NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
Princeton Forrestal Village, 116-390 Village Boulevard, Princeton, New Jersey 08540-5731

ATCT Drafting Team

Wednesday, November 16, 2005 11:00 a.m.–1:00 p.m. Eastern Time (U.S. & Canada).
Phone number 1(732) 694-2061
Conference code is 11161107

Conference Call Agenda

1. Attendance and Introductions — L. Middleton
2. NERC Antitrust Compliance Guidelines — B. Lohrman
3. Work Plan — L. Middleton
   a. ATC/TTC — Complete Reviews
4. Review Regional ATC/TTC/CMB/TRM documents
   a. WECC — http://www.wecc.biz/documents/library/procedures/ATC-apprdec01.pdf
   b. Entergy — https://www.entergytransmission.com/s/capability/AFC/AFCProcessManual.pdf
   c. FRCC — http://www.frcc.com/atcwg.htm
   d. SPP — http://www.spp.org/Publications/SPP_Criteria.pdf
5. Review Standards MOD-001 to MOD-009 in preparation for revisions
   a. http://www.nerc.com/~filez/standards/Reliability_Standards.html#Modeling,_Data,_and_Analysis
   b. ftp://www.nerc.com/pub/sys/all_updl/standards/sar/MOD-001_Rev_SAR_V1.pdf
   c. ftp://www.nerc.com/pub/sys/all_updl/standards/sar/MOD_Rev_SAR_V1.pdf
6. Reference Documents
   a. Comments on NERC SARs: ftp://www.nerc.com/pub/sys/all_updl/standards/sar/ATC_TTC_CBM_Standard_V1_Comments.pdf
   b. Comments to FERC NOI on ATC: http://www.nerc.com/~filez/standards/MOD-V0-Revision-RF.html

Item 2

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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NERC ANTITRUST COMPLIANCE GUIDELINES

I. GENERAL

It is NERC's policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

It is the responsibility of every NERC participant and employee who may in any way affect NERC's compliance with the antitrust laws to carry out this commitment.

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC's antitrust compliance policy is implicated in any situation should consult NERC's General Counsel immediately.

II. PROHIBITED ACTIVITIES

Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

Approved by NERC Board of Trustees, June 14, 2002
Technical revisions, May 13, 2005

III. ACTIVITIES THAT ARE PERMITTED

From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC's Certificate of Incorporation and Bylaws are followed in conducting NERC business. Other NERC procedures that may be applicable to a particular NERC activity include the following:

- Reliability Standards Process Manual
- Organization and Procedures Manual for the NERC Standing Committees
- System Operator Certification Program

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.

- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.

- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.

Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

Summary for Question # 1:

Is there a reliability need for the proposed standard?

- In general, most people felt that there is a reliability need for the proposed standard.
- Most of the parties that responded had no comments, however two that did comment felt that TTC and TRM were reliability quantities and that ATC and AFC were market quantities.
- Nearly all commented that yes there is a reliability need – Of the 14 that responded only four commented with any level of negative response, but just for ATC. These four stressed TTC is a reliability quantity and should be addressed.

ATCT DT – yes, ATCT DT – ATCT DT – believes that TTC/ATC are not reliability indicators, but are derived from reliability-based values, assumptions and criteria. However, there is a need to acknowledge the relationship between TTC and ATC values. The drafting team believes that both these quantities should be addressed by this reliability standard.

Commenter #1	• There is a reliability need for this standard especially as it pertains to TTC and TRM. Two parties believe that ATC and AFC are market quantities but there is no feed back from the other commenters one way or the other on this position. • Recommended analysis / reply of drafting team
Commenter #2	• Summary of submitted comment • Recommended analysis / reply of drafting team

FRCC	• ATCT DT – agrees
EXELON	• n/a

HYDRO QUEBEC TRANS ENERGIE	ATCT DT – believes that TTC/ATC are not reliability indicators, but are derived from reliability-based values, assumptions and criteria. However, there is a need to acknowledge the relationship between TTC and ATC values. The drafting team believes that both these quantities should be addressed by this reliability standard. The transparency of how ATC/AFC is derived is a market issue.
ONTARIO ISO	• na
ISO NE	
RTO/ISO Standards Review Committee	• na
MRO	Na
North Carolina Municipal Power Agenct Number 1	• na
ATC Task Force of NERC Planning Committee	• ATCT DT – agrees with the comment
Northeast Power Coordinating Council	ATCT DT – believes that TTC/ATC are not reliability indicators, but are derived from reliability-based values, assumptions and criteria. However, there is a need to acknowledge the relationship between TTC and ATC values. The drafting team believes that both these quantities should be addressed by this reliability standard. The transparency of how ATC/AFC is derived is a market issue.
NYISO	•

Southern Company Generation	•
Southern Company Transmission	•
WPS Resources	

Summary for Question # 02:

"Is the proposed scope of the standard sufficient to address reliability concerns; i.e. should the proposed standard include standardizing methods for the calculation of ATC, AFC, and TTC?"

- Of 14 responses, 6 were "yes", 6 were "no", and 2 were "yes and no". The majority of comments are in agreement, however.
- In general, most people disagree with the idea of a standard methodology for ATC/TTC/AFC calculation. NCMPA1 is the only exception.
- Nearly all commented about the need for increased data exchange, coordination, and documentation to promote transparency.

ATCT DT – yes, the drafting team believes that a single methodology should be developed within each RRO. The development of the methodology should be transparent and clearly documented. If options are provided in the regional methodology for a TSP crossing regional boundaries, the TSP must clearly document which option is being used.

FRCC	• No to one methodology, Yes to RRO (including RTOs/ISOs) standard methodology. • Standard should require RROs (including RTOs/ISOs) to develop regional methodolgy
EXELON	• No to one methodology. Certain aspects of the calculation must be required in the method, but one method should not be made standard. • Standard must state that aspects of the calculation critical to the reliability be required, i.e. exchange and use of data, monitoring all critical flowgates. What method the ATC calculator uses to incorporate these critical aspects is up to them.
HYDRO QUEBEC TRANS ENERGIE	• Proposed scope is already too detailed/prescriptive.

ONTARIO ISO	• No to one methodology. • Differences in methodologies may exist, but the processes must be coordinated and work together.
ISO NE	
RTO/ISO Standards Review Committee	• No to one methodology. • Differences in methodologies may exist, but the processes must be coordinated and work together.
MRO	
North Carolina Municipal Power Agenct Number 1	• Yes to one methodology •
ATC Task Force of NERC Planning Committee	• Further standardization of certain key elements is necessary • Standard must define certain key elements. NERC ATC and TTC methodology must be expanded to include and describe these key elements. Relationship of AFC to ATC and TTC, and how they are used and coordinated must be clearly defined.
Northeast Power Coordinating Council	• No to one methodology •
NYISO	• Standardization must recognize inherent differences between markets. • Coordination and documentation of calculation method would improve transparency.
Southern Company Generation	• No to one methodology • Standard should focus on increasing the transparency of study assumptions and methods. Standard should increase communication and coordination of transfer capability calculations.

Southern Company Transmission	• No to one methodology • Standard should focus on increasing the transparency of study assumptions and methods. No reliability need to mandate a prescribed detailed procedure for calculating TTC/ATC/AFC.
WPS Resources	

Discussion:
When a commenter refers to “standard methodology”, it is unclear if they are referring to a standard method for only Total Transfer Capability (TTC), Available Transfer Capability (ATC), or Available Flowgate Capability (AFC) or for all three.

Further, If they are referring to TTC it is unclear if they mean:

- How a specific parameter or set of parameters are used or derived (example A below)
- the ruleset for applying a study method (example B below)
- a set of “guiding principles” such as used in the SERC supplement IE1,IE2 (i.e.: TSP must include the following parameters in the calculation).

If they are referring to ATC or AFC, for most ATC is defined in pro-forma tariff, something example C below, and it is unclear if the reference is to a component of the equation or the equation itself.

Example A: The assumptions and parametersand used to create a study case or set of study cases, i.e.:

- Study period
- Dispatch method
- Load forecast
- Generation and Transmission outages
- Ambient rating corrections
- Partial path transactions
- Loop flows
- CBM, TRM implicit / explicit

Example B: The ruleset for executing a transfer capability study:

- Type of transfer (simultaneous, non-simultaneous)
- Cutoff
- Simultaneous transfer weighting
- Transfer test level
- Transfer type (gen-gen, gen-load, load-gen, load-load) for imports, exports, internal

Example C:

ATC = TTC – TRM – existing transmission commitments (including CBM)

AFC = Flowgate rating – Baseflow

Summary for Question # 3:

"Do you agree with the scope of the proposed standard?" referring to MOD-001-0 "Documentation of TTC and ATC Calculation Methodologies".

- In general, most people felt that the scope of the proposed standard was appropriate. A simple tally of the 14 Yes or No responses comes to 9 Yes, 4 No with one Yes and No. This question (#3) is related to the responses to question #2, and several responders to question #3 simply referred to comments in their response to #2.

- Most felt that standardization *of the particular method of ATC/TTC calculation (i.e. a prescriptive requirement)* was not necessary, although several felt that further standardization of certain coordination elements would improve and strengthen the ATC/TTC calculation process (from responses to question #2).

- Nearly all commented that………..(For question #3, few respondents had substantive comments.)

- And some asked for clarification on the applicability of any portion of a standard to either short-term or long-term (service as defined in FERC Order 888,889,638, etc.) TTC/ATC study methods.

Commenter #1 Excelon	• Agreed with scope, no additional comment. • Recommended analysis / reply of drafting team: None required.
Commenter #2 FRCC	• Agreed with scope, no additional comment. • Recommended analysis / reply of drafting team: None required.

Commenter #3 Hydro Quebec	• Responded "Yes and No", Commented that the standard should be limited to TTC/TFC for reliability purposes and ATC/AFC should be addressed by NAESB. • Recommended analysis / reply of drafting team: The responder apparently feels that only TTC and TFC are quantities that have reliability significance, while ATCs and AFCs are manipulated by differing market rules (from response to #1). The responder fails to recognize the relationship between the quantities. The calculation of TTC/TFC and ATC/AFC (because ATC/AFC are not independent of TTC/TFC, rather they are a subset of TTC/TFC) requires adherence to reliability standards (the purpose of this team), sound engineering principles and good utility practices which are not market rules that could be delegated to NAESB.
Commenter #4 Ontario ISO	• Agreed with scope, no additional comment. • Recommended analysis / reply of drafting team: None required..
Commenter #5 ISO NE	• Agreed with scope, no additional comment. • Recommended analysis / reply of drafting team: None required.
Commenter #6 RTO/ISO SRC	• . • Recommended analysis / reply of drafting team
Commenter #7 MRO	• Agreed with scope, no additional comment. • Recommended analysis / reply of drafting team: None required.

Commenter #8 N. Carolina MPA#1	• Responded "No". Commented that the scope should include standardized ATC/TTC/AFC calculations and required coordination between regions. • Recommended analysis / reply of drafting team: More standardization and greater coordination between regions is a global theme of the LTATF report and their recommendations and the primary goal of the drafting team. The LTATF also recognized, however that a prescriptive methodology would not be appropriate because regional and market model differences must be accommodated for a standard that will apply to all calculators. Rigid standardization of the process might have the undesirable effect of reducing currently available ATC/AFC by placing too much emphasis on the method, and too little on the many variables that can and should be considered, that are not the same everywhere. (Environmental considerations, for example.)
Commenter #9 ATC TF/NERC	• . • Recommended analysis / reply of drafting team
Commenter #10 NPCC	• Agreed with scope, no additional comment. • Recommended analysis / reply of drafting team: None required.
Commenter #11 NYISO	• . • Recommended analysis / reply of drafting team
Commenter #12 SOCO Gen	• . • Recommended analysis / reply of drafting team

Commenter #13 SOCO Transm.	• . • Recommended analysis / reply of drafting team
Commenter #14 WPS Resources	• Agreed with scope, no additional comment. • Recommended analysis / reply of drafting team: None required.

Summary for Question # 4:

"Are there aspects of the proposed standard you believe should be developed as a business practice
through NAESB?
Note: NAESB has a proposal for companion business practice - R05004)"

- Of 14 responses, 4 were "yes", 10 were "no".
- The common thread was that some aspects of the calculation should be developed as business practices by NAESB. There was one comment focused on the separation between business practices and reliability issues. A couple of entities indicated the need for CBM to be included in this standard and not in a business practice standard

EXELON	• No
FRCC	• No, but where necessary, business practices should be developed. However, such business practices should not address reliability issue • Certain aspects of every transfer capability calculation deal with market needs and may be better addressed via a business practice standard. The DT agrees that such efforts should not address reliability issues.
HYDRO QUEBEC TRANS ENERGIE	• Yes. ATC/AFC values are quantities required by the market and therefore should be defined by NAESB • To the extent the issues are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards.
ONTARIO ISO	• No
ISO NE	• No

RTO/ISO Standards Review Committee	• No
MRO	• No. There may be certain practices that should addressed by NAESB, but compliance with resulting standards must be voluntary. • To the extent the issues are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards. If a standard is defined, it must be adhered to; voluntary compliance is not an effective way of achieving industry-wide standardization.
North Carolina Municipal Power Agenct Number 1	• No
ATC Task Force of NERC Planning Committee	• Yes. Certain aspects of the AFC/ATC process need to be addressed by NAESB. Standards must focus on process, not the tools. Reliability issues must be handled by NERC. • To the extent the issues are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards. It is prudent to have standards define the process, not the implementation details.
Northeast Power Coordinating Council	• Yes. Market specific quantities should be addressed by NAESB. • To the extent the items are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards.
NYISO	• No

Southern Company Generation	• No. Would like to see CBM remain in this standard as it is an important component of grid reliability. CBM should not become a business practice standard. • CBM is addressed in a companion SAR on CBM/TRM.
Southern Company Transmission	• No. Would like to see CBM remain in this standard as it is an important component of grid reliability. CBM should not become a business practice standard. • CBM is addressed in a companion SAR on CBM/TRM.
WPS Resources	• Yes

Summary for Question # 5:

Do you agree with the list of entities to which the standard would apply?

- In general, most people felt that MOD-001-0 should apply to one or more additional entities.
- Most felt that standardization was … N/A
- Nearly all commented that the standard should apply to the Transmission Planner, Planning Authority, and Regional Reliability Organization.
- And some that asked for the standard to apply to the Transmission Owner and Reliability Coordinator.

Ron Falsetti Ontario – Independent Electricity System Operator	• No. Aspects of this standard would also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Kathleen M. Goodman ISO New England	• No. Aspects of this standard will also apply to Transmission Planner and Regional Reliability Organization. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.

Karl Tammar RTO/ISO Standards Review Committee	• No. Aspects of this standard would also apply to Transmission Planner, Transmission Owner, Planning Authority, RC and Regional Reliability Organization. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Ken Goldsmith Midwest Reliability Organization	• No. Aspects of this standard should also apply to Transmission Planner, Transmission Owner and Regional Reliability Organization. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Matt Schull North Carolina Municipal Power Agency Number 1	• Yes. • Recommended analysis / reply of drafting team: None.

Paul B. Johnson ATC Task Force of NERC Planning Committee	• No. Aspects of this standard also should apply to the Transmission Planner, Transmission Owner, Planning Authority, and Regional Reliability Organization. In those areas where Regional Transmission Organizations (RTOs), Independent System Operations (ISOs), or other agents, such as Transmission Service Coordinators (TSCs), are involved with ATC, TTC, and AFC calculations for multiple Regions or portions thereof, the role of these entities must be clearly defined. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Guy V. Zito Northeast Power Coordinating Council	• No. Aspects of this standard will also apply to Transmission Planner, Planning Authority and Regional Reliability Organization. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Mike Calimano NYISO	• Yes. • Recommended analysis / reply of drafting team: None.

Roman Carter Southern Company Generation	• No. RTO/ISOs should be required to provide the same documentation for their assumptions and methods. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Ronald Szymaczak Exelon	• Yes. • Recommended analysis / reply of drafting team: None.
John Odom FRCC	• No. This standard should also apply to the Planning Authority and the Reliability Regions. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Daniel Soulier, Victor Bissonnette Hydro-Quebec TransEnergie	• No. LSE, PSE, MO, PA, TP • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.

Marc M. Butts Southern Company Services	• No. While this SAR suggests that individual transmission owners and operators within an RTO or ISO may be exempt from developing and documenting a regional methodology for TTC/ATC/AFC determination, we expect that the RTO/ISO would not be exempt from clearly documenting their assumptions and methods. Maintaining this requirement will help to ensure the same transparency exists for the RTO/ISO footprint as in other regions. • Recommended analysis / reply of drafting team: RROs should be required to document their assumptions and methodologies. Drafting Team should discuss whether the standard applies to Transmission Planner, Transmission Owner, Planning Authority, Reliability Coordinator, Load Serving Entity, Purchase Selling Entity, or Market Operator.
Christopher Plante WPS Resources	• Yes. • Recommended analysis / reply of drafting team: None.

Summary for Question # 6:

Do you have any other terms that should be included in the definitions?

- Of 14 responses, 3 were "yes", 11 were "no".
- Most entities did not see the need for additional terms to be included in the standard. The ones that did see the need for new terms were mostly focused on better definitions for NATC and RATC.

