NPCC, Inc.

Review of Interconnection Assistance Reliability Benefits

June 1, 2011

NPCC CP-8
Working Group

NORTHEAST POWER COORDINATING COUNCIL, Inc.

CP-8 WORKING GROUP

REVIEW OF INTERCONNECTION ASSISTANCE RELIABILITY BENEFITS

Approved by the RCC

June 1, 2011

FOREWORD

Annual tie benefits are a measure of the expected amount of emergency assistance each Balancing Authority could obtain from the interconnected system under certain assumed system conditions. Annual tie benefits mainly result from load diversity and the randomness of resource outages among all the areas being modeled in the study. Annual tie benefits are calculated from a resource adequacy planning standpoint and through a probabilistic analysis, which takes into consideration the uncertainty of the load forecasts, randomness of resource outage patterns, representative transmission limitations internal to each region and between different regions, and load relief available from all emergency operating procedures, taken in a prescribed order.

This analysis, by definition, cannot reflect the combination of operational constraints that may occur in a particular real-time instance. The model assumes in the event that some areas are in need of help, the resources that are not on forced outage in other areas are ready to produce their full output to provide assistance, while in actual operations they may not be even committed, or their outputs are substantially lower than their ratings due to start-up time and ramping limitation.

The transmission transfer capabilities assumed in this analysis represent typical emergency limits; in actual operations these limits may have been further reduced to respect multiple contingencies.

This analysis also assumes that the emergency assistance can flow unconstrained and instantaneously from any surplus areas to any needed areas within the interconnected system, while in actual operations the arrangement of emergency assistance from one area to another may involve substantial effort and time for coordination and resource re-dispatch, and may be limited by differences in operational protocols in each area and reserve sharing agreements in place between different areas.

The values presented in this analysis should be considered as a potential amount of annual tie benefits from a resource adequacy planning perspective; it is recognized that the actual amount of tie line assistance available in real time operations can vary due to the actual system conditions and operational constraints at the time.

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 the 2011 – 2015 time period;
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 Benefits for a hypothetically "At Criteria" and "As Is" year 2011 and year 2015 system representation. GE International, Inc. 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.

Table EX – 1
Comparison of Assumed and Estimated
Annual Interconnection Assistance – MW

NPCC Area (Year of Review)	**Assistance Reported in Recent NPCC Review of Resource Adequacy**	2011 Net Firm Area Imports at Time of Peak	**Range of Estimated Annual Tie Benefit Potential for 2011**	2015 Net Firm Area Imports at Time of Peak	**Range of Estimated Annual Tie Benefit Potential for 2015**
Québec (2008)	0	504	3,409 – 4,004	847	2,892 – 3,747
Maritimes (2010)	0	-200	1,076 - 1,353	0	1,252 – 1,536
New England (2008)	1,800	1,111	3,246 – 4,251	284	2,709 – 4,244
New York (2009)	1,861[1]	1,888	4,393 – 8,538	1,888	5,088 – 7,788
Ontario (2009)	0	0	2,660 – 4,800	0	3,690 – 4,990

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. In this review, the **Annual Tie Benefit Potential** shown in Table EX-1 includes both the non-firm emergency assistance into an Area and the net Area import from firm scheduled transactions between Areas.

[1] New York's 2009 Comprehensive NPCC Resource Adequacy Review was based on the New York Control Area Capacity Requirements for the Period May 2009 through April 2010 - See: http://www.nysrc.org/pdf/Reports/2009%20IRM%20Report%20-%20Final%2012%2005%2008%20V1.pdf.

After consistently applying the methodology and assumptions used in this Review to all NPCC Areas, using the same multi-Area reliability model, based on the NPCC 2010 Long Range Adequacy Overview,[2] 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.

[2] See: http://www.npcc.org/viewDoc.aspx?name=ApprovedtLongRangeOverview_Nov_30_.pdf .

CP-8 WORKING GROUP

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The members of NPCC's CP-8 Working Group wish to acknowledge the contributions of Messrs. Glenn E. Haringa, GE International, Inc., and Andy Ford, the PJM Interconnection.

