure 1 (a) Assumed NPCC Transfer Limits (MW) - 2003

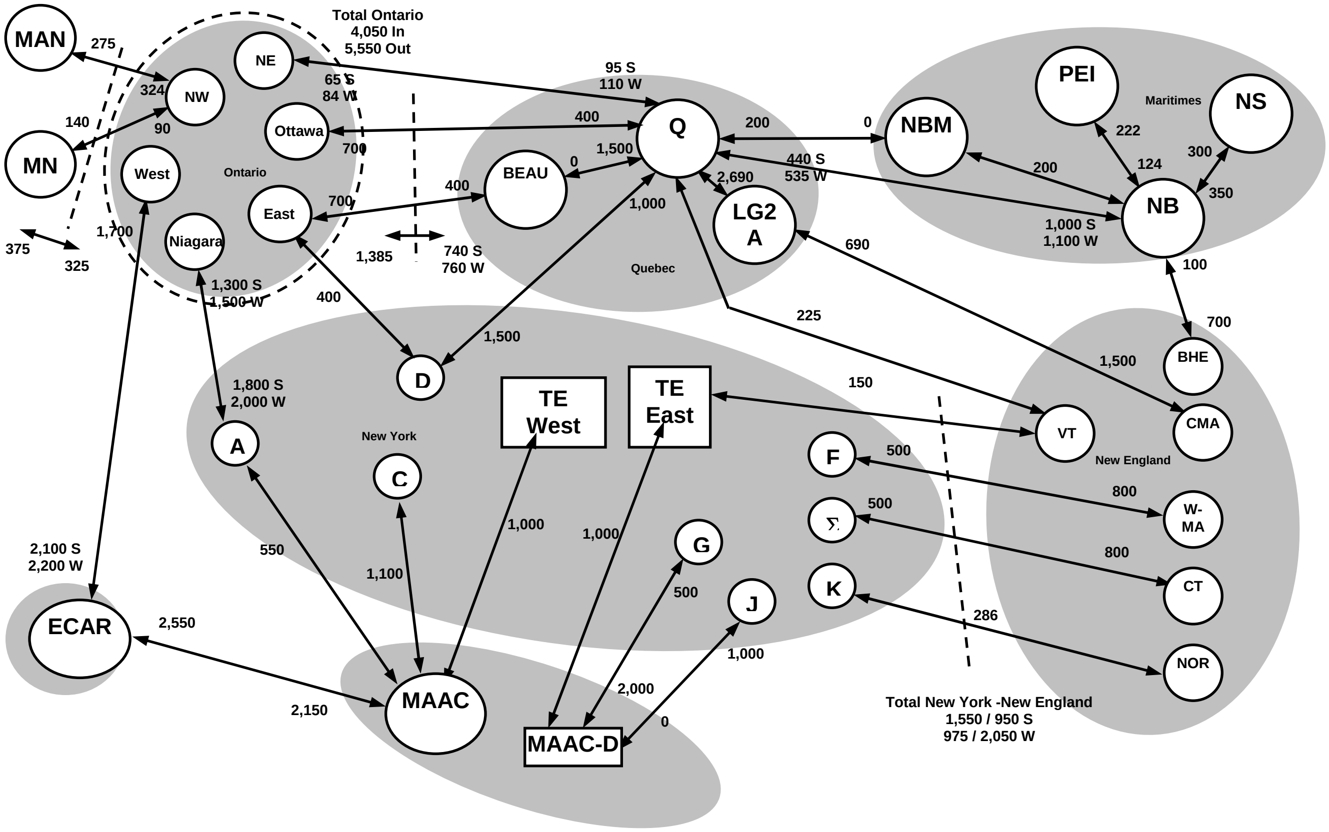

Figure 1 (b) Assumed NPCC Transfer Limits (MW) - 2006

The acronyms used in Figures 1(a) and 1(b) are defined as follows:

Q	- Québec	NS	- Nova Scotia
NB	- New Brunswick	PEI	- Prince Edward Island
NE	- Northeast zone	NBM	- Millbank
NW	- Northwest zone	BEAU	- Beauharnois
ON-SE	- Ontario - Southeast	BHE	- Bangor Hydro Electric
ON-NW	- Ontario - Northwest	NOR	- Norwalk-Stamford
MAN	- Manitoba	W MA	- Western Massachusetts
MN	- Minnesota	VT	- Vermont
CT	- Connecticut	C MA	- Central Massachusetts
LG2A	- La Grande 2A Station		
ECAR	- East Central Area Reliability Council		
MAAC	- Mid-Atlantic Area Council		

Transfer Limits have Annual Ratings unless noted:

S – Summer Rating
W – Winter Rating

(2) Load Model

After reviewing the weather characteristics of the years from 1988 through 1997, the previous NPCC CP-5 Working Group's "Review of Interconnection Assistance Reliability Benefits" study [1] used 1995 as the model for the load shape. Upon reviewing the weather characteristics of the years 1989 through 2002, the NPCC's Task Force on Coordination of Planning directed the CP-8 Working Group to continue to use 1995 as the model for the load shape and use the growth rate in each month's peak to escalate their Area's loads to match their year 2003 and 2006 forecasts. Figures 2 (a) and 2 (b) shows the resulting diversity in load shapes between the NPCC Areas forecast for the years 2003 and 2006, respectively. Although Ontario is officially winter peaking under current normal weather assumptions, a transition to summer peaking is expected to occur in 2005. Under extreme weather conditions, Ontario is already summer peaking. Normal weather summer and winter peaks are very close in magnitude, effectively making Ontario dual-peaking. The other Canadian Areas are winter peaking while the US Areas are summer peaking. This seasonal difference in the annual peak load contributes to the interconnection assistance available to each Area.

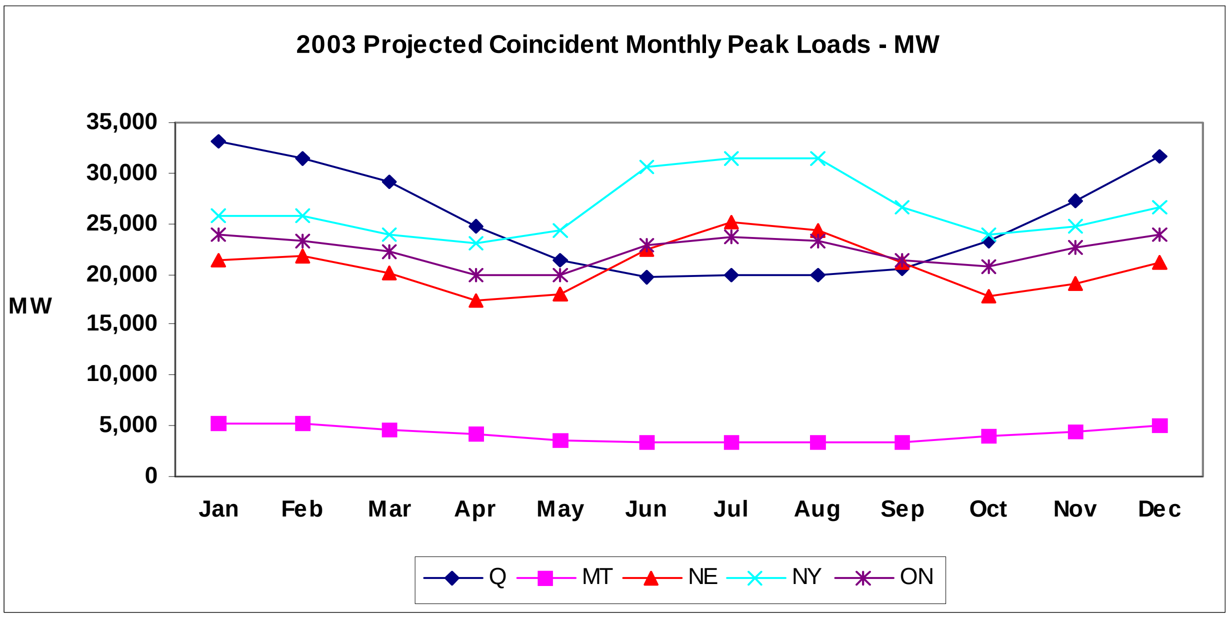

Figure 2 (a) - 2003 Forecast Monthly Peak Loads for NPCC Areas

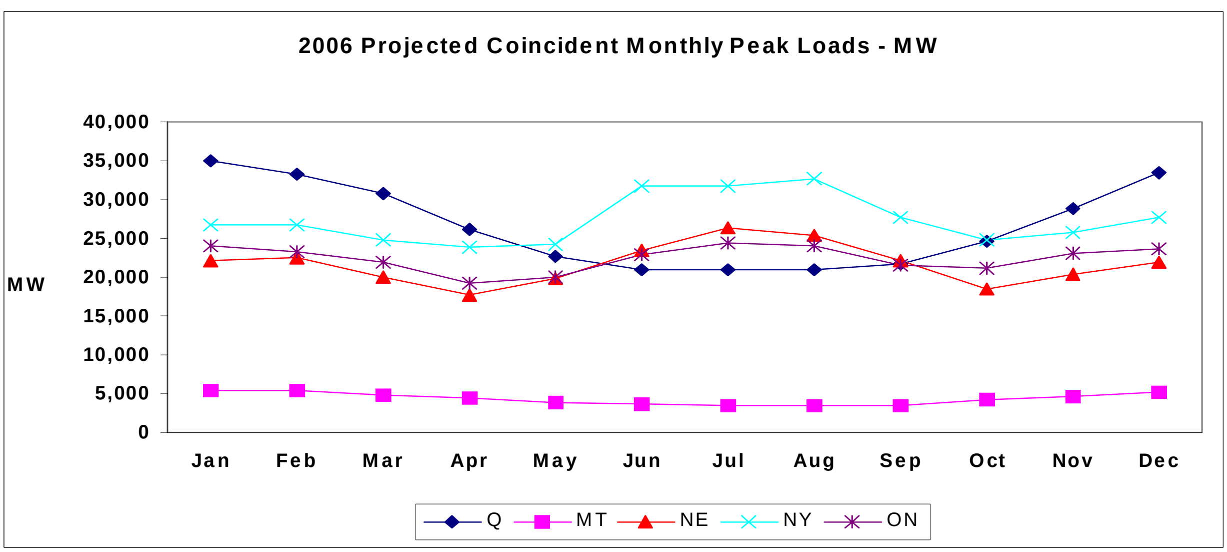

Figure 2 (b) - 2006 Forecast Monthly Peak Loads for NPCC Areas

[1] Review of Interconnection Assistance Reliability Benefits, NPCC, May 12, 1999.

(3) Generation Resources

Each Area provided its projections of "As Is" available resources consistent with their forecasts for the years 2003 (Table 3(a)) and 2006 (Table 3(b)), as of September 2003. Firm purchases and sales were modeled as a shift in resources from the selling Area to the buying Area.

Table 3 (a)
NPCC Capacity and Load Assumptions for July 2003 - MW
"As Is"

	Q [1]	MT	NE	NY	ON [2]
Assumed Capacity	24,893	6,297	30,127	36,442	28,045
Purchase/Sale	2,534	-850	997	742	0
Peak Load	19,865	3,286	25,120	31,430	23,677
Reserve (%)	38	66	24	18	18