EXELON	• No
FRCC	• No
HYDRO QUEBEC TRANS ENERGIE	• Yes. NATC & RATC, firm or non-firm should be defined by NAESB. Ultimate source and sink should be included in the NERC standard. • The sar will include definitions for these terms.
ONTARIO ISO	• No
ISO NE	• No
RTO/ISO Standards Review Committee	• No
MRO	• No.
North Carolina Municipal Power Agenct Number 1	• No

ATC Task Force of NERC Planning Committee	• Yes. Several terms need to be properly defined. • To the extent the issues are related to market needs and do not impact reliability, it would be appropriate for NAESB to define appropriate standards. It is prudent to have standards define the process, not the implementation details.
Northeast Power Coordinating Council	• Yes. NATC & RATC, firm or non-firm should be defined by NAESB. • The sar will include definitions for these terms.
NYISO	• No
Southern Company Generation	• No. Standard should contain consistent definitions.
Southern Company Transmission	• No.
WPS Resources	• No.

Summary for Question # 7:

Do you have any other data elements that should be included in the coordination and communication of the calculation of AFC/ATC/TTC?

- All responders felt that no other data elements should be included.
- One responder considers the proposed standard too onerous.

Exelon	• No
FRCC	• No
Hydro-Québec TransÉnergie	• The proposed standard is already unduly burdensome Response: No response required

Ontario - Independent Electricity System Operator	• No
ISO New England	• No
RTO/ISO Standards Review Committee	• No
MRO	• No
North Carolina Municipal Power Agency Number 1	• No
ATC Task Force of NERC Planning Committee	• No
Northeast Power Coordinating Council	• No
NYISO	• No
Southern Company Generation	• No
Southern Company Transmission	• No

WPS Resources	• No

Determination of Available Transfer Capability Within The Western Interconnection

June 2001

Rocky Mountain Operation and Planning Group
Northwest Regional Transmission Association
Southwest Regional Transmission Association
Western Regional Transmission Association
Western Systems Coordinating Council

CONTENTS

Determination of Available Transfer Capability Within the Western Interconnection

1. Introduction

Members of the Regional Transmission Groups (RTGs) and other entities in the Western Interconnection are obligated to provide information to their members and the public regarding Available Transfer Capability (ATC) for transmission paths, in accordance with National Electric Reliability Council (NERC) and Western Systems Coordinating Council (WSCC) standards, the Regional Transmission Group (RTG) Governing Agreements, the Federal Energy Regulatory Commission (FERC) Order 888 Open Access Tariffs, and FERC Order 889. In addition, NERC and FERC are looking for additional industry development of definitive methods for determining ATC.

Transmission Providers in the Western Interconnection will determine ATC in accordance with the NERC document "Available Transfer Capability Definitions and Determination". This Western Interconnection methodology document provides more detail and specific methodology for ATC determination based on commercial practices in the Western Interconnection. The methodology builds upon the Rated System Path based method that is used for determining Total Transfer Capability (TTC) in the Western Interconnection and is intended to fully comply with all NERC, WSCC, RTG and FERC rules regarding ATC. It provides additional details, principles, and reasonableness tests upon which a broad membership consensus has been reached. The Rated System Path Methodology is described in Appendix B of the NERC Report, "Available Transfer Capability Definitions and Determinations."

The Parties to this document acknowledge that given industry restructuring the California Independent System Operator (CaISO) and other future RTOs may have different operational protocols for calculating transmission availability. The CaISO is a non-profit public benefit corporation organized under the laws of the State of California. The CaISO is responsible for the reliable operation of a grid comprising the transmission systems of Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company. The CaISO, pursuant to its approved Tariff by the FERC, provides open and non-discriminatory transmission access to the market participants in its Day Ahead, Hour Ahead and Real Time Markets. Under that Tariff, CaISO follows different criteria for TTC, TRM and CBM allocations.

2. Methodology and Implementation

This document describes the Western Interconnection's regional practice and methodology for the determination of ATC. It is intended to be the Western Interconnection's standard reference document for the determination of ATC. This methodology is intended to be consistent with the requirements of NERC ATC standards. The use of ATC will be governed by the Transmission Providers' tariffs developed consistent with FERC published decisions, policies and regulations. Disputes between participants will be addressed through the process provided in the tariff or through other applicable dispute resolution processes (i.e., RTG, WSCC, other).

Each Transmission Provider's ATC methodology document shall be reviewed periodically by WSCC to ensure the procedures and practices described in their documents are consistent with the Western Interconnection ATC document and NERC standards as relates to reliability of the interconnected system. This periodic review shall not include the assessment of the Transmission

Provider's implementation of its transmission services tariff but shall verify reliability standards are observed while providing transmission services.

3. Applicability

This document and the methodology herein, apply to all members of the Parties in accordance with their governing authorities**.** Individual Transmission Provider variances from this methodology will be requested by the Transmission Provider and approved by the appropriate organization (FERC, Regional Transmission Association, or WSCC).

4. Scope

This document governs only the methodology for determination of ATC and required frequency for updating ATC. The obligation of participants to post ATC on an OASIS should be in accordance with FERC Orders 888 and 889 or their successor documents.

5. Purpose

The purpose of this document is to ensure consistent implementation within the Western Interconnection of the definition and determination of ATC. For the Members of these organizations, it is intended to supplement the WRTA Governing Agreement, NRTA Governing Agreement and SWRTA Bylaws (collectively, "RTG Governing Agreements"), which broadly define ATC and outline a method for requesting transmission service.

This document builds upon and supplements the rules, definitions, principles and processes delineated in the following:

- NERC Report on Available Transfer Capability Definitions and Determination (June 1996).
- NERC Report on Transmission Transfer Capability (May 1995)
- NERC Transfer Capability Margins Standard (proposed, add issue date when finalized*)*
- WSCC Procedures for Regional Planning Project Review and Rating Transmission Facilities (original dated March 1995)
- FERC Order 888 or successor documents (Open Access Tariffs) (original dated April 1996)
- FERC Order 889 or successor documents (Open Access Same-Time Information Systems) (original dated April 1996)
- Western Regional Transmission Association Governing Agreement (January 1995)
- Northwest Regional Transmission Association Governing Agreement (February 1995)
- Southwest Regional Transmission Association Bylaws (June 1995)
- Joint Transmission Access Principles (CCPG) (December 1991)

Summaries of any information contained in any of the documents listed above are not intended to imply any deviation from the contents of those documents.

6. Determination of ATC

The process for determining ATC for each Transmission Provider in a path should be reasonable, auditable and supportable. It consists of three steps: (1) the determination of path Total Transfer Capability (TTC), (2) the allocation of TTC among Transmission Providers, and (3) the determination of each Transmission Provider's Committed Uses. A Transmission Provider's ATC is then determined by subtracting Committed Uses from allocated TTC.

ATC = TTC (allocated) - Committed Uses

Using NERC ATC terminology,

Committed Uses = TRM + Existing Transmission Commitments (including CBM)

where TRM = Transmission Reliability Margin
CBM = Capacity Benefit Margin

For information on the determination of ATC and the related operating and planning relationships, refer to the NERC document, "Available Transfer Capability - Definitions and Determination" specifically the Sections entitled Determination of Available Transfer Capability, page 15, Commercial Components of Available Transfer Capability, pages 15 to 18, and Non-Recallable (Firm) and Recallable (Non-firm) Relationships and Priorities, pages 18 to 21.

ATC shall be calculated with the following frequencies:

- Hourly ATC for the next 168 hours: Once per day
- Daily ATC for the next 30 days: Once per week
- Monthly ATC for months 2 through 13: Once per month

Transmission Providers should use the best assumptions available for all TTC and ATC calculations. Calculations for hourly ATC within the current week should take into account the load variations during the day, any partial day outages, and best estimates of probable unscheduled flow and location of operating reserves. Daily calculations will use only peak loading for the day, and have to take into acount all partial day outages. Monthly calculations will use broader based assumptions such as monthly peak, accounting for all major outages during the month, and less specific estimates of unscheduled flow and location of operating reserves.

Generally in the Western Interconnection, netting of reservations and schedules cannot be used to increase firm ATC. There is one exception to this general rule which can be implemented on a case-by-case basis when the Transmission Provider, at its sole discretion, determines that they can do so without degrading system reliability. This exception can be invoked if there is firm load on one side of the path in question and the generation resources scheduled to serve it are on the other side of the path. Firm ATC across the path in the direction from the load to the generator can be increased by the scheduled amount from the generator to the load minus an adjustment for operating reserves and back up resources. This adjustment is determined by the location of the operating reserves and back up resources that would be deployed if the original resources serving the load were lost. Each application of this exception must be carefully analyzed based upon the specific circumstances before firm netting is employed. See Appendix I for an illustration and more details.

Parties seeking ATC on constrained paths should contact the Transmission Provider who will then work with generators on the Transmission Provider's system to assess its ability to make ATC available through redispatch and the costs associated with the redispatch, consistent with the Transmission Provider's tariff. If the constraint is related to a nomogram limitation, parties may utilize applicable nomogram market mechanism procedures.

6.1 Determination of Total Transfer Capability (TTC)

TTC represents the reliability limit of a transmission path at any specified point in time. It is a variable quantity, dependent upon operating conditions in the near term and forecasted conditions in the long term. TTC shall be calculated consistent with the requirements of FERC Orders 888 and 889 and as needed to represent system conditions, but no less frequently than seasonally. TTC cannot exceed the path rating. Within the Western Interconnection, a wide area approach is used to determine TTC on a path basis using the Rated System Path method discussed in WSCC's "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and NERC's "Report on Available Transfer Capability Definitions and Determination". The determination of TTC is required to conform with WSCC's "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and WSCC's "Minimum Operating Reliability Criteria". Specific system operating conditions (system topology, load/generation patterns, simultaneous path loadings, and facility outages) may require that TTC or TRM be adjusted to maintain system reliability.

TTC may sometimes be better defined by a nomogram, a set of nomograms, or a series of equations than by a single number, particularly when determining TTC values for two or more parallel or interacting paths. Where the simultaneous transfer capabilities of paths are limited by the interactions between paths, the Transmission Provider should make this known on the OASIS. This may be done by posting non-simultaneous TTC and subtracting TRM, where TRM includes the difference between non-simultaneous and simultaneous limits. As an alternative to computing TRM, the Transmission Provider may post non-simultaneous TTC and describe on the OASIS the nomogram and associated curtailment conditions. In either case, Firm ATC should be based on the best estimate of the simultaneous capability of the path during the period posted.

The total net schedules on a Path are not to exceed the Path TTC.

6.2 Allocation of TTC

When multiple ownership of transmission rights exists on a path or parallel/interacting paths, it is necessary to reach agreement on the allocation of those transmission rights in order to determine and report ATC.[1] A single TTC number, appropriate for the actual or projected condition of the transmission system, will be agreed upon for the path and this TTC will then be allocated between the Transmission Providers, to yield each Transmission Provider's share of the path's TTC for the ATC posting period.

If the Transmission Providers can't come to an agreement amongst themselves, the WSCC and the RTGs in the Western Interconnection provide several dispute resolution forums through which path rating and allocation issues may be addressed.

[1] The allocation rules may address allocations for both normal conditions and system outage conditions.

6.3 Determination of Committed Uses

This section describes the principles, practices and methodology for the determination of Committed Uses[2] in terms of the NERC components of TRM, Existing Transmission Commitments and CBM.

6.3.1 Principles for Determination of Committed Uses

This document adopts an approach for addressing the determination of Committed Uses.

The key to the successful implementation of this approach is development of specific principles, guidelines and reasonableness tests that will be used by Transmission Providers in making their assumptions and determinations of Committed Uses and will provide guidance for dispute resolution proceedings.

Transmission Providers will be expected to:

- Use reasonable, "good-faith" assumptions, consistent with general principles outlined in this document

- Make those assumptions and the underlying justifications for those assumptions available, in accordance with NERC and WSCC standards, the RTA Governing Agreements, FERC Order 888 and FERC Order 889 or their successor documents.

- Justify such assumptions and results, if called upon to do so, in applicable dispute resolution forums, (i.e. FERC 888 tariff process and RTG, WSCC or other dispute resolution processes).

- Adopt assumptions which are consistent with documented and consistently applied reliability requirements, including WSCC Minimum Operating Reliability Criteria, WSCC Power Supply Design Criteria, WSCC Reliability Criteria for System Planning, and the transmission provider's documented and consistently applied internal reliability criteria.

- Apply all assumptions comparably, non-discriminatorily and reasonably. A Transmission Provider's assumptions and methodologies, taken as a whole, must be consistently applied in the treatment of all Transmission Customers in a comparable and non-discriminatory manner.

[2] Committed Uses, as described in the RTA Bylaws, are composed of (1) native load uses, (2) prudent reserves, (3) existing commitments for purchase/exchange/deliveries/sales, (4) existing commitments for transmission service and (5) other pending potential uses of transfer capability.

- Use assumptions and methodologies that facilitates market participation, provided that the outcome meets transmission system reliability requirements and does not impose uncompensated transmission services costs on the Transmission Provider.

- A Transmission Provider's assumptions and methodologies for determining ATC must be consistent with the assumptions used by the Transmission Provider in other aspects of its business (for example, system planning).

6.3.2 Determination of Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure under a broad range of uncertainties in system conditions. TRM accounts for the inherent uncertainty in system conditions and system modeling, and the need for operating flexibility to ensure reliable system operation as system conditions change.

The benefits of TRM extend over a large area and possibly over multiple providers. TRM results from uncertainties that cannot reasonably be mitigated unilaterally by a single provider. In accordance with the terms and conditions of the Transmission Provider's tariff, TRM may be sold on a non-firm basis providing that reliability of the system is not jeopardized. TRM should not be sold as firm.

Each Transmission Provider should make its TRM values and calculation methodology publicly available. The TRM requirement should be reviewed and appropriate updates made by the TPs at a minimum prior to each Operating Season.

In the Western Interconnection methodology, firm ATC reductions associated with TRM may include the following components. TRM may be set to zero.

- Transmission necessary for the activation of operating reserves

- unplanned transmission outages (for paths in which contingencies have not already been considered in establishing the path rating)

- simultaneous limitations associated with operation under a nomogram

- loading variations due to balancing of generation and load

- uncertainty in load distribution and/or load forecast [3]

- allowances for unscheduled flow

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[3] Transmission Provider's allowances for load forecasts uncertainty may be part of TRM provided that: (1) the allowance is available as non-firm service on a comparable and non-discriminatory basis, (2) the allowance reduces the exposure to curtailments to all Transmission Customers with firm reservations on a prorata basis for unanticipated load, and (3) the allowance does not duplicate consideration of uncertainty within the load forecast itself.

Transmission capacity required to implement operating reserve sharing agreements for the period immediately following a contingency and before the market can respond (currently up to 59 minutes following the contingency) are included in TRM.

If the limitation on the use of TRM to 59 minutes would force a Transmission Provider to set aside unnecessary CBM on the same path as the TRM, that Transmission Provider may utilize the TRM beyond the 59 minutes. This would allow the Transmission Provider to maximize the ATC by not needlessly setting aside twice the amount of transmission (TRM and CBM) than is necessary for reliability.

TRM does not include allowances for planned outages and other known transmission conditions which should be included in the calculation of TTC. The Transmission Provider has the option of including the above described components of TRM in either the determination of TRM or TTC, but not in both.

Allowances for transmission contingencies should not be included in TRM for paths which have had an Accepted Rating established, since contingencies are already included in the determination of the Accepted Rating. A Transmission Customer with firm reservations which desires to reduce its risk of pro-rata curtailment must explicitly request a reservation of additional rights. Such rights cannot be reserved under the auspices of CBM or TRM. Where such reserved rights are not scheduled for use, the Transmission Provider is required to make such rights available to other transmission service requesters in accordance with FERC Order 888 rules or their successors.

Regarding nomogram operation, the purpose for applying TRM on paths which are governed by nomograms is to account for the uncertainty in capacity availability created by the existence of the nomogram. This is used to establish the amount of firm ATC the Transmission Provider can offer. The size of this TRM adjustment will vary based on specific circumstances. The Transmission Provider should consider such issues as the frequency which specific nomogram thresholds (such as loading levels on interacting paths, generation levels, ambient temperatures, etc.) are reached and the duration that those conditions exist when determining the TRM adjustment. In cases where an allocation of firm rights has been established between two paths related by a nomogram, the TRM reflects the difference between this firm allocation and the path's TTC. TRM set aside specifically for this nomogram adjustment should be offered as non-firm ATC.

Allowance for generation and load balancing and for uncertainty in load distribution and/or load forecast, should be determined through the use of power flow studies and/or historical operating experience. TRM should not include margin already afforded by the WSCC Reliability Criteria or otherwise accounted for in the determination of TTC.

Unscheduled flow may be handled in either of two ways, either of which is acceptable, provided that the methodology is applied consistently and non-discriminatorily:

- The path can be reserved up to its TTC, without factoring in any estimates of unscheduled flows. In such a case, when unscheduled flows materialize, accommodations and curtailments will be made consistent with the WSCC Unscheduled Flow Mitigation Plan.