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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 (2011) and the near term (2015 time 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 Regional Reliability Reference Directory No. 1 - Design and Operation of the Bulk Power System [3], Section 5.2 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 International, Inc. 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, based on the NPCC 2010 Long Range Adequacy Overview,[4] to develop a model suitable for the 2011 and 2015 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 load forecast uncertainties and emergency operating procedures were modeled on a consistent basis.

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 Regional Reliability Reference Directory No. 1 - Appendix D [3], "Guidelines for Area Review of Resource Adequacy" and report their findings in their respective Area's "Comprehensive 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

[3] See: http://www.npcc.org/viewDoc.aspx?name=Directory+1+-+

[4] See; http://www.npcc.org/viewDoc.aspx?name=ApprovedtLongRangeOverview_Nov_30_.pdf.

interconnection assistance and how each Area has modeled them in their respective NPCC Comprehensive Resource Adequacy Reviews.

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 Potential**. In this review, the **Annual Tie Benefit Potential** includes both the non-firm emergency assistance into an Area and the net Area import from firm scheduled transactions between Areas.

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	No
2.	Reliability Index Calculated in Area Resource Adequacy Studies [a]	LOLE	LOLE	LOLE	LOLE	LOLE
3.	Number of adjacent Areas/internal sub-Areas modeled	-/6	-/3	3/13	4/11 Zones	-/10
4.	Interconnections explicitly modeled	No	No	Yes	Yes	No
5.	Load forecast uncertainty represented	Yes	Yes	Yes	Yes	Yes
6.	Basis for installed reserve assumed for interconnected systems	N.A.	N.A.	0.1 days/yr LOLE	> 0.1 days/yr LOLE	N.A.
7.	Internal Area transmission modeled for resource adequacy assessments	Yes	Yes	Yes	Yes	Yes
8.	Interconnection outages modeled	No	No	Yes [c]	Yes [b]	No
9.	Year of Recent NPCC Area Comprehensive Review of Resource Adequacy [5]	2008 [d]	2010 [e]	2008 [f]	2009 [g]	2009 [h]

[a] Loss of Load Expectation equal to 0.1 days/year
[b] Outages modeled on cables into New York City and Long Island.
[c] Outages modeled on Hydro-Quebec and New Brunswick interconnections.
[d] 2008 Comprehensive Review of Québec Area Resource Adequacy approved March 11, 2009.
[e] 2010 Comprehensive Review of Maritimes Area Resource Adequacy approved September 9, 2010.
[f] 2008 Comprehensive Review of New England Area Resource Adequacy approved November 19, 2008.
[g] 2009 Comprehensive Review of New York Area Resource Adequacy approved March 10, 2010.
[h] 2009 Comprehensive Review of Ontario Resource Adequacy approved September 10, 2009

[5] See: http://www.npcc.org/documents/reviews/Resource.aspx

Table 2 shows the interconnected Areas that are modeled when each Area performs its respective NPCC Comprehensive Review of Resource Adequacy. The following table is read from left to right (e.g. the New York Area considers interconnections with the Québec, New England, Ontario and PJM Areas).

Table 2
INTERCONNECTIONS MODELED BY NPCC AREAS

Area Doing Study	Interconnections Modeled in Area Studies						
	Québec	Maritimes	New England	New York	Ontario	RFC	PJM
Québec	-	-	-	-	-	-	-
Maritimes	-	-	-	-	-	-	-
New England	X	X	-	X	-	-	-
New York	X	-	X	-	X	-	X
Ontario	-	-	-	-	-	-	-

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 [6] 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 sub-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 sub-Area at the time of its daily peak load. If an isolated sub-Area has a negative capacity margin, the model seeks to initiate transfers from sub-Areas with a positive capacity margin. Available reserves are allocated among deficient sub-Areas on a shared basis in proportion to Sub-Area shortfalls, with priority given to sub-Areas within the same Area. 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.

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

3.2 MODELING ASSUMPTIONS

(1) Transfer Limits

Figure 1 illustrates the Areas and transfer limits assumed for the years 2011 to 2015 study period. Tie transfer limits between Areas and sub-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.

