NPCC Methodology and Guidelines for Forecasting TTC and ATC

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1. Summary

NPCC is the regional reliability council in the north-eastern US and Canada, and comprises the state of New York, the six New England States, the Canadian provinces of Ontario, Quebec, and the Maritimes.

NPCC consists of 5 control areas on the north-eastern portion of the NERC eastern interconnection. Because of NPCC's geographic location on the eastern interconnection, only the New York and Ontario control areas experience parallel flows. The remaining control areas, the Maritimes, Quebec and New England, are not subject to parallel flows, as there are no parallel flow paths to their ties with neighbouring systems. Therefore these control areas are able to operate their external ties based on scheduled energy flows. In addition, only the service reserved and scheduled on their systems will flow on their systems, so their forecasted ATC is not affected by reservations or schedules made on other systems.

The Maritimes, Quebec and New England) areas function as systems that are radial to the rest of the Eastern Interconnection. Methodologies for calculating ATC directly reflect the lack of parallel flow problems and the radial characteristics of their ties with respect to the rest of the Eastern Interconnection. The methodology prescribed here recognises the geographic and electrical characteristics of the NPCC region and that reliable forecasts for transmission service can be provided with limited co-ordination and data sharing.

The Maritimes, New England and Quebec areas are the only NPCC areas that are currently posting ATCs and offering physical transmission service for reservation on their OASIS nodes. New Brunswick Power is the only Transmission Provider within the Maritimes control area that has external ties to other control areas and therefore is the only one posting ATCs.

2. Status of Open Access in NPCC

This section gives a brief summary of the state of open access in NPCC, and helps put into context the variations in information and posting of TTC and ATC.

The status of Open Access in this region is complex and varied. Only New York and New England are under FERC jurisdiction. Only New York, New England and Quebec have FERC approved tariffs. New Brunswick Power has established a transmission tariff, however, it is not filed with FERC.

There are essentially two types of open access:
- the Physical Right Type that offers physical reservations for transmission service,
- and Financial Congestion Management Type that provides system access through electricity markets with financial congestion management.

Quebec and New Brunswick are posting TTC and ATC for the sake of offering physical reservations on their systems. Non-discriminatory access for service is offered via TTC and ATC postings on an OASIS node, where customers can request reservations for service.

New York, New England, and Ontario are operating, or will soon be operating, electricity markets where energy is scheduled based on offers and bids, and access to the transmission system is automatic upon being scheduled in the dispatch. Congestion management is accomplished through locational prices and congestion rents can be hedged via financial instruments.

More detailed information about the status of open access the types of transmission service in each Area can be found in Section 10.

3. Objective of the NPCC Methodology

3.1. Common Methodology

This document establishes a common NPCC methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that complies with non-discriminatory open access principle, the NERC definitions for TTC and ATC, the NERC Planning Standards I E 1 and I E 2, and NPCC Document A2 *Basic Criteria for Design and Operation of Interconnected Power Systems*.

3.2. Allowance for both Physical and Financial Congestion Management

In recognition of both the physical and financial congestion management mechanisms that have been approved or mandated by regulators in the NPCC region, this document addresses aspects of TTC and ATC that are common to both methods, and permits two alternative approaches where the two mechanisms are unique. This methodology is not intended to conflict with regulatory authority requirements.

3.3 NERC ATC principles

The process for determining ATC must comply with the six ATC principles contained in the 1996 NERC document, "Available Transfer Capability - Definitions and Determination". These six principles are:

1. ATC calculations must produce commercially viable results. ATCs produced by the calculations must be a reasonable and dependable indication of the transfer capabilities available to the electric power market.

2. ATC calculations must recognize the time variant power flow conditions on the entire interconnected transmission network. In addition, the effects of simultaneous transfers and parallel path flows throughout the network must be addressed from a reliability viewpoint.

3. ATC calculations must recognize the dependency of ATC on the points of electric power injection, the directions of transfer across the interconnected network, and the points of power extraction. All entities must provide sufficient information necessary for the calculation of ATC.

4. Regional or wide area coordination is necessary to develop and post information that reasonable reflects the ATCs of the interconnected transmission network.

5. ATC calculations must conform to NERC, Regional, sub-regional, power pool, and individual system reliability planning and operating policies, criteria, or guides.

6. The determination of ATC must accommodate reasonable uncertainties in system conditions and provide operating flexibility to ensure the secure operation of the interconnected network.

3.4. NPCC ATC Principles

The NPCC methodology has been designed to adhere to the principles of NERC's 1996 Available Transfer Capability Definitions and Determination Document, where applicable to the physical characteristics to the NPCC system.

NPCC also adhered to the following additional principles in the coordination of ATC calculation and posting among its member Control Areas and with the Control Areas in adjacent Regions:

1. Calculation and posting of Total Transfer Capabilities (TTCs) and ATCs must not conflict with the responsibility of the NPCC members to plan and operate their systems in accordance with the NPCC Criteria, Guides and Procedures Documents.

2. For direct interconnection or common facilities between two NPCC Control Areas, TTC determination effort must be co-ordinated, and the values established through joint studies, or agreements.

3. For direct interconnection or common facilities between two NPCC Control Areas, the definition of the interfaces must be consistent from one Control Area to the other.

4. The NPCC Regional TTC and ATC determination and posting procedures will establish a common methodology, practices and assumptions for determining Transmission Reliability Margin (TRM) and the Capacity Benefit Margin (CBM), but will permit variations in assumption of data to account for geographic differences and uncertainties arising from the differing market structures in NPCC.