- The path operator, using reasonable, auditable, supportable projections, may subtract sufficient transfer capability from TTC, as a component of TRM, to reduce the need to make curtailments associated with projected unscheduled flows.[4] This should be made available as Non-firm transfer capability in case unscheduled flow is less than anticipated.

One method of presenting TRM is to calculate it as a percentage of TTC. Uncertainties accounted for in TRM become more defined in the operating horizon as compared to the planning horizon. This is reflected in smaller TRM values in the operating time frame.

6.3.3 Determination of "Existing Transmission Commitments"

This section identifies those items to be included in the determination of "Existing Transmission Commitments".

- Reservations for Native Load Growth: Transmission Providers may reserve existing transfer capability needed for reasonably forecasted Native Load growth[5]. Transfer Capability reserved for Native Load growth must be made available for use by others until the time that it is actually needed by the Native Load.

- Where transmission service is reserved for a Network Resource which is a purchase by the Transmission Provider to serve Native Load customers, the reservation should reflect the terms of the purchase (if 50 MW may be scheduled in any hour, then 50 MW of transmission must be reserved for every hour). Where the reservation is made based on the Native Load reliability need, the Transmission Provider must determine the applicable hours of such reliability need based on its load and resource circumstances.

- Native Load Forecasts: ATC determination does not presume the existence of sanctioned forecasts by regulatory agencies, although a Transmission Provider may use such a sanction in arguing the reasonableness of its determination of Committed Uses. In making reservations for Native Load, adjustments may be made for near-term uncertainties (e.g. weather). Long-term forecasts may use both generic and contractually committed resources to meet native load requirements. Transmission Providers must use reasonable assumptions in determining Native Load requirements and make available those assumptions and the resulting conclusions, and be able to justify the reasonableness of those assumptions and the resulting conclusions, as well as their consistency with then-current FERC policies, in applicable dispute resolution proceedings.

- Approved Load Forecast: A publicly-approved load forecast or resource plan is one which has been approved, or reviewed and accepted, by a regulatory agency

[4] Note: the SWRTA Bylaws specifically permit the exclusion of transmission capacity needed to accommodate unscheduled flows, at levels consistent with the WSCC Unscheduled Flow Mitigation Plan. Making allowances for projected unscheduled flows based on assumptions that are appropriate for the time horizon of the ATC estimate would be consistent with making the best technical estimate of ATC, and would therefore be consistent with the NERC ATC report.

[5] See footnote 2.

that is independent of the Transmission Provider. If there is no regulatory-approved forecast/plan, the Transmission Provider may publish its own good-faith forecast/plan (for example, an official Loads & Resources plan). The Transmission Provider must also provide the assumptions, and the underlying justifications for those assumptions, used to develop the forecast/plan, in sufficient detail to permit interested parties to examine and challenge the reasonableness of the forecast/plan in an applicable dispute resolution forum.

Evidence supporting the contention that such a forecast/plan has been made in good faith includes a showing that the forecast/plan produced for the purposes of determining Committed Uses and ATC is consistent with the forecast/plan the Transmission Provider uses in its internal planning of other facilities or for processes distinct from those related to determination of Committed Uses. Where there are differences in the ATC methodology from the internal planning assumptions and criteria they must be explained and be subject to a finding of reasonableness in an applicable dispute resolution forum.

Long-term forecasts generally state a net out-of-area resource requirement, but may not break this requirement down by interconnection path/interface or by time-of-use period. The Transmission Provider may use his discretion to make this breakdown, provided the Transmission Provider uses good faith and provides the underlying justifications. Use of a Transmission Provider's own data, assumptions and contracts for service is probably the most reasonable solution that can be attained unless there is an RTG-approved or WSCC-approved area-wide resource database used by all parties posting ATC. The forecast should distinguish between committed and planned resource purchases.

- <u>Ancillary Services (required as a part of Native Load service)</u>: Transfer capability should be reserved under Native Load for those ancillary services required to serve Native Load. These include transfer capability required to supply load regulation and frequency response services. Ancillary services for Operating Reserves are covered under Section 6.3.4.

- <u>Reservations Beyond Reliability-Based Needs:</u> A Transmission Provider may reserve ATC for the import of power which is beyond the amount reserved for reliability needs of their Native Load customers, only to the extent permitted under the FERC's Order 888, or the Transmission Provider's own Open Access Transmission Tariff (OATT) and is otherwise consistent with the Federal Power Act and the FERC's applicable standards and policies then in effect.

  A Transmission Provider's merchant function may reserve transfer capability to serve the non-reliability needs of its customers; however, it is necessary to reserve such capacity pursuant to applicable Network and Point-to-Point OATT similar to any other transmission customer. The Transmission Provider may reserve ATC for the import of power which is beyond the amount reserved for the reliability needs of it's Native Load customers, only to the extent permitted under FERC's Order 888, or the Transmission Provider's own OATT, consistent with the Federal Power Act and the FERC's applicable standards and policies then in effect.[6]

Consistent with Order 888, or the Transmission Provider's own OATT, a Transmission Provider may reserve either Network or Point-to-Point transmission service for its own resources and power purchases designated to serve Network Load. A Transmission Provider may also use the point-to-point tariff to reserve Firm transmission service where it has not made a purchase commitment. It must take such Firm point-to-point transmission service for its uncommitted purchases under the same terms and conditions of the tariff as it offers to others.

- Existing Commitments: Committed Uses associated with existing commitments at the time of the ATC determination are permissible. Determinations for these types of Committed Uses must be made available and are subject to evaluation upon request and in applicable dispute resolution forums.

- Firm Transmission Reservations for Energy Transactions: Transfer capability for energy transactions that can reasonably be expected to be consummated, such as expected hydro conditions, can be a Committed Use for the Transmission Provider (including an affiliated merchant business) to the extent consistent with the reservation provisions of the approved tariff by purchasing firm point-to-point transmission service from available transfer capability. Such transfer capability can be reserved for expected energy transactions, but must be released for Non-firm uses on a scheduling basis if unused or as otherwise required in accordance with the reservation priorities provided in the Transmission Provider's tariff.

  Economy energy purchases (Non-firm purchases) by the Transmission Provider's merchant function can get service under secondary service for non-network resources on an as available basis at no additional "bookkeeping" charge (Section 28.4 of the FERC Open Access Transmission Tariff). If the Transmission Provider is using this service it should decrement Non-firm ATC for the purchase, but not Firm ATC. Firm point-to-point Transmission Service (PPTS) has reservation and curtailment priority over Secondary Service. Secondary Service has reservation and curtailment priority over Non-firm PPTS. Where the purchases are Firm and meet the requirements of a Network Resource, they qualify for a Firm transmission reservation and would be a decrement from the Firm ATC posting. To reserve Firm ATC for a Non-firm purchase or for where the Transmission Provider's merchant has not secured the purchase commitment or the purchase cannot otherwise qualify as a

[6] Order 888 provides: at page 172 when discussing Reservation of Transmission Capacity, "We conclude that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utilities current planning horizon:" at page 191 when discussing Use of the Tariffs by the Rights Holder, "In the case of a public utility buying or selling at wholesale, the public utility must take service under the same tariff under which other wholesale sellers and buyers take service;" at page 323 when discussing Reservation Priority for Existing Firm Service Customers, "The transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon;" and at page 342 when discussing Network and Point-to-Point Customers' Uses of the System, "However we do not require any utility to take service to integrate resources and loads. If any transmission user (including the public utility) prefers to take flexible point-to-point service, they are free to do so."

Network Resource, the Transmission Provider's merchant must make a reservation of Firm PPTS just like it was any other Transmission Customer.

- Reserving transfer capability over multiple paths to secure capacity for a future undefined resource or purchase: Transmission Providers that have uncommitted purchases or resources as part of their resource plan to serve native load can reserve transfer capability on multiple paths until the uncommitted purchase or resource is defined. In such a case, the Transmission Provider should note on the OASIS that multiple paths are being reserved. If a request for transmission service is received for which there is inadequate ATC as a result of a multiple path reservation, the Transmission Provider should have the first right of refusal for use of the path. If the Transmission Provider exercises this right on a particular path, it should release its reservation on the other (multiple) paths.

- Good Faith Requests: Capacity may be reserved as "existing transmission commitments" for "good faith requests" for transmission service received by a Transmission Provider in accordance with applicable FERC or RTG request for service policy. ATC is decremented as specified by applicable FERC or regional policy.

- Information to be Provided: The following lists the types of assumptions and data that could be used in support of the determination of Committed Uses. Transmission Providers should make available the information used in their calculation of ATC values.

  Far-Term Environment (>1 year)

  - Load forecast
  - Load forecast error (range)
  - Standard for serving load
  - Breakdown of use by path
  - Breakdown of use by Time of Use period
  - Hydro and temperature forecasts
  - DSM, interruptible load assumptions
  - Redundancy of reserved paths
  - Resource outage standards (G-1? G-2?)
  - Resource assumptions (high/low hydro...)
  - Forecasted outages
  - Unit deratings
  - Resource dispatch assumptions
  - Purchases or sales to external parties
  - Wheeling contracts, including listings of Points of Receipt, Points of Delivery, and associated transmission demands at each point.

  Near-Term Environment (<1 month)

  - Standard for probability of serving load
  - Load forecasts (range of temperatures, hydro forecast, etc.)

- Resource outage standards (G-1? G-2?)
- Forecasts of generation
- Short-term wheeling arrangements, including listings of Points of Receipt, Points of Delivery, and associated transmission demands at each point.
- Purchases and sales with external parties.

6.3.4 Determination of Capacity Benefit Margin (CBM)

CBM is the amount of firm transmission transfer capability reserved by Load Serving Entities (LSEs) on the host transmission system where their load and generation resources are located, to enable access to generation from interconnected systems to meet generation reliability requirements. CBM is a uni-directional quantity with identifiable beneficiaries, and its use is intended only for the time of emergency generation deficiencies. CBM reservations may be sold on a non-firm basis.

Reservations should be made according to the applicable Transmission Provider's tariff. The determination of CBM reservations according to this Section 6.3.4 is only for purposes of determining required transmission capacity for generation reliability and is not intended to address any payment obligations associated with such reservations.

Each Transmission Provider should make its CBM values and calculation methodology publicly available, including a description of the procedure for the use of CBM in an energy emergency. Actual usage of CBM should be posted by the Transmission Provider.

The following components and considerations should be included in the determination of CBM. CBM may be set to zero.

- Replacement Reserves :

  Transmission for restoring operating reserves following a generator contingency, generally confined to the time period extending beyond the current scheduling hour that are required above the operating reserve level and are needed to accommodate generation reserves consistent with generation reliability criteria are included in CBM. CBM is only an import quantity and is reserved to meet the Transmission Customer's own potential resource contingencies.

- Reservations of Transmission for Purposes Other than Energy Delivery:

  In certain cases, a Transmission Provider with statutory obligation to serve native load may desire to reserve transmission for purposes other than energy delivery - for example, to provide a path for the import of ancillary services (such as spinning reserves) from another control area; or to allow imports on a different path (in a case where a control area requires a certain amount of unscheduled transfer capability for stability reasons). Similar to reserve sharing arrangements, such reservations are legitimate Committed Uses by a transmission Transmission

Provider to the extent that they are associated with meeting native load reliability requirements (rather than being economics-driven).

- Reservations of additional transfer capability for resource contingencies must be based upon reasonable, publicly available assumptions subject to evaluation in applicable dispute resolution proceedings. The methodology for determining the amount of reserves must be consistent with prudent utility practice, must be clearly documented and consistently followed, must be applied in a non-discriminatory manner, and must be auditable.

- Generation Patterns and Generation Outages:

  Many generation patterns and forced generation outages occur in the power system. These, including the number of generator contingencies, may be considered when determining Committed Uses, to the extent that deductions from ATC associated with these uncertainties use assumptions that are consistent with the planning and service reliability criteria which the Transmission Provider (with native load requirements) uses in serving its customers.[7]

Allowance for CBM generation reliability requirements should be determined in one of two ways, namely (1) using a Loss of Load Expectation (LOLE) probability calculation, or (2) deterministic based upon the largest single contingency. An LOLE of 1 day in 10 years is recommended. This calculation is made using commonly accepted probabilistic generation reliability techniques. The calculation is performed on a monthly basis. The generation requirement is then converted to a CBM requirement for each interconnection based upon historical purchases at peak times, typical load flow patterns and an assessment of adjacent and beyond control area reserves. The generation reliability requirement is updated at least annually.

The CBM requirement should be reviewed and appropriate updates made by the TPs at a minimum prior to each Operating Season.

Individual Transmission Provider CBM Methodologies shall consider in the CBM requirement only generation directly connected to the TP's system being used to serve load directly connected to that system. Generation directly connected to the TP's system which is committed to serve load on another system or which is not committed to serve load on any system shall not be included.

Interruptible load shall be included in the determination of CBM requirements.

[7] As uncertainty in forecasts diminishes, a Transmission Provider must release transmission capacity in a manner that is consistent with prudent utility practice, clearly documented, and consistently followed, applied in a non-discriminatory manner, and auditable.

GLOSSARY

Accepted Rating: a path rating obtained through the WSCC three-phase rating process that is the recognized and protected maximum capability of the path.

Available Transfer Capability (ATC): a measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already-committed uses.

CCPG: Colorado Coordinated Planning Group under the umbrella of the Rocky Mountain Operation and Planning Group (RMOPG).

Capacity Benefit Margin (CBM): that amount of transmission transfer capability reserved by Load-Serving Entities with generation on the system up to the purchased/owned amount of transmission, to ensure access to generation from interconnected systems to meet generation reliability requirements.

Committed Uses: Five committed uses described in the RTG Governing Agreements as described in this document.

Curtailability: the right of a Transmission Provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide the transmission service. Transmission service can be curtailed as per the Transmission Providers OAT or contracts.

Firm Transmission Service: transmission service which cannot be interrupted by the Transmission Provider for economic reasons, but that can be curtailed for reliability reasons. This service is known as Non-Recallable transmission service in the NERC ATC documents.

Load Serving Entity: an entity located within a Transmission Provider's system whose primary function is to provide energy to end use customers. Also known as Energy Service Providers.

Native Load: existing and reasonably-forecasted customer load for which the Transmission Provider - by statute, franchise, contract or regulatory policy - has the obligation to plan, construct or operate its system to provide reliable service. For Transmission Providers not operating in a Retail Access environment, Native Load refers to the load within a Transmission Provider's service territory, to which it is also obligated to provide energy. For Transmission Providers operating in a Retail Access environment, Native Load refers to the load within the Transmission Provider's service territory, independent of the Energy Service Provider(s) serving energy to the load.

Network Resources: Designated resources used by a Transmission Customer to provide electric service to its Native Load consistent with reliability criteria generally accepted in the region.

Non-firm Transmission Service: transmission service which a Transmission Provider has the right to interrupt in whole or in part, for any reason, including economic, that is consistent with FERC policy and the provisions of the Transmission Provider's transmission service tariffs or contract provisions. This service is known as Recallable transmission service in the NERC ATC documents, or service offered on an as-available basis where a higher priority service requester may displace a lower priority service requester under the terms and conditions of the pro-forma tariff.

NRTA: Northwest Regional Transmission Association.

Operating Season: Those seasons that WSCC requires Operating Transfer Capability Studies to be performed (winter, spring and summer).

Parties: Colorado Coordinated Planning Group, Northwest Regional Transmission Association, Southwest Regional Transmission Association; Western Regional Transmission Association, and Western Systems Coordinating Council.

Recallability: the right of a Transmission Provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the provisions of the Transmission Provider's transmission service tariff or contract provisions.

RTG Governing Agreements: Northwest Regional Transmission Association Governing Agreement, Southwest Regional Transmission Association Bylaws, and the Western Regional Transmission Association Governing Agreement.

SWRTA: Southwest Regional Transmission Association.

Total Transfer Capability (TTC): the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post- contingency system conditions.

Transmission Customer: Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. (FERC Definition – 18 CFR 37.3).

Transmission Provider: Any party that owns, controls, or operates facilities used for the transmission of electric energy in commerce.

Transmission Reliability Margin (TRM): that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

WRTA: Western Regional Transmission Association.

WSCC: Western Systems Coordinating Council

APPENDIX I

Standard for the Use of Netting for Firm ATC Calculations

In general, netting cannot be used to increase firm ATC. There is one exception to this general rule which can be done on a case-by-case basis at the Transmission Provider's discretion, provided that the criteria discussed below are adequately addressed.

If there is firm load on one side of the path in question and the generation resources scheduled to serve it are on the other side of the path, then firm ATC (and associated schedules) in the direction from the load to the generator can be increased by the scheduled amount from the generator to the load minus an adjustment for operating reserves and backup resources. This adjustment is determined by the location of the operating reserves and back up resources that would be deployed if the original resources serving the load were lost.

Any operating reserves or back up resources located on the same side of the path as the original resources maintain the firm counter-schedule, so the ATC in the direction from the load to the generator does not have to be decremented. If the operating reserves or back up resources come from the same side of the path as the load, then the counter-schedule would be lost. The ATC must then be decremented by the amount of these operating reserves and back up resources.