Scheduled Maintenance	(1)	1,011	93	268	32

Table 3 (b)
NPCC Capacity and Load Assumptions for July 2006 - MW
"As Is"

	Q [1]	MT	NE	NY	ON [2]
Assumed Capacity	25,003	6,209	31,075	42,105	30,348
Purchase/Sale	4,194	-200	352	-258	0
Peak Load	20,986	3,498	26,294	31,798	24,491
Reserve (%)	39	72	20	32	24
Scheduled Maintenance	(1)	585	0	361	1,152

(4) Transition Rates

The MARS program uses transition rates to represent the random forced outages of thermal units. Most of the unit data was represented with two-state transition rates, where units are represented as being fully available or as on full forced outage. The Maritimes and New York Areas also modeled units with partial outage states. Partial outage rates represent a unit as fully available, as on full forced outage, and with partially available state(s).

[1] Capacity shown for Québec adjusted for scheduled maintenance.
[2] Capacity shown for Ontario represents net installed, Base Case assumes Bruce A and Pickering Units out of service; Peak load shown based on the 1995 load shape.

(5) Assistance Priority

Table 4 indicates the priority order followed when allocating reserves and operational assistance to Areas with a deficiency.

Table 4
PRIORITY ORDER MODELED

	Priority of Assistance		
Area Providing Assistance	**1ST**	**2ND**	**3RD**
Québec	MT ON	NE NY	-
Maritimes	Q ON	NE NY	-
New England	NY	Q MT ON	-
New York	NE	Q MT ON	-
Ontario	Q MT	NE NY	-
Millbank Units	Q	MT	-
LG2A Units	Q	NE	MT ON
ECAR	ON	MAAC	-

Areas listed with equal priority received assistance on a shared basis in proportion to their deficiency. The Millbank Station, although located within the Maritimes, has two of its units contracted to Québec. These units are modeled as a resource for Québec first, to reflect their priority order of assistance. It was assumed that MAAC assists everyone with equal priority.

(6) Operating Procedure Assumptions

Table 5 indicates the amount of load relief assumed available from operating procedures for each NPCC Area. Each step was initiated simultaneously in all NPCC Areas and Sub-Areas. The amount of Area Interconnection Assistance was calculated following the utilization of these amounts.