5. The Regional procedures must recognize differences in operating practices and business processes among member Areas.

6. The NPCC TTC and ATC calculation and posting procedures will be available to adjoining systems in other regions and subregions. Interregional coordination of ATC calculation and posting must recognize regional differences in the market structures.

4. TTC Forecasting – Components and Assumptions

4.1. Path requirements

All Control Areas within NPCC that are offering Open Access Transmission Services, must define the TRANSMISSION PATHS for which they allow energy transfers INTO, OUT OF and THROUGH their systems. A transmission Path is defined by its Point Of Delivery (POD) where the energy is delivered to an adjacent system and its Point Of Reception (POR) where the energy is received from an adjacent system.

All electrical paths, interfaces and interconnections for which open access is offered and where congestion could occur should be identified and associated to a given PATH determined by its POR and POD. The POR and POD can be physically existing points of the network or they can represent a virtual area of the network. The TTC of a PATH is the Total Transfer Capability from the POR to the POD of that PATH. For a PATH consisting in the aggregation of segments connected in series resulting TTC will be the minimum of the series segments. *And similarly, resulting ATC will be the minimum of the series segments ATCs.*

Connectivity of the Paths through the overall network should be established by using identical POR/POD naming when applied to the same physical interconnection or interface.

4.2 Determination of TTC

The TTC across a transmission Path is the pre-contingency level of power that can safely be transferred over said Path in such a way that following the loss of the most critical element of the network, system integrity (thermal, voltage and stability limits) is maintained in concordance with system rules and practices while remaining consistent with NPCC guidelines and operating agreements. The TTC on a transmission Path is direction specific and is evaluated along its whole path.

These aspects should be considered when determining TTC:

- System Conditions - they are identified in the BASE CASE for the period being analyzed. Projected customer demands, generation dispatch, system configuration, and schedule transfer must be considered.
- Critical Contingencies - both generation and transmission system most restrictive outages must be analyzed.
- System Limits - Impact analysis of the critical contingencies on the network will determine the most restrictive of the limitations. TTCs will be based on the minimum of the three: thermal, voltage or stability limits

TTCs will be determined by completing offline computer simulations (power flows) of the transmission network under specific sets of assumed operating conditions adjusted for ambient weather conditions, planned outages, loads variation and generations dispatch. As system conditions change, the most restrictive limit on TTC may also change from one limiting element to another.

When recognizing varying loads, interruptible loads will be assumed to be served in the TTC/ATC calculations.

There are two types of paths:
a) Radial Path, where the limiting element is within the path
b) Non Radial Path, where the limiting element may be outside the path. Parallel flows occur due to network configuration.

For interconnections that transfer power between two adjacent Control Areas through the use of radial generation or load disconnected from its original system and radially connected to an adjacent system, their TTCs will reflect the minimum of the transmission capability, and the forecast maximum generation or consumption capability of the facilities (generation or load) used to accomplish the energy transfer.

TTC for non-radial paths is normally determined by a normal incremental transfer capability analysis, where generation is raised on the sending side of an interface and lowered on the receiving side. The TTC, or interface limit, is defined as the total resulting power flow on the interface when a limitation, both pre and post-contingency limitation, is reached. The monitored facilities in the analysis are usually limited to only the facilities in the vicinity of the interface. The result is an interface capability, (rather than a point to point capability) which is consistent with how NPCC control areas are publishing ATC.

All NPCC member Control Areas shall conduct operational studies on a regular basis to develop operating limits and TTCs for their respective internal network in accordance with the NERC and NPCC planning and operating policies, criteria and guides.

All Control Areas shall conduct joint operating studies with adjacent Control Areas on a regular basis to determine inter-Area operating limits and TTCs in accordance with NERC and NPCC planning and operating policies, criteria and guides, and in accordance with other mutually established, policies, criteria and guides.

4.3. Recognition of Points of Injection and Withdrawal

In order to allow TTC monitoring from the ultimate points (the initial POD and the final POR) of power injection (sources) and power extraction (sinks) across several systems, intermediate PODs and PORs must be compatible. NPCC member Control Areas shall make their transmission Path TTCs available to the NPCC. Aggregate NPCC area TTCs will be posted on the NPCC web site and made available for an overall Eastern Interconnection TTC aggregation.

4.4. TTC variations with time

The TTCs are determined for both real time use and future forecasts. Forecasts are fixed on:
- an hourly basis for the next 168 hours;
- a daily basis for the next 35 days
- a weekly basis from the next calendar week to the 5th week ahead;
- a monthly basis from the next calendar month to the 13th month ahead
- a yearly basis from the next following 2 calendar years,

TTC coordination is limited to jointly owned/operated interconnection lines, and on outage requests approved by both operating entities.

Forecast TTCs are defined according to the anticipated operating conditions within the Control Area the transmission Path area belongs to.

Forecast TTCs shall

- be maximized for load variations, generation dispatching, weather conditions and generation capacity when radial generation is used for energy transfer between non synchronous areas (reliable ATC will depend on TRM calculation methodology)
- take into account approved outage applications and known or anticipated outage plans
- take into account planned system additions/decommissioning/modifications as incorporated in the NPCC approved list of new projects

4.5. Calculation frequency

Calculation frequency for TTC determination should meet the specified timelines for the following classes of TTC:

- at every hour, before the end of the actual hour : revised TTCs for the next 24 hours and the next day
- before 3 PM (utility time) every working day: revised TTCs for the next 7 days and for the next week
- before Tuesday 3 PM (utility time) of every week : revised TTCs for the next 5 weeks and the next month
- before 3 PM (utility time) on the last Tuesday of every month: revised TTCs for the next 6 months
- every 3 month, before the end of the actual season : revised TTCs for the next 18 months and the next 2 years

4.6. How to select the TTC value to post over a continuous period

A TTC will vary on a continual basis as operating conditions on the network change: the longer the observation period, the greater the TTC variation. Among the factors affecting TTC values, transmission facility outage is one of the most important but being limited to a few days per year, it should not drive the values of the monthly and yearly TTCs.