Each application of this exception must be analyzed carefully based upon the specific circumstances before firm netting is employed. A number of factors must be taken into consideration to determine how much of this firm netting can be reasonably allowed over any given transmission path. The factors that must be taken into account when determining the amount of load to net against include:

1. The size of the load. For firm netting, a forecast minimum load level that is reasonable for the time period under consideration should be used. The Transmission Provider must base the firm ATC calculations in these circumstances on a load level that can be expected to be present for the duration of any transactions that are netted against it.

2. Diversity of the load. Is the load a single large load that could be subject to interruption or is the load a diverse load area that has minimal risk of being completely blacked out?

3. Internal generation. Does the load area contain embedded generation resources?

4. Location of operating reserves and back-up resources. If the resources that are serving the load are lost, where will the operating reserves and back-up resources used to replace that generation come from? If they come from the same side of the path as load, then the counter-schedule is lost and there is the possibility that the path could be over-scheduled. Also, the reserves must be able to be deployed fast enough so that WSCC reliability standards for getting actual flows back within transfer limits are met.

Other factors may also need to be taken into account depending on the specific circumstances.

Example of Firm Netting Application:

Assume a path has a transfer capability of 1000MW in the east to west direction.
Assume that there is an actual load of 150MW on the east side of the path and 150MW of generation on the west side of the path that is used to serve it.
Firm east to west transactions of up to 1150MW can be accommodated across the path in the east to west direction since the load "nets out" 150MW due to the firm counter-schedule of the resource used to serve it in the west to east direction.

Approved at the October 25-26 WMIC meeting by WMIC.

Approved at the December 6, 2001 BOT meeting.

Item 4bi

Entergy Services, Inc.

As Agent for

Entergy Arkansas, Inc.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.

AFC PROCESS MANUAL

Effective Date: September 28, 2005

Revision: 1.1

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1 Introduction to the AFC Process

1.1 What is Available Flowgate Capacity (AFC)?

Entergy uses a flow-based approach for calculating available transfer (transmission) capability and to evaluate requests for transmission service under the Entergy OATT. A flow-based approach predicts and analyzes flows on constrained facilities (called "flowgates") when determining whether sufficient capacity exists to approve a transmission service request. This flow-based approach is an alternative to a contract path-based approach.

The AFC value for a particular flowgate is the amount of transfer capability over that flowgate that remains available for additional transmission service reservations above and beyond existing uses of the transmission system. Entergy calculates Firm AFC and Non-Firm AFC pursuant to established NERC formulas for evaluating transfer capability.

1.2 Applying a Flow-Based Approach on the Entergy Transmission System

The flow-based approach applies only to short-term transmission service requests that fall within an eighteenth-month calculation horizon. Short-term transmission service requests that fall outside of the eighteen-month calculation horizon are evaluated using the System Impact Study process under the Entergy OATT. The term "short-term transmission service" refers to the following types of transmission service offered under the Entergy OATT: (1) firm and non-firm point-to-point transmission service reserved in daily, weekly, or monthly increments for a duration of less than one year; (2) requests by existing network customers to designate new network resources in daily, weekly, or monthly increments for a duration of less than one year; and (3) requests by existing network customers to designate secondary (non-firm) resources in all increments and durations. Long-term transmission service requests continue to be evaluated using the System Impact Study process under the Entergy OATT.

Implementation of the AFC process on Entergy's system consists of the following elements:

1. <u>Flowgate Selection</u>: Entergy will first determine the set of transmission facilities or "flowgates" that will be monitored in the AFC process. Over time, flowgates may be added or removed from the initial set on either a permanent or temporary basis as described in the OATT and this manual.

2. <u>Calculation of AFC Values</u>: Using base case power flow models, the OASIS Automation software calculates an AFC value for each flowgate monitored as part of the AFC process. The AFC value is the amount of transfer capability over a particular flowgate that remains available for additional transmission service reservations above and beyond existing uses of the transmission system. The

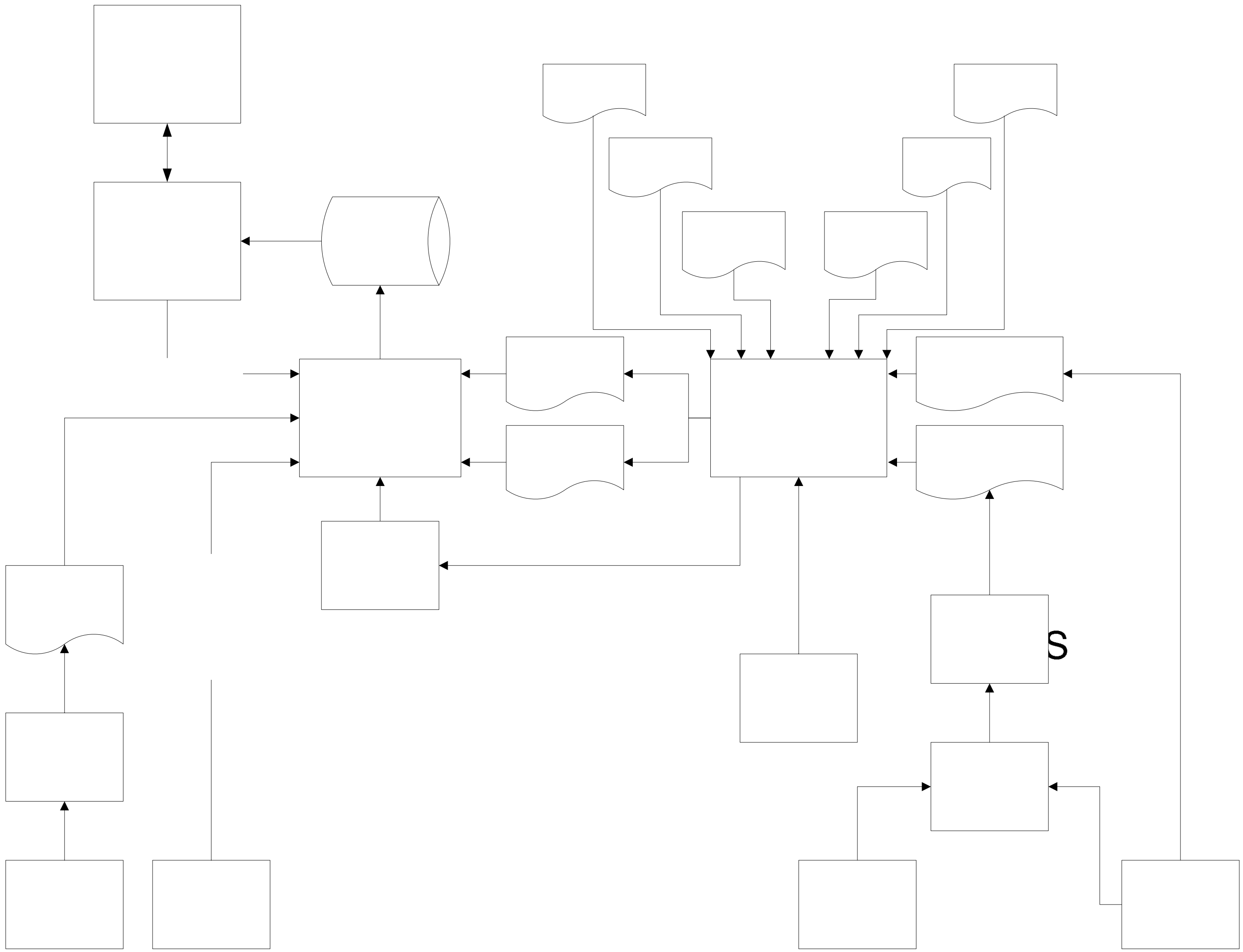
base case power flow models will reflect network information from the EMS platform, unit commitment data, load forecast data, outage information and reservation/schedule data, among other inputs. Depending on the time frame in question, the models will be based on real-time EMS models and data from the State Estimator or off-line planning models.

3. Response Factors: In order to evaluate whether a particular service request will use all, some, or none of the AFC for a particular flowgate, Entergy uses RFCalc, real-time EMS models and off-line planning models to calculate Response Factors. The Response Factors measure the power flow impact that each source-to-sink transaction has on each flowgate.

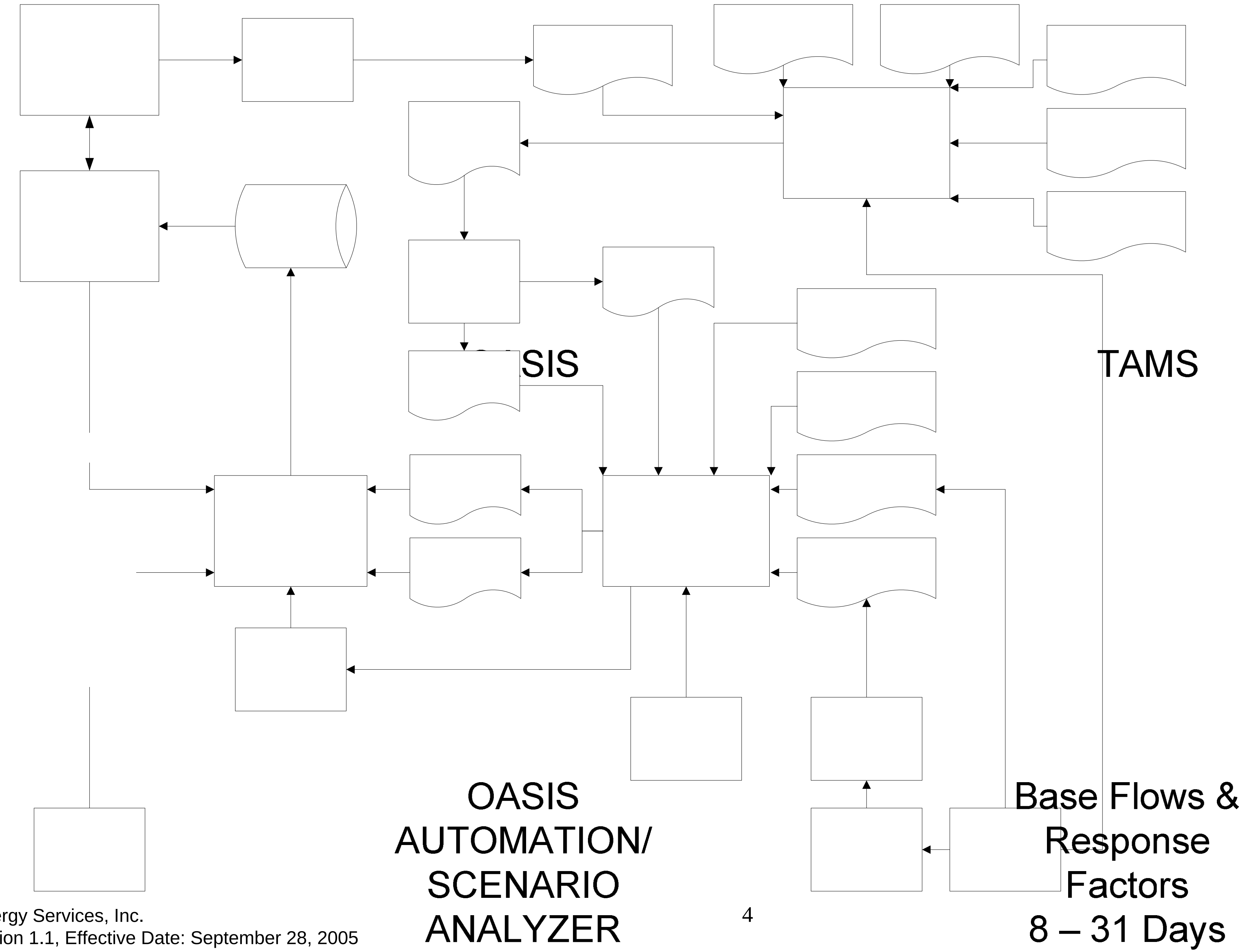
4. Time Horizons: The AFC process described above will be performed in three different time frames, referred to as ‘horizons.’ The Operating Horizon covers the time frame when firm service is scheduled, *i.e.,* all hours of the current and, after 12 p.m. all hours of the Day 2. The Planning Horizon covers the time frame starting from the end of the Operating Horizon extending out to Day 31. The Study Horizon covers the time frame from Month 2 – 18.

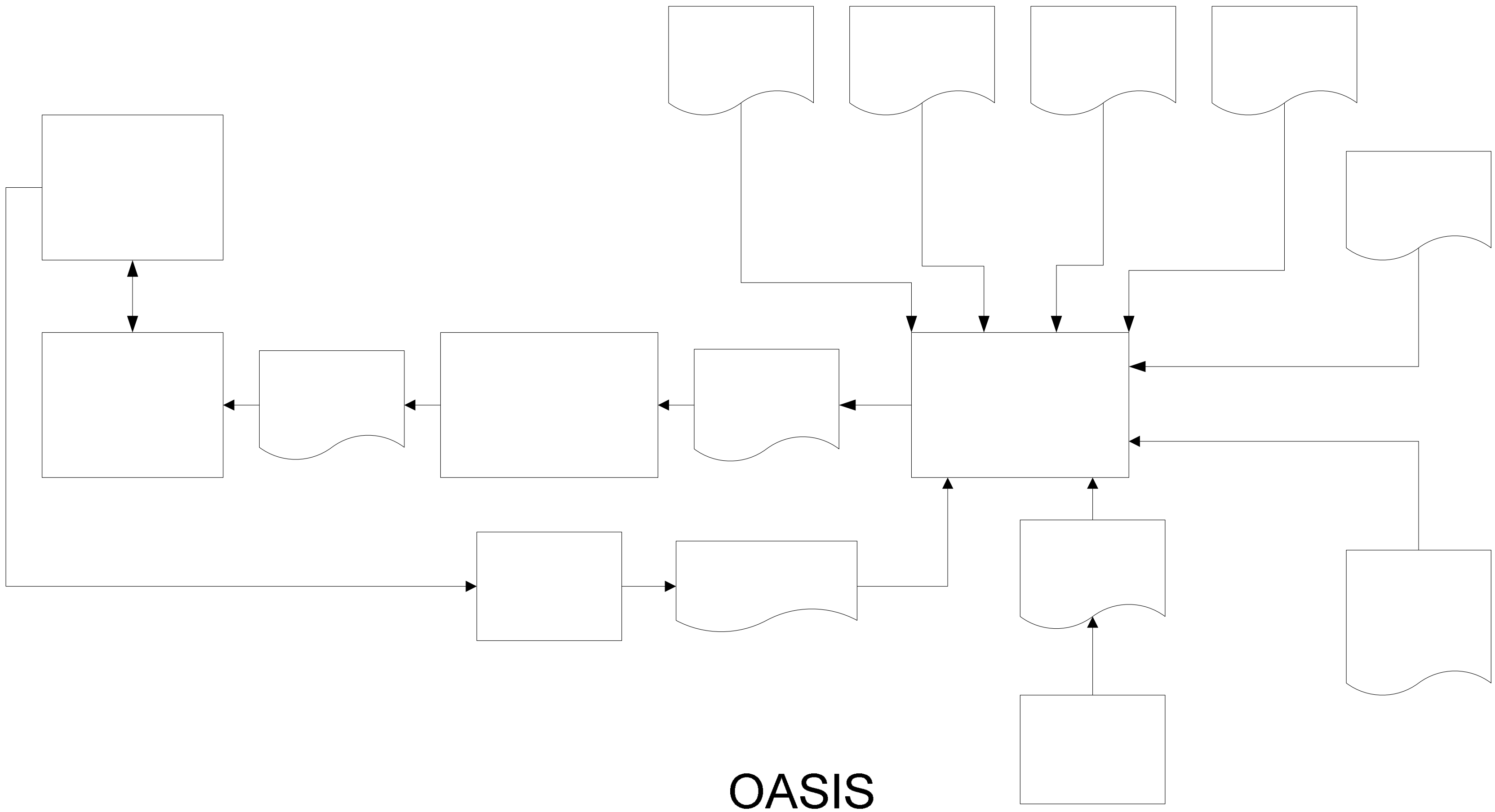
5. Evaluation of Service Requests: As individual transmission service requests are received, OASIS Automation applies the Response Factors to determine the impact new requests will have on the most limiting flowgates. Although the AFC process will monitor approximately 300-500 flowgates, a more limited set of flowgates will be used to evaluate individual service requests. When evaluating individual service requests, Entergy will only consider those flowgates that are: (1) “significantly impacted” by the request at issue, *i.e.,* those flowgates with a Response Factor equal to or greater than 3%; and (2) the “most limiting flowgates” for the request at issue, *i.e.* the fifteen flowgates with the lowest effective ATC values. If the effective ATC value on all of these flowgates remains positive or equal to zero after taking into account the impact of the transmission service request, the request will be granted. If the effective ATC value on any of these flowgates becomes negative or otherwise exceeds the rated capability of the facilities in question, then the request will be denied, unless transmission service of a lower priority may be preempted to bring the effective ATC value back to zero or positive.