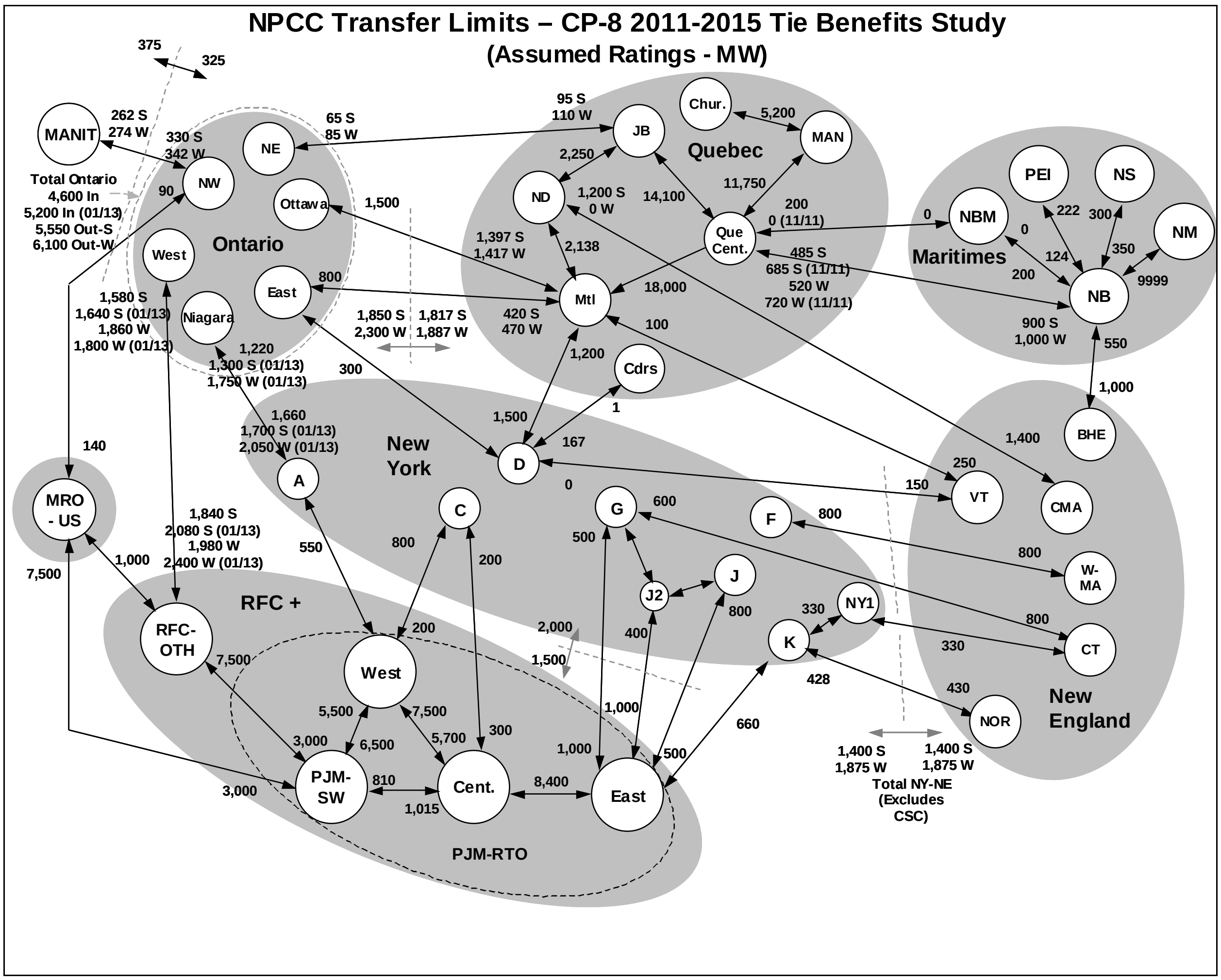

Figure 1 - Assumed NPCC Transfer Limits (MW) – 2011 to 2015
(Annual ratings unless noted as S – Summer or W – Winter)

The acronyms used in Figure 1 are defined as follows:

Chur	- Churchill Falls	NOR	- Norwalk – Stamford	NM	- Northern Maine
MANIT	- Manitoba	BHE	- Bangor Hydro Electric	NB	- New Brunswick
ND	- Nicolet-Des Cantons	Mtl	- Montréal	PEI	- Prince Edward Island
BJ	- Bay James	C MA	- Central MA	CT	- Connecticut
MN	- Minnesota	W MA	- Western MA	NS	- Nova Scotia
MAN	- Manicouagan	NBM	- Millbank	NW	- Northwest (Ontario)
NE	- Northeast (Ontario)	VT	- Vermont	RFC	- Reliability*First* Corp.
MRO	- Midwest Reliability Organization	Que	- Québec Centre Centre	MT	- Maritimes Area

(2) Load Model

Figures 2(a) and 2(b) shows the resulting diversity in load shapes between the NPCC Areas forecast for the years 2011 and 2015, respectively. The Canadian Maritimes and Quebec are winter peaking while the US Areas and Ontario are summer peaking. This seasonal difference in the annual peak load contributes to the interconnection assistance available to each Area.