Table 5
NPCC Operating Procedures Assumptions
(MW)

Actions	Q	MT	NE	NY	ON
1. Curtail Load / Utility Surplus	0	0	244	0	450
LRP/SCR/EDRP	0	0	0	885	0
Manual Voltage Reduction	0	0	0	0.26% of load	0
2. No 30-min Reserves	500	229	566	600	441
3. Voltage Reduction or Interruptible Loads *	300	587	1.3 % of load	1.56% of load	580
4. No 10-min Reserves	1,000	300	962	0	1,139
General Public Appeals	0	0	0	347	0
5. General Public Appeals	0	0	0	-	200
No 10-min Reserves	-	-	-	1,200	-

* Interruptible Loads for Maritimes (implemented only for the Area), Voltage Reduction for all others

(7) Load Forecast Uncertainty

Table 6 shows the uncertainty of the annual peak load forecast modeled. The effects on reliability of uncertainties in the peak load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence. While the per unit variations in the load can vary on a monthly basis, Table 6 shows the values assumed for July, 2003 corresponding to the occurrence of the NPCC system peak load. Table 6 also shows the probability of occurrence assumed for the entire year for each of the seven load levels modeled.

In computing the reliability indices, all of the Areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the uncertainty affect all of the Areas at the same time. The amount of the effect can vary according to the variations in the load levels.

Table 6
Per Unit Variation in Load Assumed for the Month of July 2003

Area	Per-Unit Variation in Load						
Q	1.0679	1.0679	1.0340	1.0000	0.9660	0.9321	0.9321
MT	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE	1.0954	1.0565	1.0281	1.0000	0.9719	0.9435	0.9046
NY	1.0584	1.0499	1.0250	1.0000	0.9770	0.9660	0.9070
ON	1.1468	1.0978	1.0490	1.0000	0.9510	0.9022	0.8532
Prob.	0.0062	0.0606	0.2417	0.3830	0.2417	0.0606	0.0062

3.3 METHODOLOGY

The Tie Benefits Methodology used in this Review involved determining the amount of load increase that an interconnected Area can accommodate while maintaining a given level of reliability. The specific Steps are summarized below:

Step 1 – Isolate the "As Is" [1] Areas after scheduling firm contracts and removing any internal transmission constraints. Bring each isolated Area to be approximately "At Criteria" [2] (0.1 days/year LOLE) by adjusting the hourly loads in each Area proportionally across all sub-Areas.

Step 2 – Interconnect the Areas and restore internal transmission constraints in all Areas except for the Area of interest. Starting with the "As Is" loads in each Area, increase the sub-Area loads proportionately in the Area of interest until it returns to the LOLE calculated in Step 1 (approximately 0.1 days/year).

Step 3 – Isolate the Areas after scheduling firm contracts and removing the internal transmission constraints. Add a given amount of "perfect" capacity [1] to each Area for the entire year until the Area LOLE returns to the LOLE calculated in Step 2 (approximately 0.1 days/year). The amount of perfect capacity added is the maximum amount of tie benefit available for each Area, excluding any firm contracts, assuming "As Is" loads for neighboring Areas.

While increasing the sub-Area loads proportionately is a good approach in estimating the amount of load increase that an Area can accommodate through its interconnections with neighboring Areas, the presence of internal transmission constraints within an Area can limit the amount of load increase possible in the constrained sub-Areas, and consequently in the Area as a whole. For this reason, the methodology employed in this study ignores the internal transmission constraints in an Area when adjusting the sub-Area loads to determine the amount of assistance

[1] The "As-Is" assumption refers to the modeling of systems with resources that are expected to be in-place for the years 2003 or 2006, as supplied by the CP-8 Working Group in September 2003.
[2] The "At Criterion" assumption refers to modeling the adequacy condition of each of the NPCC Areas being at a criterion level of 0.1 days/year LOLE.

(non-coincident) that the other Areas can provide (Step 2). In order to provide a valid comparison with the results of Step 2, the internal constraints were also ignored in Step 1 as the loads in each Area were adjusted to bring each isolated Area to criterion. This approach thus provides an estimate of the amount of assistance (non-coincident) that's available, regardless of whether or not an Area can make use of all of it due to internal constraints.

In Step 2, the Areas were then interconnected and their sub-Area loads adjusted, one Area at a time, until the Area of interest returned to the LOLE of the previous step. During this part of the process, the internal constraints were ignored in the Area of interest, but the internal constraints in all of the other Areas were respected in case there was bottled generation that would limit the amount of assistance that an Area could provide. This provided an estimate of the amount by which each Area's peak load can be increased when interconnected with the other Areas.

In Step 3, the Areas were isolated again, this time using the adjusted peak loads of the previous step, with the interconnections replaced with fixed capacity. This step converts the "expected peak load" value of the interconnections into an annual fixed capacity amount. In some cases the fixed capacity was greater than the increase in the expected peak load, and in some cases it was less. Two factors impact the conversion from expected peak load increase to fixed capacity.