1.3 AFC Process Flowchart



OASIS


OASIS
TAMS
OASIS
AUTOMATION/
SCENARIO
ANALYZER
Base Flows &
Response
Factors
8 – 31 Days


OASIS

Applications

Application	Purpose	Runs	Inputs	Outputs
AFC SDF	Retrieves Transmission Branch and Section Outages from AORS (Planned) and COS (Unplanned). The application produces a formatted file that is sent to the EMS servers where RFLOADER uploads the information into EMS OUTAGE SCHEDULER	Every Hour	AORS and COS	AFC_OUTAGES.csv
AORS	This application is used within the TRANSMISSION Outage Planning Process. Contains all planned Branch/Section and Equipment Outages for the Entergy Transmission System	Constantly	Outage Planning Process	See AFC SDF
COS	This application is used to report all outages on the Entergy Transmission System.	Constantly	Outage Reporting Process	See AFC SDF
OVERLORD FTP	Monitors a folder for a new file from AFC SDF and ftp-ed the file to the EMS Servers once the file appears. We must FTP the file to the EMS servers (instead of mapping between servers) because of security issues between the Corporate and EMS network.	Constantly	See AFC SDF	See AFC SDF
RFLOADER (Oper. & Planning Horizon)	Uses information from Entergy SPO and CLECO to produce the Unit Commitment and Load Forecast File for RFCALC. Also, RFLOADER loads outage information into EMS Outage Scheduler for RFCALC's use.	Every Hour	CLEC_UC.csv 110_UC.csv ZONAL_IMPORT_ LIMITS.txt PF_FACTORS.csv CLEC_LF.csv 110_LF.csv AFC_OUTAGES.csv	RFCALC_UC.csv RFCALC_LF.csv Populates EMS OUTAGE SCHEDULER

			APPEND_AFC_ OUTAGES.csv EMS RFLOADER DATABASE	
RFLOADER (Study Horizon)	Uses UC and LF information from PTI PSS/E solved power flow models to produce the Unit Commitment and Load Forecast File for RFCALC. Also, RFLOADER loads outage information into EMS Outage Scheduler for RFCALC's use.	Every Hour	UC.csv ZONAL_IMPORT_ LIMITS.txt PF_FACTORS.csv LF.csv AFC_OUTAGES.csv APPEND_AFC_ OUTAGES.csv EMS RFLOADER DATABASE	RFCALC_UC.csv RFCALC_LF.csv Populates EMS OUTAGE SCHEDULER
RFLOADER DATABASE	Used to store information on which generator units are on AGC and what units are within the WOTAB and AMITE SOUTH load zones.	Constantly	Information provided by Transmission Operational Planning	Static Information used by RFLOADER to perform its operations
EMS OUTAGE SCHEDULER	This application is used to store Outage data for use by RFCALC. The interface to insert data into EMS OUTAGE SCHEDULER was more trivial than interfacing directly to RFCALC to provide outage data. Since EMS OUTAGE SCHEDULER and RFCALC already had an interface, EMS OUTAGE SCHEDULER was utilized to provide current outage information for AFC calculations.	Constantly	AFC_OUTAGES.csv APPEND_AFC_ OUTAGES.csv	Provides interface to RFCALC for outage information
RFCALC	Calculates Base Flows and Response Factors on Entergy's Defined Flowgates.	Every Hour/Every six hours	RFCALC_UC.csv RFCALC_LF.csv EMS OUTAGE SCHEDULER RFCALC_NET_SCH.csv NETMOM Transmission	Base Flows & Response Factors provided to OASIS AUTOMATION.

			System Model Information NETMOM Asset Parameters Information NETMOM Current Equipment Status Information OASIS AUTOMATION's Reservation Information	
EMS NETMOM DATABASE	Part of AREVA's Network Applications and is used to define the Transmission System model and parameters (i.e. impedance). Along with the system network topology structure, the NETMOM Database provides current equipment status from SCADA to be used in hours 1 to 3 to determine system network configuration in these hours.	Constantly	Network Modeling Process	NETMOM Transmission System Model Information NETMOM Asset Parameters Information NETMOM Current Equipment Status Information
ROBOTAG	Entergy's application for managing the NERC Tagging Processes. Provides the scheduling information against firm reservations.	Constantly	NERC Tagging Process	Scheduling Information provided to TAMS
TAMS (Hours 1 – 168)	Entergy's application for storing Reservation information. Transmission Planning uses this reservation data to create PTI PSS/E power flow models.	Constantly	OASIS Reservation Information	Provides Reservation Data spreadsheet used by Transmission Operational Planning to create PSS/E power flow models.
TAMS (Day 8 – Study Horizon)	Entergy's application for storing Reservation information. Interfaces to Robotag to provide scheduling information against firm reservations.	Constantly	OASIS Reservation Information	RFCALC_NET_SCH.csv
OASIS AUTOMATION/ SCENARIO ANALYZER	Entergy application for manage the Transmission Request Process. Scenario Analyzer is used by marketers to check for the availability of Transmission Capacity.	Constantly	OASIS Reservation Information	Provides Reservation Information to RFCALC

OASIS	The application marketers use to receive information on Entergy's Transmission System and submit Transmission Capacity Requests (Reservations).	Constantly	Transmission Information Postings Transmission Request Submissions	Reservation Information
PTI PSS/E	Power Flow Modeling application used to create power flow models for Entergy Transmission's Daily models.	Daily	Entergy SPO's Weekly Unit Commitment, Load Forecast and Generation Outages Plan Entergy SPO's Monthly Unit Commitment, Load Forecast, and Generation Outage Plan AORS Planned Transmission Outages MAXLS.xls	Daily Base Cases (Power Flow solutions)
UC AUTO	Extracts Unit Commitment and Load Forecast Information from PTI PSS/E Base Cases files to provide to RFLOADER	Daily	PTI PSS/E Daily Base Case Solutions	UC.csv LF.csv
PAAC OFFLINE CALCULATOR	Uses PTI PSS/E solved power flow models to produce flow gate base flows and response factors for the Study Horizon months.	Weekly	PSS/E Monthly Base Case Solutions	Flow gate Base Flows and Response Factors file that will be uploaded by OASIS Automation

Inputs/Outputs

Input/Output	Purpose	Produced	Provided By
CLEC_UC.csv	Provides information on Unit Commitment for CLECO generators for 1 to 168 hours	Daily	CLECO
CLEC_LF.csv	Provides information on Load Forecast for CLECO	Daily	CLECO
110_UC.csv	Provides information on Unit Commitment for Entergy SPO's network generators for 1 to 168 hours	Daily, updated when changes occur.	ENTERGY SPO
110_LF.csv	Provides information on Load Forecast for ENTERGY and AECC Network Load for 1 to 168 hours	Daily, updated when changes occur.	ENTERGY SPO

ZONAL_IMPORT_LIMITS.txt	Provides information on Import Limit to the WOTAB and AMITE SOUTH load zones along with a percentage of Entergy's Load that WOTAB and AMITE SOUTH constitute	Daily	TRANSMISSION OPERATIONAL PLANNING
PF_FACTORS.csv	Provides generator participation factors for 1 to 168 hours and 8 to 31 days that is included in the RFCALC_UC.csv file.	Daily	TRANSMISSION OPERATIONAL PLANNING
AFC_OUTAGES_append.csv	Equipment, External Control Areas, and Generator Outages that cannot be obtained through AORS or COS	Daily	TRANSMISSION TECHNOLOGY DELIVERY
AFC_OUTAGES.csv	Transmission Branch/Section , Auto Transformer outages that are planned (AORS) and unplanned (COS)	Hourly	AFC SDF
RFCALC_NET_SCH.csv	Aggregation of Schedule Information by hour and OASIS Source/sink that use Firm Transmission Reservations. Information only for Operational Horizon hours.	Hourly	TAMS
RFCALC_UC.csv	The Unit Commitment file required by RFCALC that is created by RFLOADER from UC inputs.	Hourly	RFLOADER
RFCALC_LF.csv	The Load Forecast file required by RFCALC that is created by RFLOADER from LF inputs.	Hourly	RFLOADER
Entergy SPO Current Week Unit Commitment and Load Forecast Plan	Provides daily information on Unit Commitment and Load Forecast for Entergy SPO's network generators and load for the next 7 days via a security web site.	Daily, updated when changes occur.	ENTERGY SPO
Entergy SPO Current Week Generator Outages Plan	Provides daily information on Generator Outages for Entergy SPO's network generators for the next 7 days via a security web site.	Daily, updated when changes occur.	ENTERGY SPO
Entergy SPO Monthly Energy Plan Unit Commitment and Load Forecast Plan	Provides information by week on Unit Commitment and Load Forecast for Entergy SPO's network generators and load for the next month via an excel file	Monthly	ENTERGY SPO
Entergy SPO Monthly Energy Plan Generator Outages Plan	Provides information by week on Generator Outages for Entergy SPO's network generators for the next month via an excel file.	Monthly	ENTERGY SPO
MAXLS.xls	Provides information on Unit Commitment for Entergy's Hydro Units.	Weekly	ENTERGY SPO

TAMS Reservation Data	A file of reservations from OASIS that need to be modeled into the PSS/E power flow models	Daily for Oper/Planning Weekly for Study	TAMS
AORS Outage Data	A file of outages from the approved planned outages in AORS	Daily	AORS
PSS/E Base Cases	The results of a solved power flow model from PTI PSS/E	Daily	PTI PSS/E
LF.csv	An extraction of Load Forecast information for the solved PTI PSS/E power flow solutions	Daily	UC AUTO
PF_FACTORS.csv	Provides generator participation factors for 1 to 168 hours and 8 to 31 days that is included in the RFCALC_UC.csv file.	Daily	TRANSMISSION OPERATIONAL PLANNING
APPEND_AFC_OUTAGES.csv	Equipment, External Control Areas, and Generator Outages that cannot be obtained through AORS or COS	Daily	TRANSMISSION TECHNOLOGY DELIVERY
Entergy SPO Monthly Load Forecast	Provides the Load Forecast for Entergy SPO's network load	Yearly	ENTERGY SPO
SMEPA Monthly Load Forecast	Provides the Load Forecast for SMEPA's embedded network load	Yearly	SMEPA
ETEC Monthly Load Forecast	Provides the Load Forecast for ETEC's embedded network load	Yearly	ETEC
LAGN Monthly Load Forecast	Provides the Load Forecast for LAGN's network load	Yearly	LAGN
Entergy SPO Monthly Generator Outage Plan	Provides the generation outage plan for Entergy SPO's network generators	Updated when changes occur	ENTERGY SPO
Planned Transmission Outage Data	A file of outages from the approved planned outages in AORS	Monthly	AORS
SEAMS Models	A collaborative effort between Entergy and External Control Areas to produce in PSS/E an extensive model of the SERC interconnection, with monthly updates to Southern Company and Tennessee Valley Authority control areas	Monthly	TRANSMISION OPERATIONAL PLANNING
Monthly PSS/E Base Cases	The results of a solved power flow model from PTI PSS/E	Weekly	PTI PSS/E
Base Flows & Response Factors 2 – 18 Months	The results of the PAAC OFFLINE Calculator used to by OASIS Automation to publish AFC values.	Weekly	PAAC OFFLINE Calculator

2 Criteria for Flowgates and Transmission Facilities

2.1 Criteria for Selecting Flowgates to Monitor

Entergy's AFC process will determine constrained facility ATC by monitoring the impact of transmission service requests on certain specified "flowgates." A "flowgate" represents a constrained transmission facility that exceeds 100% of its rating during a power transfer. A "flowgate" can be either: (1) a single transmission facility, referred to as a "monitored element"; or (2) a set of transmission facilities that includes "monitored elements" and "contingent elements." Entergy will maintain a "Master List" of all monitored flowgates and that list will be posted on OASIS. The current list of monitored flowgates is publicly-available at: https://www.entergytransmission.com/s/capability/AFC/AFC_Flowgatelist_posting.asp

Entergy uses the following assumptions for its selection of flowgates:

- 100% loading of the transmission facility rating for normal operation;
- 100% loading of the transmission facility rating during first contingency conditions;
- To maintain reliable system operations, Entergy attempts to maintain a minimum voltage of 92% under contingency conditions at all transmission stations. This threshold is higher for EHV stations (230 kV and above) and varies from 92% to 96%;
- Fault current thresholds are not a factor in determining the list of flowgates for AFC calculations; and
- For facilities limited on stability, 100% of the rating of a transmission facility for normal operation based upon stability studies. Stability studies are performed by the transmission planning group to determine stability constraints. The results are translated, where applicable, to a flowgate flow limit for modeling in short-term models used for AFC analysis. Entergy applies a set of criteria for evaluating stability issues which are based existing industry standard practices.

For the initial determination monitored flowgates, the criteria include, but are not limited to: a threshold of 3% OTDF and a violation of 100% of a facilities' highest nameplate rating under first contingency. To select the flowgates that will be monitored in the AFC process, Entergy focuses on those transmission facilities that are likely to exceed 100% of its rating during power transfers. Entergy uses criteria based upon NERC Standard I.A. and the Southeastern Electric Reliability Council's ("SERC") supplement to that standard to define when a transmission facility exceeds 100% of its rating. For the initial determination of whether a facility met the NERC criteria, Entergy reviewed its existing power flow studies, including GOL studies, TTC/ATC studies, system impact studies and studies performed in the real time environment. These studies were performed by using a base case power flow model to simulate a series of contingency analyses (simulation of opening each transmission element one at a time) and monitoring all transmission facilities above a select voltage level depending upon the study being performed. Normally, a constraint or limit to the transfer of power involves the loss of one transmission element (contingent element) and the resulting overload of another transmission element (monitored element). The limit can also be caused by voltage or stability violations, which are handled by establishing a rating on the facilities that would reflect the safe operating level below the voltage or stability limit. To the extent that a particular facility has exceeded 100% of its rating in previous studies or in real time operating conditions, Entergy considers the frequency and severity of those occurrences when determining whether the flowgate should be monitored.

Flowgates outside of the Entergy transmission system will also be included in the list of flowgates to be monitored as needed. These flowgates will generally be taken from the NERC Book of Flowgates and will be coordinated with the neighboring transmission provider as needed. These external flowgates are used to determine transfer capability values that may be limited by flowgates external to the Entergy transmission system.

2.2 Criteria for Adding/Removing Monitored Flowgates

For future additions and deletions of flowgates, Entergy will develop a stakeholder process in order to: (1) review the initial Master List of flowgates; (2) identify specific study criteria and processes to add and remove flowgates from the Master List of Flowgates; and (3) establish an annual stakeholder review process for future changes to the Master List of Flowgates. Within 30 days of the completion of the stakeholder process, Entergy will file a revised Attachment C, amending the list of criteria and processes for flowgate determination. Should the initial stakeholder process result in agreement between Entergy and the stakeholders, this revised list of criteria and processes for flowgate determination will be filed jointly. Should the initial stakeholder process fail to result in agreement between Entergy and the stakeholders, this revised list of criteria and processes for flowgate determination will be filed solely by Entergy without prejudice to the rights of the stakeholders to protest the filing or to submit alternative proposals.

The current Master List will be posted on the Entergy's OASIS.

3 Calculation of AFC Values

3.1 Base Case Models

As with other transfer capability methodologies, the AFC process will generate a “base case” model that simulates anticipated system conditions for the particular period in question. The base system conditions will include, among other things, projected load, generation dispatch, system configuration/outages, and base flow transactions. Under the AFC process, Entergy maintains power flow models representing three distinct time periods: (1) hourly models in the Operating and Planning Horizons for Hour 0 to Hour 168; (2) daily models in the Planning Horizon for Day 8 to Day 31; and (3) monthly models in the Study Horizon for Month 2 to Month 18. The power flow model used to determine constrained facility base flow and Response Factors for the Operating and Planning Horizons will be based on Entergy’s EMS and a state estimator snapshot of the real-time system. The power flow model for the Study Horizon will use an off-line power flow studies, such as PSS/E and MUST. The inputs used to generate base case models are described in Section 4. During the resynchronization process (described in Section 6), the base case models will be modified to reflect additional transactions as discrete injections and withdrawals. Using these models as the starting point, RFCalc will apply the formulas described below to compute the AFC value on each monitored flowgate.

3.2 AFC Formula for Firm Transmission Service Requests

OASIS Automation computes available flowgate capability using the following standard NERC formula for firm service:

$$\text{Firm AFC} = \text{Rating} - \text{TRM} - \text{CBM} - \text{Base Flow}_{\text{Firm}}$$

Where:

Firm AFC	=	the amount of firm transfer capability over that flowgate that remains available for additional transmission service reservations above and beyond existing uses of the transmission system
Rating	=	the capability of a flowgate in a time period
TRM	=	Transmission Reliability Margin
CBM	=	Capacity Benefit Margin
Base Flow (Firm)	=	the expected firm power flow through a flowgate in a time period with all pertinent flows included in the power flow base case

3.3 AFC Formula for Non-firm Transmission Service Requests

OASIS Automation computes available flowgate capability using the following standard NERC formula for non-firm service:

$$\text{Non-Firm AFC} = \text{Rating} - \text{TRM} - \text{Base Flow}_{\text{Non-Firm}}$$

Where:

Non-Firm AFC	=	the amount of non-firm transfer capability over that flowgate that remains available for additional transmission service reservations above and beyond existing uses of the transmission system
Rating	=	the capability of a flowgate in a time period
TRM	=	Transmission Reliability Margin
Base Flow (Non-Firm)	=	the expected firm and non-firm power flow through a Flowgate in a time period with all pertinent flows included in the power flow base case

3.4 AFC Calculation Horizons

AFC values are calculated for three different time periods: (1) the Operating Horizon, which includes all hours of the current day (Day 1) and, after 12:00 p.m., all hours of the next day (Day 2); (2) the Planning Horizon, which extends from the end of the Operating Horizon through the thirty-first day (Day 31); and (3) the Study Horizon, which extends from the end of the Planning Horizon through the eighteenth month (Month 18).