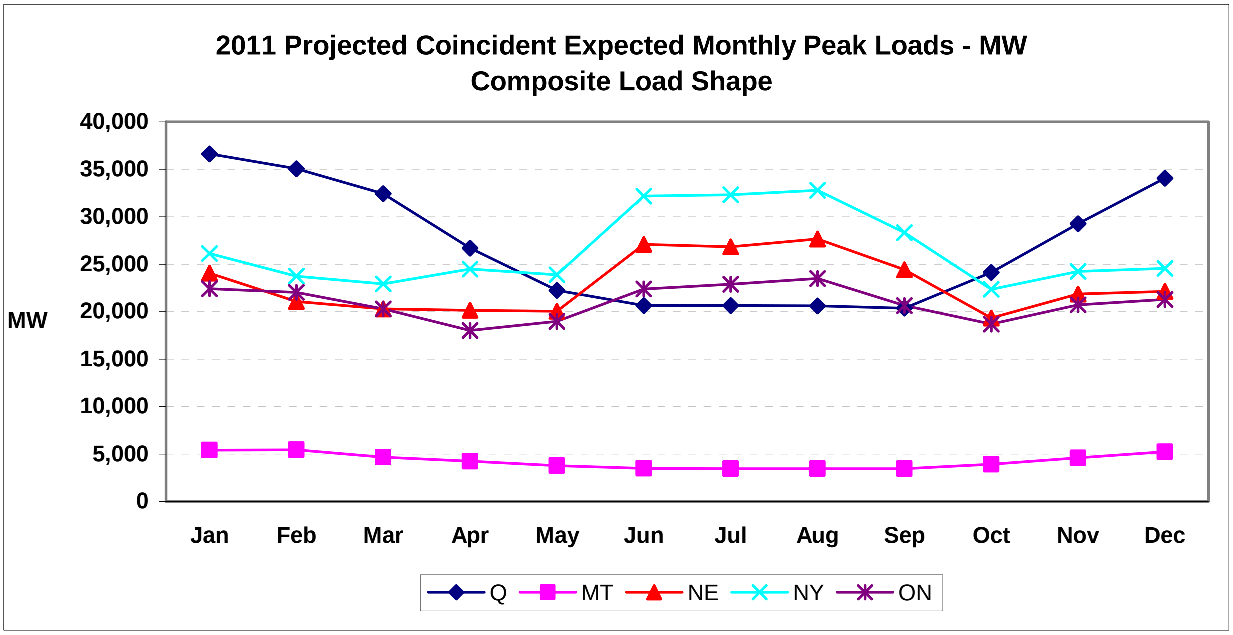

Figure 2(a) - 2011 Forecast Monthly Peak Loads for NPCC Areas

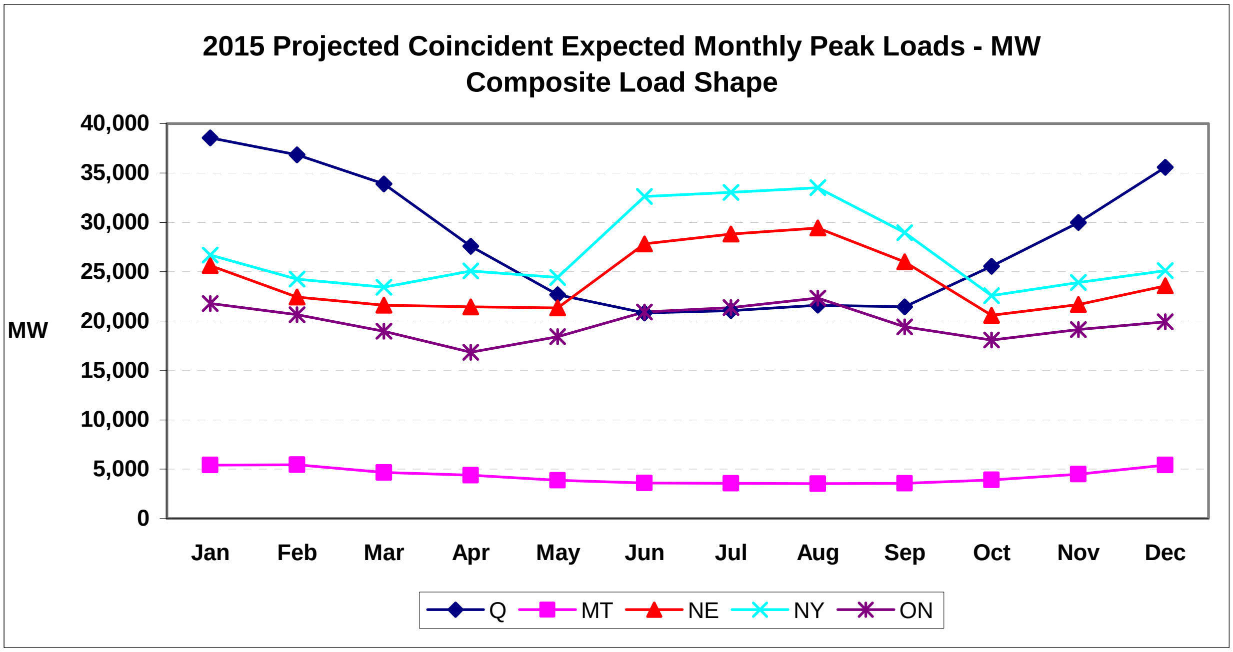

Figure 2(b) - 2015 Forecast Monthly Peak Loads for NPCC Areas

(3) Generation Resources

Each Area provided its projections of "As Is" available resources consistent with their forecasts for the years 2011 (Table 3(a)) and 2015 (Table 3(b)), as of the Area's peak month. 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 Peak Month 2011 - MW
"As Is"

	Q (Jan) [7]	MT (Feb)	NE (Aug)	NY (Aug)	ON (Aug)
Assumed Capacity	37,857	7,147	29,767	39,934	31,532
Purchase/Sale	1,768	-200	1,011	2,948	0
Peak Load	36,625	5,430	27,658	32,790	23,497
Demand Response	0	0	1,953	0	1,175
Reserve (%)	8	28	20	31	19
Scheduled Maintenance	0[7]	806	0	609	788

Table 3(b)
NPCC Capacity and Load Assumptions for Peak Month 2015 - MW
"As Is"

	Q (Jan) [7]	MT (Feb)	NE (Aug)	NY (Aug)	ON (Aug)
Assumed Capacity	39,728	6,904	32,408	40,030	26,858
Purchase/Sale	2,222	0	184	2,948	0
Peak Load	38,566	5,469	29,436	33,506	22,334
Demand Response	0	0	2,445	0	1,346
Reserve (%)	9	26	21	28	28
Scheduled Maintenance	0[7]	135	0	625	88

(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).

(5) Assistance Priority

With the exception of the Milbank units, excess reserves and operational assistance were allocated among all of the Areas and sub-Areas with deficiencies in proportion to their deficiencies. The Millbank Station, although located within the Maritimes, has two of its units

[7] Capacity shown for Québec adjusted for scheduled maintenance.

contracted to Québec. These units are modeled as a resource for Québec first, to reflect their priority order of assistance. If not required by Quebec, their output is then made available to the Maritimes. This contract was modeled as ending on October 31, 2011.