For radial interconnections between two non-synchronous systems, TTCs will change according to load and generation capacity variation. Load varies hourly, daily and seasonally. Generation, specifically hydro plants, can vary seasonally.

TTCs posting requirements are as follows:

- TTCs posted yearly will be based on the maximum TTC for the year during the summer and winter peak seasons (June-September, December-March)
- TTCs posted monthly will be based on the maximum daily TTC for the month
- TTCs posted weekly will correspond to the minimum TTC for the week (TTCs are calculated for each hour of the week).
- TTCs posted daily will correspond to the minimum TTC for the day (TTCs are calculated for each hour of the week)
- TTCs posted hourly will correspond to the minimum TTC for the hour.

For TTC calculations that are affected by radial loads, the forecasted peak value for the period can be used. Québec is presently using peak values.

For TTCs that are affected by radial generation maximum, 90% of maximum or average generation capacity can be used. Québec is presently using maximum values and generation variation is included in TRM.

5. ATC Forecasting – Components and Assumptions

5.1. Determination of ATC

Essentially, ATC is the amount of transmission service available for use by the electric power market.

The NERC definition of ATC (as it applies to physical reservations) is a measure of transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically speaking, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin, less the sum of existing transmission commitments (which includes retail customer service and interruptible loads) and the Capacity Benefit Margin (CBM).

ATC = TTC - TRM - CBM - existing transmission commitments

The process for determining ATC must comply with the six ATC principles contained in the 1996 NERC document, "Available Transfer Capability - Definitions and Determination". These six principles are defined in chapter 3.3.

The process for determining ATC must also comply with the relevant NPCC principles contained in section 3.4 of this document.

5.2. Accounting of Firm and Non-firm Reservations and Schedules

ATC = TTC - TRM - CBM - existing transmission commitments

Existing transmission commitments can consist of reserved (planning horizon) and scheduled (operating horizon) firm and non-firm transmission service. Also, for physical reservation purposes, ATC is broken down into firm ATC and non-firm ATC values for the planning and operating horizon (schedule and real time).

<u>In the planning horizon:</u>

Firm ATC = TTC - TRM - CBM - firm reservations
Non-Firm ATC = TTC - a(TRM) - CBM - firm reservations - non-firm reservations

where $0 < a < 1$, value determined by individual transmission providers based on network reliability concerns.

<u>In the operating horizon:</u>

Firm ATC = TTC - TRM - CBM - firm reservations
Non-Firm ATC = TTC - b(TRM) - CBM - firm schedules - non-firm schedules

where $0 < b < 1$, value determined by individual transmission providers based on network reliability concerns.

5.3. Recognition of Points of Injection and Withdrawal

Due to the nature of the power systems and the market practices within NPCC, actual source (point of injection) and sink (point of withdrawal) do not need to be considered in the calculation of ATC.

Transmission providers within NPCC shall make ATC values for all applicable interfaces available to NPCC and will publish them on their respective OASIS nodes.

It is the responsibility of the party managing a transaction to secure transmission service on all necessary interfaces between the source (point of injection) and sink (point of withdrawal) of the transaction. By following this requirement, the concern regarding partial path reservations should be mitigated.

5.4. Calculation Frequency

Posted ATC values will be kept current and reflect any known changes in TTC, TRM, CBM and existing transmission commitments at a frequency consistent with chapter 4.5

5.5. Allowances for Varying Demand and How ATC assumptions vary with time

ATC calculations will not account for the uncertainties of varying customer demand. This will be addressed with TRM (see Section 7).

5.6. How to select the ATC value to post over a continuous period

Where assumptions differ significantly over a time horizon, and therefore result in varying ATC values, the ATC values will be selected for posting using the rules described in Section 4.6 for TTC values.

5.7. Netting of Transmission Reservations or Schedules

For Physical reservation systems:

- Transmission Reservations are not netted for forecasting firm and non-firm ATC.
- Firm and non-firm schedules are netted for forecasting non-firm ATC.
- Firm ATC schedules are not netted for forecasting firm ATC.

For Market based system

- All schedules are netted for forecasting ATC.

6. Capacity Benefit Margin (CBM)

6.1. Definition

CBM is the amount of Transmission Transfer Capability reserved by Load Serving Entities to ensure access to generation from interconnected systems to meet generation (capacity and energy) reliability requirements. CBM is an importing quantity only.

Within NPCC, market based systems have adopted rules to satisfy generation reliability requirements without the need for explicit transmission reservations on the market system nor the need to hold back transmission capability from the market.

Reservation of CBM by a Load Serving Entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

The CBM is a more locally applied margin as opposed to TRM, which can be a network margin.

A Load Serving Entity must maintain Policies and Procedures to maintain generation reliability requirements.

NPCC's Regional Reviews of generation adequacy will continue to permit capacity imports from the interconnected systems.

6.2. Calculation

CBM must be calculated for:

a) the long-term planning period, using the probabilistic methods such as Loss of Load Expectation (LOLE) of 0.1 day per year. Input data consists of unit forced outage rates, maintenance outages, minimum downtimes, load forecasts, fuel restrictions, low hydraulic conditions, etc. The methodology used to derive CBM must be documented and consistent with published Transmission Provider and NPCC planning criteria. (This may require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.)