The first involves the fact that the loads were not being increased by a fixed MW amount, but rather on a percentage basis. For instance, if the peak load was increased by 1,000 MW, then it will amount to an increase of 900 MW in an hour for which the original load was 90% of the peak. The fixed capacity, however, is a fixed MW amount for the entire year. Consequently, 1,000 MW of additional perfect capacity representing the outside tie assistance would be expected to more than offset an 1,000 MW increase in peak load, and that the equivalent fixed capacity amount would actually be less than the increase in the expected peak load. This would always be true in the absence of load forecast uncertainty, which leads to the second factor.

With load forecast uncertainty, a given MW increase in the expected peak load would actually result in a larger MW increase at the higher load forecast uncertainty load levels, which is where most of the risk occurs. As a result, the tie assistance from the outside as represented by the fixed capacity amount would have to be greater than the expected peak load increase in order to maintain the same LOLE. This results in two forces working in opposite

[1] "Perfect" capacity assumes 100% availability.

directions, and depending on the Area's load shape and load forecast uncertainty multipliers, one will predominate over the other.

The above methodology was used for both the years 2003 and 2006 and provided an estimate of the **Annual Tie Benefit**, assuming the “As Is” loads in each of the Areas providing assistance. Since it is optimistic for an Area to plan its system assuming that the neighboring systems are much more reliable than is required by the NPCC criteria, the methodology was refined by adding the following steps:

> **Step 4** - Bring each Area of the interconnected “As Is” system, with internal transmission constraints, to approximately 0.1 days/year LOLE by adjusting the hourly loads in each Area proportionally across all sub-Areas.
>
> **Step 5** - Remove the internal transmission constraints in the Area of interest and increase its sub-Area loads proportionally until it returns to the LOLE in Step 4; loads in the other Areas as adjusted in Step 4.
>
> **Step 6 –** Isolate the Areas after scheduling firm contracts and removing internal transmission constraints. Add a given amount of “perfect” capacity to each Area for the entire year until the Area LOLE returns to 0.1 days/year.

These additional Steps, which were applied to the year 2006 only, were intended to provide an estimate of the amount of assistance that would be available if each Area just met criterion.

3.4 RESULTS

The results of the detailed methodology are shown in Table 7 (a) for the year 2003 and Table 7 (b) for the year 2006 in the column labeled **Annual Tie Benefit**. Also shown in those Tables are the **Maximum Net Import** for each Area that were calculated for the “As Is” system and for the system in which the Area loads were adjusted to bring each Area to approximately 0.1 days/year LOLE interconnected. The **Maximum Net Import** for an Area is the largest value of net simultaneous flow into an Area that was calculated throughout the simulation process. As such, it would be a function of the reliability of the Area receiving assistance as well as the reliability of the Areas providing the assistance, combined with the total transfer capability into the receiving Area.

While the **Maximum Net Import** gives an indication of the maximum amount of assistance that an Area receives assuming “As Is” or “At Criteria” loads, it will be less than the **Annual Tie Benefit** depending on the extent to which the Area is deficient; a highly reliable Area will not need much assistance, although the other Areas may have much to offer. Internal transmission constraints were also modeled in both these cases, further limiting the amount of assistance available to an Area.

The results indicate that the **Annual Tie Benefit** for an Area, as computed with the detailed methodology, is nearly equal to the total transfer capability into the Area. This is not surprising given the high reliability in the "As Is" system. These results provide an estimate of the amount of assistance that's available, regardless of whether or not an Area can make use of it due to its internal constraints.

For the Québec, the Maritimes, and the Ontario Areas, the **"As Is" Maximum Net Import** shown in Table 7 is quite close to the **Annual Tie Benefit** that was calculated through the detailed methodology. For those Areas in which internal transfer limits appear to be more of an issue (New England and New York), the **"As Is" Maximum Net Import** understates the **Annual Tie Benefit**.

The drop in the **"As Is" Maximum Net Import** for New England and New York going from the year 2003 to 2006 appears to be related to the improved reliability of those Areas in 2006 and thus less of a need for outside assistance.

Also included in Table 7 is the **"At Criteria" Maximum Net Import** for the cases in which all of the Areas were brought to 0.1 days/year LOLE together, while still maintaining all of the internal constraints. For the three areas that were already importing close to their tie limits (Québec, the Maritimes, and the Ontario Areas), the values did not change much, increasing slightly in response to their increased loads. For New England and New York, increasing the loads to bring the Areas to an LOLE of 0.1 days/year increased their maximum net imports, but the internal constraints limited the amount by which the sub-Area loads could be raised before exceeding the 0.1 days/year LOLE.

As a result, the **"At Criteria" Maximum Net Imports** for those two Areas indicate the amount of outside assistance that they could make use of rather than the amount that was actually available to them.