3.4.1 Operating Horizon

In the Operating Horizon (Day 1 to Day 2), the Non-Firm AFC values for each flowgate are calculated by OASIS Automation, which uses Response Factors and base flow calculated by RFCalc. The topology for the base case model for the first three hours in the Operating Horizon is generated by Entergy's State Estimator. The relevant unit commitment and load forecast inputs are incorporated into the model. Beyond the first three hours, Entergy creates the base case model using Entergy's Energy Management Systems (EMS) as modified to take into account outages, unit commitment, load forecasts and other system conditions. Using the power flow models and Non-Firm AFC formula discussed above, OASIS Automation calculates Non-Firm AFC values for all hours of Day 1 and, after 12:00 p.m., all hours of Day 2. This calculation is performed for Non-firm AFC values only. Firm AFC values are not calculated for the Operating Horizon because requests for firm transmission service must be submitted by 12:00 p.m. on the day prior to commencement of such service. Therefore, because firm service cannot be requested during the Operating Horizon, only Non-Firm AFCs are calculated for that horizon. All Non-Firm AFC values and Response Factors for the Operating Horizon are calculated and updated at least on an hourly basis to reflect changing system conditions, including additional confirmed transmission service reservations and schedules.

3.4.2 Planning Horizon

In the Planning Horizon (Day 2 to Day 31), Firm and Non-Firm AFC values for each flowgate are calculated by OASIS Automation, which uses Response Factors and base flow calculated by RFCalc. The base case model is generated using data from Entergy's EMS as modified to take into account outages, unit commitment, load forecasts and other system conditions. OASIS Automation calculates hourly Firm and Non-Firm AFC values for each flowgate for Day 2 through Day 7 and daily Firm and Non-Firm AFC values for Day 3 to Day 31. OASIS Automation updates both Firm AFC and Non-Firm AFC values for the Planning Horizon at least every day to reflect changing system conditions, including additional confirmed transmission service reservations. In between such updates, Non-Firm and Firm AFC values are decremented algebraically to reflect subsequent transmission service reservations.

3.4.3 Study Horizon

In the Study Horizon (Month 2 to Month 18), Entergy calculates monthly Response Factors and AFC values by conducting off-line power flow studies, such as PSS/E and MUST. The off-line planning models are developed on a rolling eighteen-month basis and are representative of monthly peak-hour conditions. Entergy calculates both Firm and Non-firm AFC values for the Study Horizon and updates those values at least on a monthly (currently weekly) basis to reflect changing system conditions and additional confirmed transmission reservations. In between such updates, Non-Firm and Firm AFC values are decremented algebraically to reflect subsequent transmission service reservations.

3.5 Resynchronization of AFC Values

AFC values will be recalculated or "resynchronized" every hour during the Operating Horizon, at least every day for the Planning Horizon, and no less than every month during the Study Horizon. Resynchronizations can occur more frequently if necessary, but will not occur less frequently. For the Operating and Planning Horizons, RFCalc incorporates all the data inputs during the resynchronization process to develop power flow models that define each time point included in the Operating and Study horizons. During the resynchronization process, prior commitment and accepted service requests are modeled into the base case as discrete injections and withdrawals, and new base flows are determined from these models. Using the new base flow amounts and models, RFCalc recalculates the base flow value on each monitored flowgate in the Master List. For the Study Horizon, this process is performed by an off-line AFC calculator. When a new request for transmission service is accepted in between resynchronizations, the most limiting flowgates that are significantly impacted by that particular request will be updated on OASIS by algebraically decrementing the appropriate AFC values. At the time of the next resynchronization, the service requests that have been approved since the last resynchronization will then be modeled as physical injections and withdrawals in the same manner of all other previously granted service requests

4 Inputs to Base Case Models and the AFC Formulas

4.1 Base Flow

The Base Flow calculation for Firm AFC values will take into account all existing firm uses of the transmission system, including capacity reserved for: (1) firm point-to-point transmission service; (2) service to network and native load customers; and (3) other firm transmission service, such as service under pre-Order No. 888 grandfathered agreements. The Base Flow calculation will also take into account any relevant counterflows as discussed below.

Entergy will model the output of QF/Cogeneration units to a level sufficient to meet at any host load requirements (currently QF/cogeneration units are purely reservation based and are set to zero initially). To the extent there is a firm or non-firm reservation from a QF, it will be handled the same as a firm or non-firm reservation from any other source on the Entergy system.

Requests to designate a new network resource by an existing network customer within the Entergy control area may also be submitted as a “displacement” of existing network resources. To generate the AFC values associated with a displacement request, the AFC process modifies the base flows to reflect a reduction in the output of the existing oil and gas-fired generating resources within the Entergy control area while still honoring the bulk transfer limits within the control area.

4.2 TRM

Transmission Reliability Margin is the amount of transmission transfer capability needed to provide a reasonable level of assurance that the system will remain reliable. TRM accounts for the inherent uncertainty in system conditions and its associated effects on AFC calculation, and the need for operating flexibility to ensure reliable system operation as system conditions change. The current value of TRM used by Entergy for the purposes of short-term AFC calculations for eighteen months or less is zero.

4.3 CBM

Capacity Benefit Margin is capacity that is reserved based on previous historical summer peak data. CBM is allocated in the form of firm reservations across 7 control area interfaces with Entergy. CBM is released day-ahead and sold on a non-firm basis. In the AFC process, during resynchronization, the CBM is modeled as a firm transaction into the model. The base flow value on each flowgate includes the effects of CBM reservations. For non-firm AFC calculations, the flowgate AFC is adjusted to remove the effects of CBM reservations to conform to the policy of releasing CBM as non-firm service on a day-ahead basis. The current CBM reservation amount used by Entergy for the purposes of short-term AFC calculations for eighteen months or less is zero for all control area interfaces.

4.4 Counter-Flows

4.4.1 Standard Counter-Flow Calculation

Entergy adjusts the base flow associated with a particular flowgate by removing a percentage of counterflow impacts in the calculation of AFC values. Entergy includes only a percentage of counterflows in order to account for the uncertainty that counterflow transactions will actually be scheduled. To arrive at the percentage of counterflow impacts for implementation of the AFC process, Entergy will examine historical data related to the scheduling of firm and non-firm transmission service. The counterflow percentage will be calculated separately for Firm and Non-Firm service and will be applied in the Operating and Planning Horizons for Non-Firm AFC and in the Planning and Study Horizons for Firm AFC.

The RFCALC application uses counter flow factors defined in the AFC manual to compute AFC values for the monitored flowgates. The formula used for adjusting base flows to take into account counterflows is described below:

$$Adjusted\ Base\ Flow\ _{Flowgate1} = Original\ Base\ Flow_{Flowgate1} + (CF_1 * X^{'})$$

Where,

X = Positive Flow

$X^{'}$ = CounterFlow

$$Original\ Base\ Flow_{Flowgate1} = X - X^{'}$$

CF_1 = Counter Flow factor

$$AFC\ _{Flowgate1} = TTC_{Flowgate1} - Adjusted\ Base\ Flow\ _{Flowgate1}$$

Based on currently available data, Entergy will include 70% of counterflows created by non-firm reservations when evaluating transmission service requests in the Operating, Planning and Study Horizons. Entergy will include 50% of counterflows created by firm reservations when evaluating transmission service requests in the Planning and Study Horizons. Because Non-Firm AFC in the Operating Horizon is based on service that is actually scheduled, Entergy will include 100% of counterflows created by firm schedules when evaluating transmission service requests in the Operating Horizon.

Entergy will reviews scheduling data and other operational experience on a bi-annual basis to determine the viability of the established counterflow percentages. To the extent the data and operational experience indicate that the percentage should be revised, Entergy will publicly-post notice of any such change prior to effectiveness.

4.4.2 Suspension of Standard Calculation for Operating and Planning Horizon

Entergy has temporarily disabled the counterflow (removal) feature in the Operating and Planning Horizons, which means that Entergy is currently including 100% of the counterflows in its AFC calculations. This feature was turned off to help moderate fluctuations in participation factor calculations for short-term AFC calculations. Entergy will continue to monitor the need to reinstate the counter flow adjustments in the operating and planning horizons, based on system conditions and after evaluating the performance of static participation factors. Counter flow adjustments continue to be applied in the Study horizon.

4.5 Transmission Facility Ratings

4.5.1 Introduction

A transmission facility consists of all elements carrying load between circuit breakers or the comparable switching devices. Transformers with both primary and secondary windings energized at 69 kV or above are subject to these criteria. All circuit ratings are computed with the system operated in its normal state (all lines and buses in-service, all breakers with normal status, all loads served from their normal source). The circuit ratings are specified in "MVA" and are taken as the minimum ratings of all of the elements in series. The minimum circuit rating is determined as described in these criteria and Entergy maintains transmission right-of-way to operate at this rating. However, Entergy may use circuit ratings higher than these minimums. Each element of a circuit has both a normal and an emergency rating and is defined as follows:

- ♦ NORMAL RATING: Normal circuit ratings specify the level of power flow that facilities can carry continuously without damage or loss of life to the facility involved.

- ♦ EMERGENCY RATING: Emergency circuit ratings specify the level of power flow that a facility can carry for the time sufficient for adjustment of transfer schedules, generation dispatch, or line switching in an orderly manner with acceptable loss of life to the facility involved.

In many instances these two ratings for Entergy facilities will be identical for power flow model purposes and the emergency rating is used for contingency evaluation.

4.5.2 Power Transformer

Power transformer loading guidelines are established in ANSI/IEEE C57.91-1995, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers rated 55°C or 65°C Winding.

Every transformer has a temperature rise capability based on its nameplate rating (either 55°C or 65°C). These temperature rise amounts reflect the average winding temperature rise over a 30°C ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.

The normal circuit rating for power transformers is its highest nameplate rating. The nameplate rating includes the effects of forced cooling equipment if it is available. For multi-rated transformers (ONAN/ONAF, ONAN/ONAN/ONAF, ONAN/OFAF/OFAF, ONAN/ONAF/OFAF, etc.) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available. Normal thermal life expectancy will occur with a transformer operated at continuous nameplate rating.

When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The emergency circuit rating for power transformers is normally a minimum of 100% of its highest nameplate rating.

4.5.3 Overhead Conductor

Entergy's transmission system consists of 15,000 miles of transmission lines. Existing lines have been built over a long span of years, under a variety of NESC codes, by decentralized engineering departments (until 1992) and under various engineering management.

Entergy conductor ratings are based on the "IEEE Standard for Calculation of Bare Overhead Conductor Temperature and Ampacity. Under Steady-State Conditions," ANSI/IEEE Standard 738-1993. (Prior to the promulgation of the ANSI/IEEE standard, conductor ratings were based on the "House and Tuttle" method, which formed the basis for the ANSI/IEEE standard.) The ANSI/IEEE standard uses as inputs to the calculation several company-chosen assumptions about ambient and operating conditions. For older vintage lines, Entergy adheres to the recorded ratings.

Entergy's system-wide standards for ambient and operating assumptions include the following:

- Line altitude — 0 feet mean sea level
- Line Latitude — 30 degrees North Latitude
- Line Orientation — East-West
- Coefficient of Emissivity — 0.5
- Coefficient of Absorption — 0.5
- Atmospheric quality — Clear
- Time of day — 12 noon
- Ambient temperature — 40degC (104degF)
- Ambient wind speed — 2 fps
- Wind-conductor angle — 90 degrees

The selection of a maximum conductor temperature affects both the operation and design of transmission lines. Existing transmission lines were designed to meet operating standards in effect at the time the line was built. Over time, these standards have been modified, as reflected in revisions to the National Electric Safety Code (NESC). For those existing lines that were designed to meet an earlier standard, Entergy will apply a rating that is consistent with the NESC design standards being practiced at the time the line was built. Entergy's current maximum conductor operating temperatures are as follows:

ACSR	100C
ACAR	80C
AAC	80C
Cu	95C
ACSS	180C

4.5.4 Other Transmission Equipment

In addition to the power transformers and overhead conductors, Entergy will also rate other transmission equipment, including underground cables, wave traps, switches, current transformers, and circuit breakers. Ratings for these types of transmission equipment will be determined in accordance with applicable ANSI/IEEE Standards.

4.5.5 Circuit Rating Issues

There may be instances when the flow on a transmission circuit is limited by factors other than the thermal capacity of its elements. The limit may be caused by other factors such as stability, phase angle difference, relay settings or voltage limitations.

When a tie line exists between two member systems, use of this criteria will result in a uniform circuit rating that is determined on a consistent basis between the two systems. Entergy follows this criteria to rate the circuit elements owned by them and will coordinate the rating of the tie line with the co-owner such that it utilizes the lowest rating between the two systems.

Entergy may have a contractual interest in a joint ownership transmission line whereby the capacity of the line is allocated among the owners. The allocated capacity may be based upon the thermal capacity of the line or other considerations. Entergy will follow this criteria to rate the circuit elements owned by them and will coordinate the rating of the tie line with the co-owner such that it utilizes the lowest rating between the two systems.

There may be instances when a derating of a transmission line element is required due to damaged equipment. The limit may be caused by such factors as broken strands, damaged connectors, failed cooling fans, or other damage reducing the thermal capability.

5 Response Factors

5.1 Introduction to Response Factors

Response Factors measure the impact (*i.e.,* the incremental loading) that each source-to-sink transaction has on a monitored flowgate. Response Factors are calculated on a transaction-specific and flowgate-specific basis. Response Factors are transaction-specific in the sense that each source-to-sink pair will have a set of Response Factors based on the power flows associated with that source-to-sink pair. Response Factors are flowgate-specific in the sense that every source-to-sink transaction will have a distinct Response Factor for each monitored flowgate. Thus, each individual Response Factor represents the percentage of power flow from a specific source-to-sink transaction that impacts a specific flowgate. To implement transaction-specific Response Factors, Entergy calculates Response Factors for each generator that is directly interconnected with the Entergy transmission system, including all generators within the Entergy control area, regardless of ownership or affiliation. Response Factors are also calculated, on an as needed basis, for other generators that are located in such close electric proximity to the Entergy transmission system that they have a specific impact on that system (*e.g.*, "border" generating units that are located in a non-Entergy control area but are interconnected in close proximity to the Entergy transmission system). Response Factors are also calculated, on an as needed basis, for control areas that are directly interconnected to the transmission system and are applied to transmission service requests from generators that do not have specific Response Factors. To calculate Response Factors, Entergy uses the RFCalc software utilizing state estimator models in the Operations and Planning Horizons, and off-line planning models, such as PSS/E and MUST, to calculate Response Factors in the Study Horizon.

5.2 Updating Response Factors

Response Factors are resynchronized on the same basis as AFC values, *i.e.,* every hour during the Operating Horizon, at least every day (four times a day) for the Planning Horizon, and no less than every month (currently weekly) during the Study Horizon. Resynchronizations can occur more frequently if necessary, but do not occur less frequently.

5.3 Response Factors for Generators Outside of the Entergy Control Area

For generators outside of the Entergy control area, Entergy will calculate Response Factors for non-Entergy control areas. These Response Factors will be used to evaluate service requests from each generator in the non-Entergy control area, unless a generator-specific Response Factor has been calculated for a "border" generating unit.

For transactions that source in a non-Entergy control area, Entergy will calculate Response Factors for the non-Entergy control area by ramping up available generating facilities in the non-Entergy control area on a modified *pro rata* basis, such that all generating facilities reach their rated maximum outputs (P_{max}) simultaneously. For transactions that sink in a non-Entergy control area, Entergy will calculate Response Factors for the non-Entergy control area by ramping down available generating facilities in the non-Entergy control area on a modified *pro rata* basis, such that all generating facilities reach their rated minimum outputs (P_{min}) simultaneously.

Entergy will calculate generator-specific Response Factors, on an as needed basis, for "border" generating units, *i.e.*, generating facilities that are located on other transmission systems/control areas and are also in "close electric proximity" to the Entergy transmission system.   Because border generating facilities are either directly interconnected with the Entergy transmission system, or are interconnected within one or two busses of the Entergy transmission system, the impact of transfers from those facilities is typically different from the impact of other generating facilities in the non-Entergy control area, particularly if the non-Entergy control area has a significant number of generating facilities. To determine whether generator-specific Response Factors should be calculated for border generating facilities, Entergy will apply two criteria. First, the generator will have to be in close electric proximity to the Entergy transmission system such that the generator is either: (1) directly interconnected with the Entergy transmission system, but located in a different control area; or (2) interconnected with the transmission system of another transmission provider within one or two busses of the Entergy transmission system. Second, there will have to be a significant discrepancy between the Response Factors for all other generators in the non-Entergy control area and the Response Factors for the specific border generating facility in question.