   All loads, with the exception of interruptible load, connected to the Transmission Provider system are included and assumed to be served in the determination of the CBM requirement.

b) the long-term operating period (one year to a month), CBM is expected to gradually decrease to zero.

c) the short-term operating period (up to one month), CBM must be zero.

The sum of the CBM values allocated to all interfaces shall not exceed that portion of the generation reliability requirement that is to be provided by outside resources.

Generation reserve sharing arrangements or an LSE generation resource not directly connected to the LSE transmission provider's system but serving LSE loads connected to the transmission provider's system will require an explicit reservation.

Generation connected to the transmission provider's system that is not obligated to serve native/network load connected to the transmission provider's system will be included in the calculation to satisfy the LOLE requirement.

Formal request for variances from the Regional CBM methodology may be sent to NPCC for review and approval by the NPCC Task Force on Coordination of Planning (TFCP) and Task Force on Coordination of Operations (TFCO).

Transmission Provider or its delegate can define CBM of zero MW on its interfaces with other entities, if the generation capability internal to its system satisfies its load and reserve requirements.

The Transmission Provider, or its delegate will periodically review the CBM values to account for seasonal variations in load and resource data.

The Transmission Provider, or its delegate will publish the CBM values.

6.3. Allowable Use of CBM

Each transmission provider shall document and make available its procedures on the use of CBM (scheduling of electrical energy against a CBM preservation) to NPCC, NERC, and the transmission users in the electricity market. These procedures shall:

- Require that CBM is to be used only in an emergency after the following steps have been taken (as time permits): all non-firm sales have been terminated, direct-control load management has been implemented, and customer interruptible demands have been interrupted. CBM may be used to re-establish operating reserves.
- Require that CBM shall only be used if the LSE calling for its use is experiencing a generation deficiency and its transmission provider is also experiencing transmission constraints relative to imports of energy on its transmission system.

6.4. Reporting of Use of CBM

Each transmission provider shall publish the use of CBM by the load-serving entities' loads on its system, except for CBM sales as non-firm transmission service. This disclosure may be after the fact.

7 Transmission Reliability Margin (TRM)

7.1. NPCC approach to TRM

Transmission Reliability Margin (TRM) provides a degree of assurance that uncertainties in system conditions will not impair the reliability of the transmission network. Each NPCC Transmission Provider is responsible for assessing an appropriate TRM for each path (or interface) to be used when calculating ATC values. Different TRM values may be used for firm and non-firm ATC.

NPCC allows each TP

- to determine which components are used in the TRM calculation,
- to define the contribution of those components based on their particular system requirements, and
- to document a probability method used.

The goal is to minimize TRM requirements while maintaining system and market reliability. TRM can be offered for non-firm ATC as indicated in the calculation of ATC formula in Section 5.2.

7.2. Components for TRM Determination

The following factors should be considered to account for uncertainties in systems conditions:

7.2.1. Aggregate Load Forecast Error

Sufficient TRM should be maintained for load not included in determining generation reliability requirements.

7.2.2. Load Distribution Error

Sufficient TRM should be maintained for deviations from load forecast, both active and reactive, as an example, caused by severe weather.

7.2.3. Variations in facility loading

Sufficient TRM should be maintained for deviations from load forecast due to balancing of generation within a control area.

7.2.4. Uncertainties in system topology

Traditionally, planning horizon studies have used first contingency reliability criteria to assess transfer capability for peak load conditions. These studies have focused on assessing transmission transfer capability with single transmission outages on the system. More stringent planning and operating criteria such as analysis of contingencies may be used for the determination of TRM.

7.2.5. Simultaneous Transfers and Parallel Path Flow

Sufficient TRM should be maintained to allow for the effects of simultaneous transfers and parallel path flow (unscheduled flow) on a Transmission Provider’s system.

7.2.6. Variations in Generation Dispatch

Sufficient TRM should be maintained to allow for variations in generation dispatch. Location and output of generation in planning and pre-operational horizons may be vastly different from actual conditions at the time of operations. Further, some TTCs and ATC are highly sensitive to generation output and reactive support of some key generating units. TRM calculations should provide for variations in TTCs for the outage of generation units at or near transmission interface under study, if not already considered in the determination of the TTC of that interface.

7.2.7. Calculation Inaccuracies

Sufficient TRM should be assumed to account for the limitation of the TTC calculation method. For instance, when linear techniques are used for the calculation of TTC, facility loadings may differ slightly from the typical AC power flow solution. If these differences in loading affect critical facilities that respond to transfer, then the need for additional TRM may be appropriate. Sensitivity studies may be used to establish typical level of TRM.

7.2.8. Short-term operator response factor

Sufficient TRM should be assumed for operating reserve actions not exceeding a 59-minute window. This will allow a transmission entity to fulfil its obligations to deliver or its ability to receive its share of operating reserve.

The preferred method for allocating transmission service for the purpose of operating reserve is via a specific transmission reservation. This will allow a transmission entity to fulfil its obligations to deliver or its ability to receive its share of operating reserve.

7.2.9. Short-term versus long-term time frames

TRM will be viewed differently for short-term versus long-term frames and should be adjusted to reflect uncertainties as function of time frame. In the Operating Horizon, the expected system conditions, including the removal of all facilities expected to be out of service and the effect of available operating procedures can be analyzed with a reasonable degree of certainty and accuracy. Since there is less uncertainty for this period, it may be appropriate to reduce TRM. Studies in the Planning Horizon normally assume all facilities are in service except for the studied contingency. Studies for this period contain more uncertainty which should be reflected in the TRM value.