Table 7 (a)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2003
(MW)

Area	"As Is" Maximum Net Import	"At Criteria" Maximum Net Import	Annual Tie Benefit	Total Import Capability at Time of Area Peak
Q	3,442	3,452	**3,445**	3,520
MT	1,091	1,100	**1,092**	1,100
NE	1,035	1,207	**3,972**	3,975
NY	3,089	5,230	**6,675**	7,300
ON	4,050	4,050	**4,050**	4,050

Table 7 (b)
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2006
(MW)

Area	"As Is" Maximum Net Import	"At Criteria" Maximum Net Import	Annual Tie Benefit	Total Import Capability at Time of Area Peak
Q	3,300	3,333	**3,380**	3,520
MT	1,200	1,200	**1,200**	1,200
NE	407	1,271	**3,975**	3,975
NY	81	5,497	**7,150**	7,300
ON [1]	4,050	4,050	**4,050**	4,050

While the **Maximum Net Import** seems to be a good approximation to the **Annual Tie Benefit** in the absence of significant internal constraints, an approach in which the internal constraints are removed from one Area at a time is necessary to determine the **Annual Tie Benefit** available to Areas with binding internal constraints.

The refined methodology (Steps 4-6) was applied to the year 2006, in which the Maximum Tie Benefit Potential was computed assuming that the Areas providing assistance were at approximately 0.1 days/year LOLE. These results

[1] Maximum net imports of 4,745 MW ("As is") and 4,923 MW ("At criteria") ignoring Ontario external Tie Line constraints.

are shown in Table 8; the "As Is' results from Table 7(b) are also included for comparison. These results are intended to provide an estimate of the amount of assistance that would be available if each Area just met the criterion.

Also shown in Table 8 is the **"At Criteria" Annual Tie Benefit** calculated by not removing the internal Area transmission constraints in Steps 1 - 3. This provides an estimate of the assistance available for import into each Area under these assumptions.

For the Maritimes, New England and Ontario Areas, the **"At Criteria" Annual Tie Benefit** is nearly equal to the **"As Is" Annual Tie Benefit**, both of which are close to the actual Area import limits. For these Areas, the **Annual Tie Benefit** is more limited by their ability to import the assistance than it is by the ability of the other Areas to assist.

The larger difference between the **"As Is" and "At Criteria" Annual Tie Benefit for** Québec and New York indicate the extent to which these Areas, with more than adequate import capabilities, could rely extensively on assistance from their neighbors.

Table 8
ANNUAL INTERCONNECTION ASSISTANCE ESTIMATED FOR 2006 - MW

	With Internal Constraints	Without Internal Constraints	Without Internal Constraints
Area	**"At Criteria" Annual Tie Benefit**	**"At criteria" Annual Tie Benefit**	**"As Is" Annual Tie Benefit**
Q	2,720	2,820	3,380
MT	930	1,200	1,200
NE	487	3,912	3,975
NY	3,775	5,488	7,150
ON	3,150	4,008	4,050

3.5 COMPARISON OF AREA INTERCONNECTION ASSISTANCE

Table 9 shows the interconnection assistance assumed in recent Area studies and the results from this Review. When interpreting these results, there are two important points that are critical to recognize; first, the data used in recent Area studies may have been considerably different from that used in these studies, and second, the underlying methodology varies for each NPCC Area. Additional information follows for the three NPCC Areas (New England, New York, and Ontario) that assume interconnection assistance in their resource adequacy assessments.

Table 9
COMPARISON OF ASSUMED AND ESTIMATED ANNUAL INTERCONNECTION ASSISTANCE - MW

NPCC Area	Assistance Reported in Recent Area Studies (MW)	Range of Estimated Annual Tie Benefit CP-8 Study Results for 2006 (MW)
Québec	0 [1]	2,720 - 3,380
Maritimes	0 [2]	930 - 1,200
New England	1,800 [3]	487 - 3,975
New York	2,100 [4]	3,775 - 7,150
Ontario	1,500 [5]	3,150 - 4,050

New England

The results of a recent tie reliability benefits study [6] by the Independent System Operator of New England (ISO-NE) indicated that the amount of tie reliability benefits New England can receive from its interconnections can be influenced by a number of factors. These factors include internal transmission constraints within New England, load diversity (load correlation) between New England and its neighbors and the technique used to for bringing a given Control Area to the resource planning reliability criterion when sub-Areas are involved. The results of their study showed that the amount available can be as low as 30 MW (when all transmission constraints in New England are modeled) and as high as 3,300 MW (when all transmission constrains are removed).