(6) Operating Procedure Assumptions

Table 4 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 4
NPCC Operating Procedures Assumptions (Peak Month 2011)
(MW or % of Load)

Actions	Q (Jan)	MT (Feb)	NE (Aug)	NY (Aug)	ON (Aug)
1. Curtail Load / Utility Surplus	1,073	0	412	0	315
Appeals	0	0	0	0	1.00%
RT-DR / SCR / EDRP	0	0	682	233	0
SCR Load / Man. Volt. Red.	0	0	0	5.49%	0
2. No 30-min Reserves	500	229	744	600	473
3. Volt. Red. / Inter. Load *	250	380	0	1.53%	0
RT-EG	0	0	488	0	0
4. No 10-min Reserves	750	660	0	0	1,080
Voltage Reduction	0	0	1.50%	0	0
Appeals / Curtailments	0	0	0	188	0
5. 5% Voltage Reduction	0	0	0	0	2.60%
No 10-min Reserves	0	0	1,079	1,200	0

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

(7) Load Forecast Uncertainty

Table 5 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 5 shows the values assumed for the peak month of each Area. Table 5 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 5
Per Unit Variation in Load Assumed for the Area Peak Month 2011

Area	Per-Unit Variation in Load						
Q (Jan)	1.0853	1.0639	1.0426	1.0000	0.9573	0.9360	0.9146
MT (Feb)	1.1000	1.1000	1.0500	1.0000	0.9500	0.9000	0.9000
NE (Aug)	1.2500	1.1210	1.0039	0.9388	0.8970	0.8864	0.8513
NY (Aug)	1.1002	1.0817	1.0410	0.9927	0.9400	0.8858	0.8486
ON (Aug)	1.1537	1.1025	1.0512	1.0000	0.9488	0.8975	0.8463
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 is a multi-step process that seeks to determine the amount of “perfect capacity“ (capacity with no planned or forced outages) which, when added to an Area that has been isolated from the remainder of NPCC, allows the Area to maintain the same level of reliability, in terms of daily LOLE (loss-of-load expectation in days/year), as it had when interconnected.

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 LOLE as if the actual interconnections were present. This single MW value for an Area will be referred to as its **Annual Tie Benefit Potential**. In this review, the **Annual Tie Benefit Potential** includes both the non-firm emergency assistance into an Area and the net Area import from firm scheduled transactions between Areas.

The specific Steps are summarized below:

> **Step 1 –** Isolate the “As-Is” [8] Areas after scheduling firm contracts, remove any internal transmission constraints, and calculate the daily LOLE. Although this step is not required for the actual determination of the Annual Tie Benefit Potential, it does provide an indication of the reliability of each of the “As-Is” Areas which can be helpful in understanding the study results.
>
> **Step 2 –** Interconnect the Areas and restore the internal transmission constraints in all Areas except for the Area of interest. Starting with the “As-Is” capacity in each Area, adjust the capacity in the Area of interest (by adding or removing “perfect” capacity), based on the reserve margins in the sub-Area loads and subject to any locational

[8] The “As-Is” assumption refers to the modeling of systems with resources that are expected to be in-place for the years 2011 or 2015, as supplied by the CP-8 Working Group in December 2010.

requirements, until the Area is at approximately 0.1 days/year.

Step 3 – Using the adjusted capacity for each Area from Step 2, isolate the Areas after scheduling firm contracts and removing the internal transmission constraints. Add "perfect" (100% available) capacity 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" capacity for the neighboring Areas.

The reserve margin calculation used in Step 2 to determine the capacity adjustments to each sub-Area within an Area is a simple calculation that involves just the installed capacity and annual peak load of the sub-Areas. It does not consider purchases and sales, demand response, or any other adjustments that an Area may include in its own reserve margin calculations. The purpose of the reserve margin calculation as used here is to allocate the capacity adjustment in an Area between its sub-Areas. If we want to remove capacity from an Area (the usual situation), a target maximum reserve margin is determined that will result in the desired capacity adjustment to the Area. Perfect capacity is then removed from any sub-Areas that exceed the target maximum; sub-Areas below the target are left unchanged.

While adjusting the sub-Area capacities based on reserve margins is a good approach in estimating the total capacity adjustment 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 capacity adjustment 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 capacities to determine the amount of assistance (non-coincident) that the other Areas can provide (Step 2). This approach thus provides an estimate of the amount of assistance (non-coincident) that's available to an Area, regardless of whether or not an Area can make use of all of it due to internal constraints.

In Step 2, while the internal constraints were ignored in the Area of interest, 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. Failure to model the internal constraints in the Areas providing assistance could overstate the amount of assistance that they are actually able to deliver to their borders.