Where any of these factors are not coincident (e.g. one component occurs in one period and another component in a different period), they must not be added in determining TRM.

NPCC Transmission Providers using any additional component of uncertainty must document its benefit to the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations. Formal request for variances from the Regional TRM methodology may be sent to NPCC for review and approval by TFCP and TFCO.

7.3. Frequency of TRM Updates

Transmission Providers operating paths or interfaces in the NPCC Region are required to use the NPCC TRM Methodology when determining TRM values for use in ATC calculations. Transmission Providers are also required to periodically update TRM values, as a minimum once per season. New TRM values should available to NPCC, NERC, and other transmission users in the electricity market. [How? Does NPCC mandate a minimum publication method?]

7.4. Intra-NPCC

NPCC Transmission Providers with mutual interfaces are required to share TRM values on each side of the interface.

7.5. Interregional

NPCC Transmission Providers with interfaces to Transmission Providers in other NERC Regions are required to share TRM values on each side of the interface with corresponding Transmission Providers of adjacent Regions.

8. Data Co-ordination

NPCC consists of 5 control areas on the northeastern portion of the NERC eastern interconnection. Because of NPCC's geographic location on the eastern interconnection, only New York and Ontario experience parallel flows. The remaining systems, New Brunswick, Quebec and New England, are not subject to parallel flows, as there are no parallel flow paths to their ties with neighbouring systems. Therefore these areas are able to operate their external ties based on scheduled energy flows. In addition, only the service reserved and scheduled on their systems will flow on their systems, so their forecasted ATC is not affected by reservations or schedules made on other systems.

These areas function as systems that are radial to the rest of the Eastern Interconnection. Methodologies for calculating ATC directly reflect the lack of parallel flow problems and the radial characteristics of their ties with respect to the rest of the Eastern Interconnection. These three areas are the only NPCC areas that are currently posting ATCs and offering physical transmission service for reservation on their OASIS nodes.

8.1. Intra-NPCC

8.1.1. General System Conditions

Control areas of Quebec, Maritimes and New England are able to operate their external ties based on scheduled energy flows, because there are no electrically parallel paths to these systems. This means for each of New Brunswick, ISO New England and Quebec, only energy scheduled by a control area will flow through that control area. Therefore the forecast of TTC and ATC for these systems and their ties can be forecasted largely by forecasting conditions controlled or known by the two adjoining systems. In most cases if each considers the conditions in their own system, the most limiting of the TTCs will limit the total scheduled between the two systems.

For all of Quebec ties with neighbouring NPCC areas, all transfers are accomplished via asynchronous DC ties, or by synchronous ties whereby load or generation is physical disconnected from one system and re-connected to another system. In each case the tie is normally the limiting element in the transfer capability into or out of Quebec. [Discussion of internal limitations to be completed.] In some cases where load or generation is physically switched from system to another, the available amount of the load or generation is the limiting factor.

The control area interconnections between New Brunswick and New England, and between New England and New York consist of multiple circuits, but in both cases the actual flow is completely determined by the net schedule between the two control areas (ignoring control error).

For these systems, TTC and ATC in one system or its ties, is relatively independent of load level, generation dispatch, transmission reservations and energy schedules outside its system. Therefore NPCC members are encouraged, but not required to co-ordinate this information Only the ties between Ontario and New York are subject to parallel flows, and these flows must be considered when forecasting the transfer capability between the two systems, or with ECAR and PJM, to prevent significant over-scheduling of the ties.

8.1.2 Limiting Facilities and Contingencies

The ties interconnecting New Brunswick, New England, Quebec and New York represent essentially series connections to bulk system transfers such that the allowable flow, or reservation, will be restricted by the most limiting system or facility along the path. Therefore these systems normally need only consider facilities and contingencies on their own systems.

NPCC members are required, via periodic joint studies, to identify limiting facilities and their ratings, and the most limiting contingencies. These must be shared. For specific outage conditions, NPCC members must notify neighbouring systems of outages to facilities that can affect an external system. These facilities are listed in the NPCC critical facilities list, which is updated at least annually. When outages are planned to these facilities, the neighbouring system must be notified so that each area can assess the effect of the outage on its system. (Reference NPCC Document C-13, *Operational Planning Coordination*)

8.2. Interregional

NPCC members participate in the following information exchange processes that will be used for the ATC and TTC forecasting.

- NPCC annually participates in providing load flow models to the NERC Muliregional Modeling Working Group.
- - Seasonal base cases are developed jointly by the MAAC-ECAR-NPCC and VACAR-ECAR-MAAC Working Groups.
- Outage information as defined in the Critical facility list are exchanged on a regular basis to notify the affected Control Areas.
- Weekly conference calls are conducted to provide updates on conditions that could affect neighbouring Control Areas.
- NPCC Areas participate in the NERC System Data Exchange (SDX) on a daily basis.
- Transaction Information System provides all the short term transactions information.

9. Co-ordination of TTC and ATC Forecast Values

All Area to Area interfaces in NPCC are defined in a consistent manner

9.1 Intra-NPCC

Control areas in NPCC will be posting TTCs and ATCs on various OASIS nodes. The OASIS nodes used by each of the Areas are provided in Section 10 of this document. Information is provided on these OASIS nodes to assist transmission customers. A list of the Regions and Control Areas, and information on how to move between the different nodes is provided by the transmission provider's OASIS web page and on the Region web page.

With this capability, transmission users will be able to identify different ATCs of an inter-Area interface posted on different OASIS nodes.