In setting the NEPOOL Installed Capacity Requirement for the 2004 – 2005 Power Year [7], NEPOOL assumed Tie Reliability Benefits of 600 MW from New York and 200 MW from New Brunswick, with a monthly Hydro-Québec

[1] NPCC Triennial Review of Québec Area Resource Adequacy, November 2002.
[2] NPCC Triennial Review of Maritimes Area Resource Adequacy, December 2001.
[3] NPCC Triennial Review of New England Area Resource Adequacy, November 2002.
[4] NPCC Triennial Review of New York Area Resource Adequacy, June 2002.
[5] NPCC Triennial Review of Ontario Area Resource Adequacy, July 2003.
[6] "NEPOOL Tie Reliability Benefits Study", ISO-NE, December 3, 2002. See: http://www.iso-ne.com/Historical_Data/periodic_reports/objective_capability_review/NEPOOL_Tie_Reliability_Benefits_Study_Revised.doc
[7] "ISO New England Report on the NEPOOL Installed Capacity Requirement For the 2004 – 2005 Power Year", ISO-NE, May 20, 2004.
See: http://www.iso-ne.com/Historical_Data/periodic_reports/objective_capability_review/Review%20of%20NEPOOL%20ICAP%20Requirement%20for%20Power%20Year%202004-2005%20-%20FINAL.pdf

Interconnection Capacity Credit ranging from 200 MW to 1,200 MW. Hydro-Québec Interconnection Capacity Credits for the 2004 – 2005 Power Year were developed to comply with an August 15, 2003 FERC Order. [1]

New York

The New York State Reliability Council established the annual statewide installed reserve margin for the New York Control Area for the May 2004 through April 2005 period at 18 percent [2]. This equates to an Installed Capacity Requirement of 1.18 times the forecasted New York Control Area 2004 peak load. Based on this study, the New York ISO determined the locational installed capacity requirements for the New York Control Area for the 2004 – 2005 Capability Year beginning May 1, 2004 [3].

These studies assumed a total of 227 MW of firm purchases from PJM, New England, and Ontario, and an additional 1,200 MW from Hydro-Québec, 345 MW from New England and 983 MW from PJM. The New England to Long Island (Cross Sound Cable) tie line is modeled with a 305 MW firm purchase. This results in 3,060 MW of expected summer external installed capacity (2,755 MW without the Cross Sound Cable tie line). Assuming such arrangements permits the New York Control Area installed reserve margin to be 6.4 percentage points lower than otherwise required.

Ontario

The Independent Electricity Market Operator for Ontario has reported in its 18-Month Outlook [4] that the actual hourly import levels experienced from market opening in May 2002 up to February 24, 2004 indicated an average import level of 1,164 MW for all hours. During the 3,044 hours when Ontario demand exceeded 20,000 MW the average import level was 1,544 MW. During the 338 hours when Ontario demand exceeded 23,000 MW the average import level was 2,293 MW, and occasionally reached the Ontario coincident import capability of approximately 4,000 MW.

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[1] See: http://www.iso-ne.com/FERC/orders/ER03_894_000_and_ER03-894_001.pdf

[2] "New York Control Area Installed Capacity Requirements For The Period May 2004 Through April 2005" See: http://www.nysrc.org/pdf/Doucments/Report12-12-03final.pdf

[3] "Locational Installed Capacity Requirements Study Covering The New York Control Area For the 2004 – 2005 Capability Year" See: http://www.nyiso.com/services/documents/studies/pdf/locational_installed_cap_require_04_05.pdf

[4] "18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System From April 2004 to September 2005" See: http://www.theimo.com/imoweb/pubs/marketReports/18MonthOutlook_2004mar.pdf

4.0 CONCLUSIONS

The CP-8 Working Group concluded that:

- the methodology and assumptions used in this Review was consistently applied to all NPCC Areas, using the same multi-Area reliability model;
- NPCC Area estimates of interconnection benefits used to meet the NPCC Resource Reliability Criterion were reviewed on a consistent basis; and,
- the interconnection assistance values reported by NPCC Areas in their recent resource adequacy assessments appear to be reasonable and do not overstate interconnection benefits.

5.0 OBSERVATIONS

Several major transmission projects have been announced[1], in varying stages of the planning process, for the 2005-06 time period, including (but not limited to):

- **The Neptune Project** [2] - proposal involves the installation of two parallel submarine transmission cables from Newbridge, Long Island, NY to Sayerville, NJ - the 600 MW project recently received unanimous approval by the New York State PSC;

- **The TransEnergie Harbor Cable Project** [3] – proposal consists of a HVDC transmission system (total bi-directional transfer capability up to 650 MW), including buried underwater submarine cables in New York Harbor from Linden, NJ to Queens, NY;

- **Ontario – Québec Tie** [4] **-** Hydro One with TransÉnergie, the transmission division of Hydro-Québec, proposed a new 1,250 MW interconnection between the two provinces. A new double circuit 230 kV line linking Hawthorne TS in Ontario to transmission facilities in Outaouais, Québec is currently planned. Ontario approvals are in place. Discussions involving Ontario and Québec governments and representatives from Hydro One and TransÉnergie regarding this project are ongoing.