In Step 3, the Areas start with the adjusted capacities determined in Step 2 and are isolated from one another after scheduling the firm contracts and removing the internal constraints. Perfect capacity is then added to each Area until it returns to the target LOLE from Step 2, approximately 0.1 days/year. This then determines for each Area the single annual MW amount that is equivalent, on an annual basis, to the reliability benefits provided by the interconnections. This amount, when added to the next firm imports at time of Area peak, is the "As-Is" Annual Tie Benefit Potential.

The above methodology was used for both 2011 and 2015 and provided an estimate of the "As-Is" Annual Tie Benefit Potential assuming the "As Is" capacity 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 (including outside regions), with internal transmission constraints, to approximately 0.1 days/year LOLE by adjusting the capacity in each Areas based on the reserve margins in the sub-Areas, subject to any locational requirements.

Step 5 – Starting with the adjusted capacities from Step 4, remove the internal transmission constraints in the Area of interest and adjust its sub-Area capacity, based on reserve margins and subject to any locational requirements, until it returns to the LOLE in Step 4. This step is the same as Step 2 except for the capacity in the Areas providing assistance.

Step 6 – Using the adjusted capacity for each Area from Step 5, isolate the Areas after scheduling firm contracts and removing the internal transmission constraints. Add “perfect” (100% available) capacity to each Area for the entire year until the Area LOLE returns to the LOLE calculated in Step 5 (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 “At-Criteria” capacity for the neighboring Areas. This amount, when added to the next firm imports at time of Area peak, is the “At-Criteria” Annual Tie Benefit Potential.

3.4 RESULTS

The **Annual Tie Benefit Potential** is shown are shown in Table 6(a) for the year 2011 and Table 6(b) for the year 2015. These results indicate the range of the Tie Benefit potential, regardless of whether or not an Area can make use of it due to its internal constraints. For reference, also shown in Table 6(a) and Table 6(b) is the Area’s net firm imports and total import capability at time of their peak load.

With all of the Areas being more reliable than 0.1 days/year under the “As-Is” assumptions, the “As-Is” **Annual Tie Benefit Potential** for each Area is nearly equal to its import capability. This indicates that with the Areas as currently forecast, they all have plenty of assistance available to provide to the other Areas, with the constraining factor being the capability of the ties to deliver it to the receiving Area.

As would be expected, the “At-Criteria” **Annual Tie Benefit Potential** is somewhat less than the “As-Is” values, reflecting the lower available reserves in the Areas providing the assistance.

Table 6(a)
Annual Tie Benefit Potential (MW) – 2011

NPCC Area	"As-Is" Annual Tie Benefit Potential	"At-Criteria" Annual Tie Benefit Potential	Net Firm Imports at Time of Peak	Total Tie Capability Assumed Available at Time of Area Peak
Québec	4,004	3,409	504	4,017
Maritimes	1,353	1,076	-200	1,550
New England	4,251	3,246	1,111	4,380
New York	8,538	4,393	1,888	8,807
Ontario	4,800	2,660	0	4,800

Table 6(b)
Annual Tie Benefit Potential (MW) – 2015

NPCC Area	"As-Is" Annual Tie Benefit Potential	"At-Criteria" Annual Tie Benefit Potential	Net Firm Imports at Time of Peak	Total Tie Capability Assumed Available at Time of Area Peak
Québec	3,747	2,892	847	4,017
Maritimes	1,536	1,252	0	1,550
New England	4,244	2,709	284	4,380
New York	7,788	5,088	1,888	8,847
Ontario	4,990	3,690	0	5,200

3.5 COMPARISON OF AREA INTERCONNECTION ASSISTANCE

Table 7 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 two NPCC Areas (New England and New York) that assume interconnection assistance in their resource adequacy assessments.

Table 7
Comparison of Assumed and Estimated
Annual Interconnection Assistance – MW

NPCC Area (Year of Review)	Assistance Reported in Recent NPCC Review of Resource Adequacy	2011 Net Firm Area Imports at Time of Peak	Range of Estimated Annual Tie Benefit Potential for 2011	2015 Net Firm Area Imports at Time of Peak	Range of Estimated Annual Tie Benefit Potential for 2015
Québec (2008)	0	504	3,409 – 4,004	847	2,892 – 3,747
Maritimes (2010)	0	-200	1,076 - 1,353	0	1,252 – 1,536
New England (2008)	1,800	1,111	3,246 – 4,251	284	2,709 – 4,244
New York (2009)	1,861[9]	1,888	4,393 – 8,538	1,888	5,088 – 7,788
Ontario (2009)	0	0	2,660 – 4,800	0	3,690 – 4,990

New England Update

The New England Resource Adequacy Criterion is used to determine the amount of capacity resources needed to reliably satisfy system demand. In calculating the amount of capacity resources needed, New England also takes into account the tie benefits that are assumed available from the neighboring systems.