9.2 Interregional

NPCC is interconnected with ECAR, PJM and MAPP. Coordination of ATC determination and posting with these Regions differs from one Region to another.

Under NPCC operating guides, a weekly conference call is held to discuss any conditions which are expected to have inter-Area impacts. Staff of all NPCC members participates in these calls. PJM staff will join the calls when appropriate. These weekly teleconferences allow the control areas to assess the potential impacts of generation and transmission outages on their own system conditions. TTCs for inter-Area ties are adjusted by the control areas according to the expected impact, if any.

All NPCC member Areas conduct operational studies on a regular basis to develop total transfer capabilities (TTCs) and/or operating limits for their respective internal networks in accordance with the NERC and NPCC planning and operating policies, criteria and guides. All Areas conduct joint operating studies with adjoining Areas on a regular basis to determine inter-Area total transfer capabilities and/or operating limits, in accordance with the NERC planning and operating policies, criteria and guides, and in accordance with the mutually established policies, criteria and guides. In the operational planning time frame, interconnection TTCs are in most cases a consistent set. Planned and on-going forced transmission and generation outages are taken into consideration in the determination and coordination of TTCs.

9.2.1 Coordination with PJM

PJM determines ATCs using the distributed network approach. The network ATCs are then converted into control area to control area (please verify) ATCs, and posted on their OASIS. Essentially, this approach allows for coordination with adjacent Regions irrespective of the other Regions' calculation and posting methodology. Currently, the interface names defined by New York and PJM are different. A cross reference of interface names between New York and PJM is also provided in Appendix A.

9.2.2 Coordination with ECAR

ECAR determines ATCs using the distributed network approach. ECAR transmission providers calculate a source to sink ATC as restricted by their own facilities. Its regional co-ordination procedure requires that each provider submit these calculated ATC values to the ECAR co-ordination system (CS). This internet-based computer system determines the lowest of all of the submitted ATCs and returns these values to the transmission providers. ECAR providers must then consider these values when posting source to sink ATC values on their OASIS nodes. ECAR neighbouring regions are invited to participate and submit values to the ECAR CS to improve ATC co-ordination between ECAR and its neighbours.

HydroOne and IMO have been submitting forecast ATC values on limited basis. However, as Ontario moves to restructure its electricity market, without the need to offer physical transmission reservations, or post ATC for physical reservation, the IMO control area is reviewing the value of its continued participation in the ECAR CS. Irrespective of the level of participation in the ECAR CS, IMO will continue to participate in joint operating studies, will jointly establish direct path transfer capabilities between the Michigan and Ontario systems, and co-ordinate interface limits posted over the ISN for the NERC Market Re-dispatch program. IMO is currently posting actual flows and limits on its southern Ontario flowgates.

As Ontario restructures its electricity market, the IMO will review the need and methodology for co-ordinating its financial transmission rights with the physical ATC values posted by ECAR transmission providers.

9.2.3 Co-ordination with MAPP

The MAPP centre calculates cross-regional ATCs, while individual transmission providers are responsible for calculating and posting ATC on their ties to external regions.

NPCC is directly interconnected with MAPP through the Ontario-Manitoba 230 kV ties and the Ontario-Minnesota 115 kV tie. Both sets of ties are equipped with Phase Angle Regulators (PARs) that are normally operated to hold scheduled power flows, thereby blocking potential parallel flows. Operating limits and interface TTCs are established jointly by Operating Studies Working Groups involving Manitoba, Ontario and Minnesota. Because the ties are operated to scheduled flow, and all scheduled transactions are known to both parties, and since Ontario is not offering physical transmission reservations nor posting ATC, there has not been a need to co-ordinate ATC values with MAPP. As Ontario restructures its electricity market, the IMO will review the need and methodology for co-ordinating its financial transmission rights with the physical ATC values posted by MAPP transmission providers.

9.2.4 Coordination of Interdependent TTCs

Currently, there is a multi-dependent relationship among the Quebec to New England transfer, Quebec to New York transfer, New York’s Central-East transfer and PJM’s West-Central transfer. These multi-relationships are depicted in the respective Areas' security operating instructions and form the basis of coordinated operation. A similar relationship exists in the Ontario-Manitoba transfer, the Ontario-Minnesota transfer, the Manitoba-US transfer and the Ontario internal East-West transfer.

Presently, transmission customers are required to request services from the transmission providers who, upon request, will have an opportunity to conduct security assessments prior to accepting transmission service reservations. It is envisioned that when transmission service is requested, assessment of transmission services on any one of the four interfaces will take into consideration the actual and expected transfers on the other three interfaces via established data link and/or voice communication.

10. Types of Transmission Service Available in NPCC

10.1. Ontario - IMO

10.1.1. Market Information

In the Ontario market, the IMO will administer access to the market, in place of physical reservations for access. The following are expected to have transmitter licences:

- HydroOne, one of the successor companies to Ontario Hydro, holding the majority of transmission assets in Ontario,
- Canadian Niagar Power (CNP), supplying load to the town of Fort Erie and its surrounding territory,
- Great Lakes Power (GLP) supplying the city of Sault Ste. Marie and its surrounding territory,

The Ontario market will be an electricity market allowing participants to buy and sell energy via bilateral contracts and an energy spot market. The schedules for injection will be determined from sellers' minimum offer prices to sell quantities of electricity, while schedules to withdraw energy will be determined from buyers maximum bid price to buy quantities of electricity. Loads that submit bids (quantities and price) are called dispatchable loads, as they are indicating their willingness to respond to prices. Loads that do not submit bids are called non-dispatchable loads; they are essentially price takers.