- **Second New Brunswick Tie** [5]**-** New Brunswick Power's proposal to build a second tie line to New England to carry up to 1,000 MW (total) between the province and the State of Maine;

- **Empire Connection** [6] - proposal to develop two HVDC transmission lines (one from Green County to Bronx County, NY and one from Albany County to Bronx County, NY) along the NY State Thruway Amtrak/Metro North rights-of-way;

- **The Lake Erie Link Transmission Project** [7] - a high-voltage HVDC transmission system, including buried underwater cables under Lake Erie (anticipated bi-directional transfer capability of up to a maximum of 975 MW), connecting the control Areas of Ontario with the PJM Interconnection; and,

- **The Niagara Reinforcement Project** [1] - this project, by Pegasus Power Systems, proposes to improve reliability and reduce congestion in the New York, New England and PJM. A proposed +/- 500 kV HVDC

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[1] NPCC Major Project List, April 12, 2004 See: https://www.npcc.org/Member/SecuredFiles/Documents/MajorProjectLists/currentYear/Major-Project-List%204-12-2004.pdf

[2] See: http://www.neptunerts.com/.

[3] See: http://www.transenergieus.com/projects.htm.

[4] See: http://www.hydroonenetworks.com/en/about/10_yr_transmission_plan_overview.pdf.

[5] "RTEP03 Executive Summary and Overview" See: http://www.iso-ne.com/smd/transmission_planning/Regional_Transmission_Expansion_Plan/.

[6] See: http://www.empireconnection.com/.

[7] See: http://www.lakeerielink.com/.

transmission system will act as a "back-bone" for the region by stabilizing, reinforcing and benefiting each of the surrounding networks. The system is expected to go into commercial operation in the spring or summer of 2008.

In addition, the Federal Energy Regulatory Commission (FERC) has issued an Order [2] delaying implementation of ISO-NE's proposed Locational Installed Capacity (LICAP) proposal.[3] until January 1, 2006. Furthermore, ISO-NE has also been directed to submit a report every 90 days (beginning 90 days from the date of the Order) updating the progress made in the siting, permitting and construction of transmission and generation upgrades within the New England Control Area.

ISO-NE's 2003 Regional Transmission Expansion Plan [4] identified nearly 250 regulated transmission projects throughout New England, some "planned" (receiving NEPOOL Section 18.4 approval), some proposed (some analytical study work completed), and some in the early stages of development. The study concluded that the Southwest Connecticut region remains ISO-NE's number one area of immediate concern and that reliability also remains a critical issue in Northwest Vermont because of a lack of power plants in the area and weak transmission links. As there have been no announced market responses that would significantly mitigate the concerns for these areas, ISO-NE continues to support the Southwest Connecticut Reliability Project and the Northwest Vermont Reliability Project.

The IMO's 2004 10-Year Outlook [5] notes that a significant amount of additional supply and demand response is needed in Ontario, in order to maintain long-term adequacy and to replace the coal-fired generation. The 10-Year Outlook also highlights the need for transmission reinforcements, particularly in the Greater Toronto Area. Hydro One has prepared a summary of transmission solutions [6] planned for the next ten years.

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[1] See: http://www.teshmont.com/news.htm.

[2] FERC Order on Compliance Filing and Establishing Hearing Procedures – LICAP Order Docket Nos. ER03-563-030 and EL04-102-000, issued June 2, 2004. See: http://www.iso-ne.com/FERC/orders/ER03-563-030_6-2-04.pdf

[3] On March 1, 2004, ISO-NE submitted a FERC filing in compliance with the Commission's directive in Devon Power LLC, et al that a locational installed capacity (LICAP) or deliverability requirements be implemented in New England by June 1, 2004. See: http://www.iso-ne.com/FERC/filings/Other_ISO/LICAP_Filing.pdf

[4] "RTEP03 Executive Summary and Overview" See: http://www.iso-ne.com/smd/transmission_planning/Regional_Transmission_Expansion_Plan/.

[5] "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2005 to December 2014" See: http://www.theimo.com/imoweb/pubs/marketReports/10YearOutlook_2004mar.pdf.

[6] "A 10 Year Transmission Plan for the Province of Ontario 2004-2013" See: http://www.hydroonenetworks.com/en/about/10_yr_transmission_plan_detail.pdf.

6.0 RECOMMENDATIONS

In light of these and other developments, the CP-8 Working Group recommends that NPCC's Review of Interconnection Assistance Reliability Benefits be updated once these developments (or their combination) are further quantified in order to identify the impact on the NPCC Area interconnection assistance estimated for the 2006 time frame.