5.4 Response Factor Cutoff

In order to evaluate whether a particular service request will use all, some, or none of the AFC for a particular flowgate, Entergy uses RFCalc, State Estimator models and off-line planning models to calculate Response Factors. Like Outage Transfer Distribution Factors, the Response Factors generated by Entergy's AFC process measures the power flow impact that each source-to-sink transaction has on each flowgate for the post-contingency configuration of the system. If the power flow impact of particular transmission service request has an insignificant impact on a flowgate, that flowgate is not monitored when evaluating the request. To determine whether a flowgate is significantly impacted by a particular service request, Entergy applies a Response Factor threshold of 3%. Only Response Factors at or above the 3% threshold will be considered when determining whether to approve the transmission service request. Thus, if the Response Factor for a particular flowgate is less than 3%, then the AFC process will not consider the flowgate when determining whether service should be granted. If the Response Factor for a particular flowgate is equal to or greater than 3%, and the AFC value indicates that the flowgate is one of the most limiting flowgates for that transaction, then the flowgate will be evaluated to determine whether the particular service request should be granted.

5.5 Modified Response Factor Cutoff

If operating conditions indicate that a revision to the Response Factor threshold is necessary to enable accurate representation of system transfer capability and thereby maintain system reliability, then Entergy will reevaluate this threshold. All changes to the Response Factor threshold will be filed with FERC.

6 OASIS Automation and Evaluating Service Requests

OASIS Automation is the tool that will automatically process requests for transmission service under the AFC process. OASIS Automation serves as the link between the AFC calculation process and the reserving and scheduling of transmission service under the Entergy OATT. As individual transmission service requests are received, OASIS Automation applies the applicable Response Factors to determine the impact new requests will have on the relevant flowgates and approves or denies the request based on that impact.

6.1 Flowgates Used to Evaluate Requests

Although the AFC process will monitor approximately 300-500 flowgates, OASIS Automation will use a more limited set of flowgates, as determined by RFCalc, to evaluate individual service requests. When evaluating individual service requests, Entergy will only consider those flowgates that are: (1) "significantly impacted" by the request at issue, i.e., those flowgates with a Response Factor equal to or greater than 3%; and (2) the "most limiting flowgates" for the request at issue, i.e. the fifteen flowgates with the lowest effective ATC values. Thus, to determine which flowgates should be evaluated for a particular source-sink combination, RFCalc will: (1) ignore all flowgates with a Response Factor of less than the Response Factor cutoff of 3%; and (2) will select from the remaining flowgates the fifteen flowgates with the lowest effective ATC values. The list of flowgates used to evaluate a particular service request will be redetermined during each resynchronization.

The reason for limiting the number of flowgates used to evaluate individual service requests is driven by performance requirements. A large number of flowgates results in additional data transfers and lengthened computation time, both of which lead to slower response times by the automation process. This adverse impact on response times is particularly increased in the Operating and Planning Horizons where the frequency of resynchronizations is high and is reduced in the Study Horizon where the frequency of resynchronization is once a month. Nevertheless, to implement the AFC process, Entergy will determine the list of flowgates used to evaluate service requests in all horizons under the methodology described above.

6.2 Approving and Denying Service

As individual transmission requests are submitted over OASIS, OASIS Automation will apply the appropriate Response Factors to each request in order to evaluate the impact of the request on the most-limiting, significantly-affected flowgates. The amount of capacity requested will be multiplied by the Response Factor for a particular flowgate. The product of the requested capacity and the Response Factor will represent the additional loading impact of the new service on the flowgate and will be subtracted from the AFC value for that flowgate. As discussed above, this process will be applied to the top 15 limiting flowgates. If the AFC for all the flowgates remains positive or equal to zero after being reduced to account for the new transaction, the request will be approved. If the AFC value on any of the flowgates becomes negative or otherwise exceeds the rated capability of the facilities in question, then the request will be denied, unless transmission service of a lower priority may be preempted to bring the AFC value back to zero or positive. The preempting of service with a lower priority will be conducted pursuant to the preemption principles in FERC's Order No. 638 or its successor.

6.3 Pmax and Interface Limits

Regardless of the applicable AFC values, accepted transmission service requests from a particular generator shall not exceed the maximum output of that generator. Additionally, the amount of transmission service available across a control area interface can not exceed the total interface rating between the two control areas. Consistent with NERC Operating Policies and operating agreements, the capacity between these interfaces is rated. This limit is typically defined by the thermal limit of all transmission facilities that define the interface. Other control area interfaces may be limited based upon the maximum generation capability or load of that neighboring control area. Both the Pmax and Interface limits will be honored in the AFC process through a proxy flowgate. To the extent that the service request exceeds either the Pmax or interface limit, the proxy flowgate will appear as one of the most limiting flowgates for that particular transaction.

6.4 Redirect Requests and Displacement

Requests to redirect all or a portion of a firm transmission reservation from an alternate point-of-receipt (source) or to an alternative point-of-delivery (sink) on a firm basis is evaluated in the following manner. First, the fifteen flowgates most limited by each request (the original request and the redirect request) are identified. Next, the AFC values are used to separate the flowgates into two groups. Group 1 includes flowgates that have an AFC value that is less than or equal to zero *and* are common to both requests. Group 2 includes the remaining flowgates identified in the list of the fifteen flowgates most limited by the redirect request. Next, the current impact of the original request is removed from the AFC value of the flowgates in both groups (the AFC value is increased by the capacity of the request multiplied by the response factor of each flowgate). Note that the current impact of the original request may differ from the impact originally evaluated because power flows may have changed since the original request was accepted. The impact of the redirect request is then calculated and evaluated as follows:

- If the impact of the redirect request causes the AFC of any flowgate in Group 1 to decrease, the redirect request will be denied.
- If the AFC value of any flowgate in group 2 is less than or equal to zero, before applying the impact of the redirect request, the redirect will be denied.
- If the impact of the redirect request causes the AFC of any flowgate in Group 2 to drop below zero, a counteroffer may be made for a MW amount equal to the MWs that would cause the AFC of the most limited flowgate (i.e. the flowgate with the largest negative AFC value) in Group 2 to equal zero.
- In all other circumstances, the redirect request will be accepted.

Network customers can use the Redirect capabilities of OASIS as a displacement option to substitute a source of an existing network resource reservation with a new network resource.

7 Scenario Analyzer

7.1 Introduction

Entergy provides a tool that allows transmission customers to instantaneously evaluate transfer capability without actually submitting an OASIS request. This tool – known as the Scenario Analyzer – is a part of the OASIS and allows customers to enter potential transmission service requests for analysis of transfer capability without submitting actual requests over Entergy's OASIS. The Scenario Analyzer provides customers with an immediate response by performing the same flow-based review that is used by OASIS Automation to determine whether actual service requests can be accommodated. If sufficient AFC exists, the Scenario Analyzer notifies the customer if sufficient ATC is available for the proposed request. If sufficient AFC does not exist, the Scenario Analyzer provides the transmission customer the following information: all constrained flowgates, the hour(s) when the constraints exists, the amount of flowgate capacity available, and the transfer capability that is available. However, because the Scenario Analyzer does not submit an actual service request over OASIS, it does not decrement flowgate AFC. The Scenario Analyzer uses the same flow-based engine as OASIS Automation.

There are two evaluation options under the Scenario Analyzer. The original Scenario Analyzer ("Analyze Operating AFC" on OASIS) provides customers with AFC information that reflects all queued requests with a status of Confirmed, Accepted, Counteroffer, and Study taken into account. The second Scenario Analyzer option ("Analyze Confirmed AFC" on OASIS) provides customers with AFC results (i.e. decrements to the AFC) based only on confirmed reservations.

7.2 How to use the Scenario Analyzer

The Scenario Analyzer is an OASIS module that allows Transmission Customers to evaluate availability on certain designated constrained facilities for the Source and Sink pair, but does not decrement ATC since no request has been submitted. Information is entered on a form for:

Source name
Sink name
POR name
POD name
Capacity type
Begin time (for each time segment)
End time (for each time segment)
Capacity value (for each time segment)

After entering information in the submit request form on OASIS, ‘ANALYZE OPERATING AFC’ or ‘ANALYZE CONFIRMED AFC’ is selected to view ATC without actually submitting a request for service. A request for service would be issued to OASIS if the SUBMIT option were chosen after completing the form. The resulting display will provide the user with a profiled path ATC for the duration of the request, and provide all limiting constraints for the different time periods. The customer can then select the SUBMIT button, provided on the Scenario Analyzer Results page, to submit the request as a valid request, regardless of the results of the analysis request.

User certification is required for access to the Scenario Analyzer.

8 System Impact Studies

A System Impact Study (SIS) is an in-depth analysis of whether a request for transmission service can be reliably accommodated. System Impact Studies are conducted to assess the impact of a request for service when the request cannot be accommodated based on the initial analysis of AFC.

If the AFC process indicates that transmission service is not available, Entergy will conduct – at the request of the transmission customer – a transaction-specific System Impact Study that will examine the potential for transmission system upgrades to increase the applicable AFC values. Because the AFC process already provides source-to-sink analysis based on the most up to date information available, these System Impact Studies will be focused on system upgrades, taking into account the lead time required to construct new transmission system upgrades. Long-term transmission service requests and short-term transmission service requests for time periods beyond the Study Horizon will continue to be evaluated under the System Impact Study process.

Entergy will also evaluate requests for displacement of network resources using the SIS process. The request for displacement can be submitted over the OASIS by submitting indicating the resource(s) that will be used to displace the study network resource. If the study shows that the displacement can be accommodated reliably, the appropriate amount of network service will be recalled from the displaced resource.

Further information regarding System Impact Studies can be found in Entergy's System Impact Studies Procedures posted on Entergy's website at: "http://www.entergy.com/transmission/".

9 Informational Postings and Data Archive

9.1 Models posted on OASIS

Entergy will post the following information related to the power flow models used to calculate AFC.

1. A daily peak model for each day of the Day 1- 31 time frame

2. A monthly peak model for each month of the Month 2 -18 time frame

3. Four hourly models for each day for the Day 1-7 time frame

The daily models will be refreshed at least daily to maintain a rolling 31-day posting. Similarly, the monthly models will be refreshed at least monthly to maintain a rolling 18 month posting. The hourly models are randomly selected and represent an hour within a six-hour window of each day. Model 1 represents any hour between hour 0000 and hour 0600, model 2 represents any hour between hour 0700 and 1200, model 3 represents any hour between hour 1300 and 1800, and model 4 represents any hour between 1900 and 2300. Only the six-hour window of the model is disclosed, not the exact hour of the model. All power flow models will be posted in the Power Technologies Inc (PTI) Version 26 RAWD format.

9.2 Input files

From the monthly models, Entergy will also provide a subsystem file that defines all sources and sinks used for calculating AFC values. User certification is required for access to this data.

Entergy also posts the following informational files related to AFC:

- A file containing response factors of top 15 flowgates per path and base flow for each flowgate for each time point. The file is refreshed hourly.

- A file containing the Effective ATC value of each path for each time point.

- A file containing the list of generators used as the Entergy control area sink for response factor calculation. The file also lists the participation factors for these generators.

- A subsystem files defining all sources and sinks used to calculate AFC.

- A list of flowgates with TTC and a revision log for all flowgate changes.

9.3 Transmission outage plans

Entergy will post on its OASIS a list of all scheduled outages on transmission facilities on the Entergy transmission system. The posting will include a daily posting for the Day 1 – 31 timeframe and a monthly posting for the Month 2 – 13 time frame.

9.4 Data Archive

Entergy retains data, models and information about the methodology used for calculations for a period of time in compliance with FERC regulations. All data files necessary to re-evaluate system planning studies or network impact studies will be archived based on a two year retention time. This data will be date stamped and stored in a retrievable format. This data can be made available upon reasonable request.

10 Regional coordination of transfer capability determinations

Entergy will continue to coordinate transfer capability values with neighboring utilities in accordance with NERC and Regional Reliability Council criteria. Seasonal reliability models will continue to be developed on a Regional Reliability Council basis. Source assumptions will be made in order to coordinate transfer capability values with the neighboring transmission providers.

Where necessary, Entergy will coordinate reservation and schedule information with neighboring control areas so that transfer capability can be properly coordinated. Entergy will also honor flowgate limits on neighboring transmission systems when constraints are experienced.

11 APPENDIX A: Historical Reservation Data used for Determination of Counterflows

	Percentage of Reservations Scheduled in Real Time					
	Firm PTP	Firm Network	Firm total	Non-Firm PTP	Non-Firm Network	Non-Firm total
January-2003	35	24	28	102	67	78
February-2003	31	22	26	108	69	78
March-2003	30	21	24	92	61	71
April-2003	27	24	26	99	51	58
May-2003	28	27	27	86	54	60
June-2003	29	23	24	113	55	62
July-2003	33	29	30	87	54	60
August-2003	39	29	31	80	54	60
September-2003	39	25	27	98	70	75
October-2003	43	22	25	96	72	75
November-2003	43	20	24	100	83	86
December-2003	46	21	25	101	69	75
TOTAL	35	24	27	95	62	69

12 APPENDIX B: Master Flowgate List Citing Source and Criteria

Mapname	Description	LE Bus	CE Bus	FG Rating (MVA)	FGID
ACHMON_WGWAT	ALCHEM-MONCHEM 138 FTLO WILLOW GLEN-WATERFORD 500	98255,98271	98246,98539	225	FG_001
ACSCN_RICSCT	ACADIA-SCANLAN 138 FTLO RICHARD-SCOTT 138	98111,98112	98108,98130	209	FG_002
ADDTIG_CHTAI	ADDIS-TIGER 230 FTLO CHOCTAW-AIR LIQUIDE TAP 230	98250,98362	98263,98474	422	FG_003
ADDTIG_WEBCA	ADDIS-TIGER 230 FTLO CAJUN-WEBRE 500	98250,98362	97301,98430	422	FG_004
ALLHOR_FRPXF	ALLEN-HORN LAKE 161 FTLO FREEPORT 500/230	18022,98702	18009,98707	226	FG_005
AMLHLB_HBCYP	AMELIA-HELBIG 230 FTLO HARTBURG-CYPRESS 500	97696,97689	97717,97691	685	FG_006
ANDIN_MCLK_D	INDIANOLA-ANDRUS 230 FTLO MCADAMS-LAKEOVER 500	98769,98759	98808,98935	462	FG_007
ANDIND_ANDBG	ANDRUS-INDIANOLA 230 FTLO ANDRUS-BAGBY 230	98759,98769	98759,99306	462	FG_008
ANDIND_ANDCL	ANDRUS-INDOLA 230 FTLO ANDRUS-CLNTON INDUSTRIAL 230	98759,98769	98759,98893	462	FG_009
ANDIND_MCLAK	ANDRUS-INDOLA 230 FTLO LAKEOVER-MCADAMS 500	98759,98769	98935,98808	462	FG_010
ANGRNV_ANDIN	ANDRUS-GREENVILLE 115 FTLO ANDRUS-INDIANOLA 230	98760,98750	98759,98769	319	FG_011
ANUFTS_PLSHL	ANO-FT SMITH 500 FTLO ANO-PLEASANT HILL 500	99486,55305	99486,99197	1299	FG_012
ARKFTSM_ARK5	ANO-FT SMITH 500 FTLO ANO 500/161	99486,55305	99486,99487	1299	FG_013
ARKHTSP_ARKC	ARKLAHOMA-HOTSPRINGS 115 FTLO ARKLAHOMA-CARPENTER	99351,99403	99351,99355	266	FG_014
ARKHTSP_HSP5	ARKLAHOMA-HOT SPRINGS 115 FTLO HOT SPRINGS 500/115	99351,99403	99402,99403	266	FG_015
ARKPLHL_ARKM	ANO-PLEASANT HILL 500 FTLO ANO-MABLEVALE 500	99486,99197	99486,99565	1732	FG_016
ARXF_ARMABL	ANO 500/161 FTLO ANO-MABLEVALE 500	99486,99487	99486,99565	672	FG_017
ASHCH_COTHOU	ASHLAND-CHAUVIN 115 FTLO HOUMA-COTEAU 115	98525,97308	98523,98524	120	FG_018
B_WLTAL_PERY	BAXTER WILSON-TALLULA FTLO BAXTER WILSON-PERRYVILLE	98938,99154	98937,99203	199	FG_019
BAGSUN_WGWAT	BAGATELLE-SUNSHINE 230 FTLO WILLOW GLEN-WATERFORD 500	98569,98570	98246,98539	460	FG_020
BATBAT_MCWP	BATESVILLE-BATESVILLE TVA115 FTLO MCADAMS-WESTPOINT	98730,18041	98808,98700	398	FG_021
BATBS_LSPXFR	BATESVILLE-BATESVILLE 115 FTLO LS POWER 230/161	18041,98730	99900,98729	398	FG_022
BATCOM_BATMO	BATESVILLE-COMO 115 FTLO BATESVILLE-MOONLAKE 230	98730,98732	98729,99680	108	FG_023
BATCUS_INDEL	BATESVILLE-CUSHMAN 161 FTLO ISES-DELL 500	99798,99808	99818,99742	310	FG_024
BATSMRK_ENID	BATESVILLE-MARKS 115 FTLO BATESVILLE-ENID 230	98730,98731	98729,98735	108	FG_025
BAYGEN_MICSM	GENTILLY RD-BAYOU SAUVAGE 115 FTLO MICHOUD SOUTH-MICHOUD	98670,98669	98654,98656	175	FG_026
BEVJAN_MOHAR	BEAVER CREEK-JENA 115 FTLO HARTBURG-MT. OLIVE 500	99106,99108	97717,99162	80	FG_027
BEVXF_WIN230	BEAVER CREEK 138/115 FTLO WINNFIELD 230/115	50012,99106	99113,99112	93	FG_028