The final dispatch is determined from the combination of bids and offers that maximises the gains from trade. A uniform clearing price for energy will be calculated from the selected bids and offers. This price will be applied to all participants inside Ontario. Participants outside Ontario who are offering or bidding to the Ontario market across control area ties, will be subject to a congestion charge that reflects congestion on the ties. When no congestion exists, the external participants will be settled at the Ontario price.

10.1.2 Transmission Access

In Ontario, access to the market is via the IMO dispatch. Buyers and sellers are selected to the dispatch from their bids and offers that maximize the gains from trade, i.e. the lowest offers to sell combined with highest offers to buy. Transmission access is automatic to those bids and offers that are selected in the dispatch.

10.1.3 Congestion Management

The Ontario market will be using a hybrid method of congestion management. All participants outside of Ontario who will be injecting or withdrawing via an external tie line will be exposed to a congestion charge. This charge is applied only when congestion exists, and will reflect the price difference across the tie line. Congestion can arise, for example when there is an excess of low priced generation offers to sell into Ontario. Only the lowest priced offers up to the capability of the tie, will be selected, and the price in the external zone will reflect this lower price relative to the internal Ontario price.

In Ontario, a uniform clearing price for energy will be calculated based on scheduling optimum bids and offers, including the accepted bids and offers from external ties. This uniform clearing price ignores internal constraints. A second dispatch is then calculated to identify internal constraints. The actual real-time operational dispatch will be based on the second dispatch, and the additional re-dispatch costs will be charged to all market participants as a congestion management charge.

10.2. New York ISO

10.2.1 Market Information

The NYISO has been designated as the Transmission Provider for transmission service in NY Control Area by the eight transmission owners in New York and is responsible for coordinated operation between the NY utilities and neighbouring pools. The NYISO maintains and operates an OASIS as part of the market based system, Locational Based Marginal Pricing, currently deployed.

Customers in NY access the market through the NYISO Market Information System (MIS), an internet based tool, the NYISO web site. This system allows customers to bid in resources and make offers for service on a day ahead and hour-ahead basis for real time use. These offers, when accepted, are then made available for real time operations.

Schedules are assigned based on financial bids that are evaluated on an economic and security basis. Accepted bids for generation and load are provided schedules following a security constraint economic commitment. These schedules are provided as a result of the day-ahead evaluation and the hour-ahead evaluation. Transmission service is provided by the ISO as part of the accepted schedules. This market does not require a Transmission Reservation process.

10.2.2 Transmission Access

The NYISO monitors three time frames for evaluating energy product bids and providing transmission access to accepted bids and transactions; a day-ahead, hour-ahead, and real time evaluations. Day-ahead bids are evaluated for service requests for the following operating day and result in forward contracts for energy and associated transmission service for the accepted twenty-four hour period of the next day. Hour-ahead evaluates bids and provides advisory schedules that are made available to the real time market. A forward contract is not provided following the hour-ahead results. The ultimate energy cost is determined by real time evaluations. In both cases the accepted external schedules are subject to “check out” with associated parties.

The LBMP system does not require the reservation of transmission prior to the implementation of these two evaluations. The system assigns transmission based on an economic and a system security basis. Different then a reservation system, customers interested in obtaining service in NY must offer financial bids for energy services into the MIS for a particular period. The commitment process evaluates these bids and assigns schedules for accepted bids. These accepted schedules include transmission service.

Available Transmission Capability (ATC) is calculated and posted following the day ahead and the hour ahead evaluations. The method used to calculate ATC is as defined in Section 5 of this document. The resources that were provided schedules and the accepted transactions provide are defined as the Transmission Interface Flow Utilization, resulting from the day-ahead and hour-ahead processes. The Transmission Interface Flow Utilization values are used in the ATC calculation as the existing transmission commitments.

10.2.3 Congestion Management

The LBMP system includes a security constrain, economic commitment (SCUC) for each evaluation period. Each financial bid and bilateral transaction is evaluated on an economic and security basis. This SCUC process monitors system limitations due to thermal, voltage and stability limits. Forward contracts are assign that do not violate these limitations for the day-ahead evaluation and advisory schedules are assigned following the hour-ahead evaluation.

The NYISO also operates a Security Constraint Economic Dispatch (SCD) program for real time operation. The NYISO is dispatched in real time, using accepted bids and transactions supplied to the hour-ahead market, while monitoring system restrictions due to thermal, voltage and stability limitations.

A transmission customer must indicate their willingness to pay congestion charges when congestion occurs. The transmission customer may provide this information by indicating there transactions should be classified as firm or non-firm service. During the evaluation periods, transactions are either cut or congestion charges are assigned as congestion occurs. This includes real time operation. The combination of the financial offer and the willingness to pay congestion results in a bid stack for determining the next economic and available resource for increased demand or curtailment requirements. This provides for fair and non-discriminatory service to all transmission customers on a financial basis.

10.3.4 ATC in the Market System

ATC’s are a means for transmission providers to provide a reasonable indication of transfer capability available on the system to transmission customers. In addition the ATC process is used for a reservation process. The NYISO does not require transmission reservations. The purpose of ATC Posting in NY is to provide the Market with a reasonable indication of transfer capability available on the system based on the transmission interface flow utilization or existing transmission commitments based on the security constraint unit commitment evaluations.