New England's directly interconnected neighboring bulk power systems are represented by tie benefits in their NPCC Comprehensive Review. These tie benefits are derived based on results of studies conducted by ISO New England using the GE MARS program. In these tie benefit studies, all the interconnected Areas are assumed to be at the 0.1 days/year resource adequacy criterion simultaneously. The Area's load, resource (including load and/or capacity relief assumed available from implementing emergency operating procedures) and transmission interface transfer capabilities are based on the latest available data from each Area. ISO-New England updates its tie benefit studies according to its market rule requirements. Based on the latest tie benefits study results, the tie benefits values used for New England's Forward Capacity Market and resource adequacy studies are 1,800 MW for year 2011 [10], 1,665 MW for 2012 [11], 1,700 MW [12] for 2013, and 1,689 MW for 2014 [13].

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[9] New York's 2009 Comprehensive NPCC Resource Adequacy Review was based on the New York Control Area Capacity Requirements for the Period May 2009 through April 2010 - See: http://www.nysrc.org/pdf/Reports/2009%20IRM%20Report%20-%20Final%2012%2005%2008%20V1.pdf.

[10] See New England FERC filing: http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1512-000_9-9-08_2011-2012_icr_filing.pdf

[11] See New England FERC filing: http://www.iso-ne.com/regulatory/ferc/filings/2009/jul/er09-___-000_7-7-09_2012-2013_icr_values.pdf

[12] See New England FERC filing: http://www.iso-ne.com/regulatory/ferc/filings/2010/may/er10-1182-000_05-04-10_icr_2013-2014.pdf

[13] See New England FERC filing: http://www.iso-ne.com/regulatory/ferc/filings/2011/mar/er11-3048-000_03-08-11_icr_2014-2015.pdf

New York Update

The New York State Reliability Council established the annual statewide installed reserve margin requirement of 1.155 times the forecasted New York peak load for the May 2011 through April 2012 period. [14]

An input to this study is the amount of New York installed capacity that is assumed located outside of New York. Beginning with the study year 2010, only Grandfathered capacity was modeled.

This equates to 2,120 MW of summer external capacity – 50 MW from New England, and 1,080 MW from PJM and 1,090 from HQ.

The total tie capability between New England and New York and between PJM and New York was assumed to be 1,400 MW and 1,550 MW, respectively. Total tie capability between Hydro Quebec and New York is 1,667 MW, but only 1,090 MWs were allowed to sink into New York for the 2011- 2012 Import Rights period. While the total tie transfer between Ontario and New York is 1,660 MWs, Ontario does not meet the New York requirements to sell capacity into New York.

For each capability year, New York determines how much external capacity may sink into New York from the external control areas without violating the 0.1 day/year LOLE. Any additional tie capability above those capacity limits would be available as emergency assistance.

The external capacity representation also includes Unforced Capacity Deliverability Rights (UDRs). These are rights that allow the owner of an incremental controllable transmission project to extract locational capacity benefit derived by New York from the project. The owner of UDR facility rights designates how they will be treated by the NYISO in resource adequacy studies on an annual basis.

LIPA's 330 MW HVDC Cross Sound Cable, 660 MW HVDC Neptune Cable, and the 300 MW Linden VFT are facilities that are represented as having UDR rights. Any remaining capacity beyond that identified by the owners as in use for locational capacity benefit is available to support emergency assistance.

Assuming such arrangements permits New York's installed reserve margin to be 10.1 percentage points lower than otherwise required. This equates to 3,320 MW (10.1% of the assumed peak load of 32,872 MW) of assumed Tie Benefits for New York.

[14] New York Control Area Installed Capacity Requirements for the Period May 2011 Through April 2012. See: http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.asp

4.0 CONCLUSIONS

The CP-8 Working Group concluded that:

- the methodology and assumptions used in this Review were 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.