10.3. ISO New England

10.3.1 Market Information

Within ISO New England there are 12 transmission providers who fall under FERC jurisdiction and who provide open access. They are:

- Bangor Hydro Electric Company (BHE)
- Central Maine Power Company (CMP)
- Central Vermont Public Service Company (CVPS)
- Citizen Utilities Company (CZN)
- Green Mountain Power Company (GMP)
- NEPOOL Regional Transmission Group (NRTG)
- Maine Electric Power Company (MEPCO)

- New England Power Company (NEP)/National Grid USA. It includes former Eastern Utilities Associates (Montaup) (EUA)
- Northeast Utilities System (NU)
- NSTAR - Former Boston Edison Company (BECO)
  - Former Cambridge Electric Company (CELC), and
  - Former Commonwealth Electric Company (COM)
- United Illuminating Company (UI)
- Vermont Electric Company (VELC)

Note: ISO New England provides administration services for the NRTG.

There are additional transmission providers with entitlements or ownership in the ties who are not FERC-jurisdictional. These include many of the owners of Highgate, Phase I, and Phase II ties to the Hydro-Quebec TransEnergie control area.

10.3.2 Transmission Access

Under the FERC approved NEPOOL Open Access Transmission Tariff (NOATT), the NRTG provides Regional Service as well as In, Out, and Trough services over the ties with neighbouring control areas, via the NEPOOL OASIS. There are two exceptions: First, In Service over the Highgate and Phase I/II ties with Hydro Quebec. These paths are posted by the owners of the facilities under their individual Tariffs and are posted on their individual OASIS. Second, services over the MEPCO-New Brunswick tie. This path is posted on the MEPCO OASIS. Non-discriminatory access for service is provided via TTC and ATC postings on the NEPOOL OASIS node, where customers can request reservations for service.

Note: ISO New England has filed NOATT revision with the FERC to eliminate IN SERVICE RESERVATIONS over the New York and MEPCO interfaces. Available In Service over these ties will be granted to transactions economically clearing the New England energy market.

10.3.3 Congestion Management

Until Congestion Management and Location Based Pricing is implemented at ISO New England, internal congestion is managed through re-dispatch measures and the associated costs are socialized. Congestion over the external ties is managed by curtailment of transactions according to FERC-approved tariffs in line with NERC principles, as well as grand fathered owner group arrangements when applicable. ISO New England acts as a dispatch authority for all tie transactions and for each tie curtailment procedures associated for that tie. Specific grand fathered scheduling and curtailment procedures exist for the following ties:

- Phase I and Phase II to Hydro Quebec
- Highgate to Hydro Quebec

10.3.4 ATC in the Market System

ATC in the planning horizon remains the same. ATC in the operating horizon: next hour and next day will be based on approved schedules only. Advance reservation will be eliminated, rather an implicit reservation will be posted on behalf of the actual schedules. ATC Posting will be based on these actual schedules and follow changes in Power System and Market System Conditions.

10.4. Québec

10.4.1 Market information

Within Québec there is 5 transmission providers that are:

- TransÉnergie (TÉ) a Hydro-Québec division, that is interconnected with NY, NE, Maritimes, Ontario, Maclaren, CRT and CFlCo
- Maclaren, that is interconnected with TÉ and Ontario
- Cedar Rapid Transmission (CRT), that is interconnected with TÉ, Ontario and New York.
- Churchill Falls Co. (CFlCo), that is interconnected with TÉ
- Alcan, that is interconnected with TÉ
- McCormick (LCHM), that is interconnected with TÉ.

None of them is under FERC jurisdiction but TÉ and CRT are providing Open Access to their system and Maclaren indicates its intention to provide Open Access.

10.4.2. Transmission Access

In Québec, open access is provided in conformity with the FERC Pro Forma Tariff and NERC standards. TTC and ATC are posted for the sake of offering physical reservations on their systems. Non-discriminatory access for service is offered via TTC and ATC postings on an OASIS node, where customers can request reservations for service.

10.4.3. Congestion Management

In Québec, congestion through Open Access Paths is managed on a non-discriminatory base by TransÉnergie who is the control area operator and system security coordinator for Québec area. Congestion is managed by curtailment of transactions according to FERC and NERC principles and TPs Open Access Tariffs. Transactions using non-firm transmission right are curtailed first. Transactions using firm transmission right, including native load, are curtailed after the transactions with non-firm transmission right and on a pro-rata base.

10.5. Maritimes

10.5.1. Market information

Within the Maritimes there are 5 transmission providers:

- NB Power, that is interconnected with NE, NSPI, TE, MECL EMEC and MPSC. (www.oasis.nbpower.com)
- Nova Scotia Power (NSPI), that is interconnected to NB Power only. (www.nspower.com)
- Maritime Electric (MECL), that is interconnected to NB Power only. (www.maritimeelectric.com)
- Maine Public Service (MPS), that is interconnected to NB Power only. (www.mfx.net/~mpstp/)
- Eastern Maine Electric Company (EMEC), that is interconnected to NB Power only. (www.emec.com)

NB Power, NSPI and MECL are all located in Canada and do not fall under FERC jurisdiction. EMEC and MPS are located in the United States and do fall under FERC jurisdiction.

10.5.2. Transmission Access

NB Power is the only transmission provider in the Maritime area that has interconnections external to the Maritime area. NB Power offers through, and out, access to its transmission system via its interconnections with neighbouring transmission providers (internal and external). TTC and ATC for these interconnections are posted on the NB Power OASIS to provide physical transmission reservations on their system.

10.5.3. Congestion Management

Congestion on the interconnections between NB Power and neighbouring utilities is managed on a non-discriminatory base by NB Power. Congestion is managed by curtailment of transactions according to FERC and NERC principles and NB Power's Open Access Tariff. Non-firm transactions are curtailed prior to firm transactions, with longer-term transactions taking precedence over shorter term ones. [Note - Firm transactions normally are curtailed on a pro-rata basis.]