BLDFRK_RUSTF	BLAND-FRANKS 345 FTLO RUSH-ST. FRANCIS 345	30154,96041	31669,31773	949	FG_029
BONXFM_SCBON	BONIN 230/138 FTLO BONIN-SCOTT 138	50303,50304	98130,50304	300	FG_030
BRKBET_VLPIT	BRKN BW4-BETHEL 138 FTLO VALNT-PITTS 345	52814,54054	54037,54033	96	FG_031
BSMID_ANOPHL	BULL SHOALS-MIDWAY 161 FTLO ANO-PLEASANT HILL 500	52660,99825	99486,99197	162	FG_032
BVRJ_MCKFR_D	BEAVER CREEK-JENA 115 FTLO FRANKLIN-MCKNIGHT 500	99106,99108	99027,98235	80	FG_033
BVRJE_MCKFRK	JENA-BEAVER CREEK 115 FTLO MCKNIGHT-FRANKLIN 500	99106,99108	98235,99027	80	FG_034
BVRJE_WEBWLS	JENA-BEAVER CREEK 115 FTLO WEBRE-WELLS 500	99108,99106	98430,98109	80	FG_035
BVRXF_MKFR_D	BEAVER CREEK 138/115 FTLO FRANKLIN-MCKNIGHT 500	50012,99106	99027,98235	93	FG_036
BVRXFR_MKFRK	BEAVER CREEK 138/115 XFMR FTLO MCKNIGHT-FRANKLIN 500	50012,99106	98235,99027	93	FG_037
BWLSN_TAL3_D	TALULA-BAXTER WILSON 115 FTLO PERRYVILLE-BAXTER WILSON 500	99154,98938	99203,98937	199	FG_038
BWLVKS_VKSW	BAXTER WILSON-SOUTHEAST VICKSBURG FTLO VICKSBURG-VICKSBURG WEST	98938,98866	98941,98942	161	FG_039
BWTAL_STRPVL	BAXTER WILSON-TALULA 115 FTLO PERRYVILLE-STERLINGTON 500	98938,99154	99148,99203	199	FG_040
BWTL_STRPV_D	BAXTER WILSON-TALULA 115 FTLO PERRYVILLE-STERLINGTON 500	98938,99154	99203,99148	199	FG_041
BYRTRY_FRKRB	BYRAM-TERRY 115 FTLO RAY BRASWELL-FRANKLIN	98927,98928	98930,99027	161	FG_042
CHKDYB_SABCH	CHEEK-DAYTON 138 FTLO SABINE-CHINA 230	97692,97632	97716,97714	170	FG_043
CHKDYT_CHIJA	CHEEK-DAYTON 138 FTLO CHINA-JACINTO 230	97692,97632	97714,97721	170	FG_044
CLDXF_CLKMON	CLARKSDALE 230/115 FTLO CLARKSDALE-MOONLAKE 230	98854,98723	99680,98854	250	FG_045
CLDXF_TUNRIC	CLARKSDALE 230/115 FTLO RITCHIE-TUNICA 230	98854,98723	99651,98718	250	FG_046
CLIJXN_RBELK	CLINTON-NORTHWEST JACKSON 115 FTLO RAY BRASWELL-LAKEOVER 500	98911,98909	98930,98935	240	FG_047
CLYML_FCYM_D	MOLER-COLY 230 FTLO MCKNIGHT-FANCY 500	98420,98391	98235,98233	462	FG_048
CLYMOL_FCYMC	MOLER-COLY FTLO FANCY-MCKNIGHT 500	98420,98391	98233,98235	462	FG_049
CLYVIG_CNBAG	COLY-VIGNES FTLO CONWAY-BAGTEL 230	98391,97331	98259,98569	462	FG_050
CLYWIG_WGWAT	COLY-VIGNES 230 FTLO WILLOW GLEN-WATERFORD 500	98391,97331	98246,98539	462	FG_051
COLVIG_MKFRN	COLY-VIGNES 230 FTLO MCKNIGHT-FRANKLIN 500	98391,97331	98235,99027	462	FG_052
AACLIC_CLYVI	A.A.C-LICAR 230 FTLO COLY-VIGNES 230	98249,98270	98391,97331	685	FG_053
AACLIC_MCFRK	A.A.C.-LICAR 230 FTLO MCKNIGHT-FRNKLN 500	98249,98270	98235,99027	685	FG_054
CONBAG_WGPOL	BAGTELLE-CONWAY 230 FTLO WILLOW GLEN-POLSCAR 230	98569,98259	98247,98434	436	FG_055
AACLIC_WATXF	A.A.C.-LICAR 230 FTLO WILLOW GLEN WATERFORD	98249,98270	98246,98539	685	FG_056
CONCO_PLHGRN	CONWAY WEST-CONWAY SOUTH 161 FTLO PLEASANT HILL-GRENBRIER 161	99510,99485	99196,99517	223	FG_057
COTHOU_CHAVE	COTEAU-HOUMA 115 FTLO VALENTINE-CHAUVIN 115	98523,98524	98526,98525	227	FG_058
COULEW_ARKFT	COUCH-LEWIS 115 FTLO ANO-FT. SMITH 500	99230,99263	99486,55305	160	FG_059
COULEW_DOLSH	COUCH-LEWIS 115 FTLO DOLET HILLS-SOUTHWEST SHREVEPORT	99230,99263	50045,53454	160	FG_060

COULEW_ELDLW	COUCH-LEWIS115 FTLO ELDORADO-LONGWOOD 345	99230,99263	99294,53424	160	FG_061
COULEW_ELDXF	COUCH-LEWIS 115 FTLO ELDORADO 500/345	99230,99263	99295,99294	160	FG_062
COWCO_COWSA	COW-COLONIAL ORANGE 138 FTLO COW-SABINE 138	97617,97589	97617,97705	288	FG_063
CTHOU_VLNWAT	COTEAU-HOUMA 115 FTLO WATERFORD-VALENTINE 230	98523,98524	98537,98527	227	FG_064
CY138_CY500	CYPRESS 500/138 FTLO CYPRESS 500/230	97691,97690	97691,97713	750	FG_065
CY500_CY138	CYPRESS 500/230 FTLO CYPRESS 500/138	97691,97713	97691,97690	750	FG_066
DANMAG_FTARK	DANVILLE-MAGAZINE 161 FTLO ANO-FT. SMITH	99496,53201	99486,55305	148	FG_067
DANMCK500	DANIEL-MCKNIGHT 500 KV PTDF	15021,98235		1732	FG_068
DANOLA_FSANO	OLLA-DANVILLE 115 FTLO ANO-FT. SMITH 500	99498,99497	99486,55305	106	FG_069
DANOLA_SHMAG	DANVILLE-OLLA 115 FTLO SHERIDAN-MAGNET COVE 500	99497,99498	99333,99450	106	FG_070
DARDAM_FTARK	DARDANELLE-DARNDANVILLE DAM 161 FTLO ANO-FT.SMITH	52708,99494	99486,55305	232	FG_071
DAYCHE_JACXF	CHEEK-DAYTON 138 FTLO JACINTO 230/138	97692,97632	97478,97476	170	FG_072
DAYNLJ_JACCH	DAYTON-NEW LONG JOHN 138 FTLO CHINA-JACINTO 230	97633,97472	97714,97721	99	FG_073
DAYNLJ_JACXF	DAYTON-NEW LONG JOHN 138 FTLO JACINTO 230/138	97633,97472	97478,97476	99	FG_074
DELRUL_CLDEL	DELTA-RULEVILLE 115 FTLO DELTA-CLEVELAND	98737,98794	98737,98726	85	FG_075
DELSH_BXWP_D	SHELBY-DELTA 115 FTLO PERRYVILLE-BAXTER WILSON 500	98724,98737	99203,98937	87	FG_076
DELSHE_BAMNL	DELTA-SHELBY SWITCHING STATION 115 FTLO BATESVILLE-MOONLAKE 230	98737,98724	98729,99680	87	FG_077
DELSHE_BAXWP	DELTA-SHELBY SWITCHING STATION 115 FTLO BAXTER WILSON-PERRYVILLE	98737,98724	98937,99203	87	FG_078
DELSHE_STPEV	DELTA-SHELBY SWITCHING STATION 115 FTLO PERRYVILLE-STERLINGTON	98737,98724	99203,99148	87	FG_079
DELSHE_WMBST	DELL-SHELBY 500 FTLO WEST MEMPHIS-BIRMINGHAM STEEL	99742,18008	99788,18051	2165	FG_080
DELTAL_BAXPV	TALULAH-DELHI 115 FTLO BAXTER WILSON-PERRYVILLE	99154,99155	98937,99203	80	FG_081
DLSH_STPEV_D	SHELBY-DELTA 115 FTLO STERLINGTON-PERRYVILLE 500	98724,98737	99148,99203	87	FG_082
DODDAN_HARMT	DODSON-DANVILLE 115 FTLO MT. OLIVE-HARTBURG 500	99182,99174	99162,97717	176	FG_083
DODDN_HRMT_D	DODSON-DANVILLE 115 FTLO HARTBURG-MT. OLIVE 500	99174,99182	99162,97717	176	FG_084
DODWI_ELDMTO	WINNFIELD-DODSON 115 FTLO ELDORADO-MT. OLIVE 500	99112,99174	99295,99162	176	FG_085
DOLXFM_ELDXF	DOLET 345/230 FTLO ELDORADO EHV 500/345	50045,50046	99295,99294	700	FG_086
DUBBU_WEBWLS	DUBOIN-BULL WAREHOUSE 138 FTLO WEBRE-WELLS 500	98185,98184	98430,98109	112	FG_087
ELDAT1_MCNAT	ELDORADO 500/115 FTLO MCNEIL 500/115	99295,99293	99309,99310	448	FG_088
ELDXF_VALLYD	ELDORADO 345/500 FTLO LYDIA-VALIANT 345	99294,99295	53277,54037	717	FG_089
ELEHVMOLIVE	ELDORADO-MT. OLIVE 500 KV PTDF	99295,99162		1732	FG_090
ESODMT_EXDNT	ESSO-DELMONT 230 FTLO EXXON-DOWNTOWN 230	98309,98406	98310,98400	339	FG_091
ESODMT_WGCLY	ESSO-DELMONT 230 FTLO COLY-WILLOW GLEN	98309,98406	98390,98246	339	FG_092

ESSDEL_ADTIG	ESSO-DELMONT 230 FTLO ADDIS-TIGER 230	98309,98406	98250,98362	339	FG_093
ESSDEL_WEBCJ	ESSO-DELMONT 230 FTLO CAJUN-WEBRE 500	98309,98406	97301,98430	339	FG_094
ESSDEL_WGPEC	ESSO-DELMONT 230 FTLO WILLOW GLEN-PECUE 230	98309,98406	98247,98404	339	FG_095
FANCAJ_WEBCA	CAJUN-FANCY 500 FTLO CAJUN-WEBRE 500	97301,98233	97301,98430	2048	FG_096
FLRJAX_SLHEB	JACKSON SOUTH-FLORENCE FTLO SILVER CREEK-NORTH HEBRON	98899,98955	99049,99050	160	FG_097
FRARAY_FRBOG	FRANKLIN-RAY BRASWELL 500 FTLO FRANKLIN-BOGALUSA	99027,98930	99027,98487	1732	FG_098
FRAVA_FRNBRO	FRANKLIN-VAUGHN 115 FTLO FRANKLIN-BROOKHAVEN SOUTH 115	99028,99064	99028,99039	161	FG_099
FRKLMCKN_D	FRANKLIN-MCKNIGHT 500 PTDF	99027,98235		2070	FG_100
FRKLMCKNIT	FRANKLIN-MCKNIGHT 500 KV PTDF	99027,98235		2070	FG_101
FRPROB_FRPXF	ROBINSONVILLE-FREEPORT 230 FTLO FREEPORT 500/230	98710,98707	18009,98707	462	FG_102
FRRAY_FRBG_D	FRANKLIN-RAY BRASWELL 500 FTLO FRANKLIN-BOGALUSA 500	99027,98930	99027,98487	1732	FG_103
FS500_FS500	FT. SMITH 500/161 FTLO FT. SMITH 500/345	55305,55300	55305,55302	440	FG_104
GEOHEL_SACHI	GEORGETOWN-HELBIG 230 FTLO SABINE-CHINA 230	97744,97696	97716,97714	402	FG_105
GGFRN_BAWGR	GRAND GULF-FRANKLIN 500 FTLO GRAND GULF-BAXTER WILSON	98952,99027	98952,98937	1732	FG_106
GONSOR_CONBG	GONZALES-SORRENTO 138 FTLO CONWAY-BAGTELLE 230	98268,98545	98259,98569	130	FG_107
GONSOR_VICOL	GONZALES-SORRENTO 138 FTLO COLY-VIGNES	98268,98545	98391,97331	130	FG_108
GRIMTZ_WDN	GRIMES-MT. ZION 138 FTLO GRIMES-WALDEN 138	97514,97487	97514,97454	206	FG_109
GRIWAL_GRICR	WALDEN-GRIMES 138 FTLO CROCKETT-GRIMES	97454,97514	53526,97513	206	FG_110
GRNLE_ANDIND	GREENVILLE-LELAND 115 FTLO ANDRUS-INDIANOLA 230	98750,98748	98759,98769	161	FG_111
GYPFAV_FRSOR	LITTLE GYPSY-FAIRVIEW230 FTLO SORRENTO-FRENCH SETTLEMENT	98555,98498	98544,97314	454	FG_112
GYPFAV_FSMIC	LITTLE GYPSY-FAIRVIEW 230 FTLO MICHOUD-FRONT STREET 230	98555,98498	98652,50070	454	FG_113
HAMIN_MCKFRN	HAMMOND-INDEPENDENCE 115 FTLO MCKNIGHT-FRANKLIN 500	98484,98482	98235,99027	168	FG_114
HAMN_MCKFR_D	HAMMOND-INDEPENDENCE 115 FTLO FRANKLIN-MCKNIGHT 500	98484,98482	99027,98235	168	FG_115
HAMXF_MCKFRK	HAMMOND 230/115 FTLO MCKNIGHT-FRANKLIN 500	98483,98484	98235,99027	168	FG_116
HAYBLY_NMDEL	HAYTI-BLYTHEVILLE INTERSTATE 161 FTLO NEW MADRID-DELL 500	99748,99735	96035,99742	335	FG_117
HELGTW_HBNEL	GEORGETOWN-HELBIG 230 FTLO NELSON-HARTBURG 500	97744,97696	97916,97717	402	FG_118
HM230_WEBWLS	HAMMOND 230/115 FTLO WEBRE-WELLS 500	98483,98484	98430,98109	168	FG_119
HSBIS_DOLSWS	HOT SPRINGS-BISMARK 115 FTLO DOLET HILLS-SOUTHWEST SHREVEPORT 345	99403,99397	50045,53454	98	FG_120
HSBIS_ELDXF	HOT SPRINGS-BISMRAK 115 FTLO ELDORADO EHV 500/345	99403,99397	99295,99294	98	FG_121
HSEBIS_MCETT	HOT SPRINGS BISMARK 115 FTLO ETTA-MCNEIL 500	99403,99397	99441,99309	98	FG_122
HSETA_SHDELD	HOT SPRINGS-ETTA 500 FTLO SHERIDAN-ELDORADO EHV 500	99402,99441	99333,99295	2165	FG_123
HUMGB_WATXF	HUMPHRY-GIBSON 115 FTLO WAT 230/500	98520,98521	98537,98539	227	FG_124

INDDELL500	INDEPENDENCE-DELL 500 KV PTDF	99818,99742		1732	FG_125
INDNEW1_DELL	INDEPENDENCE-NEWPORT 161 #1 FTLO INDEPENDENCE-DELL 500	99817,99764	99818,99742	417	FG_126
INDNEW2_DELL	INDEPENDENCE-NEWPORT 161 #2 FTLO INDEPENDENCE-DELL 500	99817,99764	99818,99742	417	FG_127
JACPC_GRICRO	JACINTO-PEACH CREEK 138 FTLO CROCKETT-GRIMES 345	97476,97543	53526,97513	191	FG_128
JACPC_JACSPL	JACINTO-PEACH CREEK 138 FTLO JACINTO-SPLENDORA 138	97476,97543	97476,97534	191	FG_129
JACSPL_ADL53	JACINTO-SPLENDORA 138 FTLO DAYTON-LINE 533 TAP	97476,97534	97632,97723	206	FG_130
JACSPL_CONLW	JACINTO-SPLENDORA 138 FTLO LEWIS CREEK-CONAIR 138	97476,97534	97461,97458	206	FG_131
JAKFL_JAKGE	JACKSON SOUTH-FLORENCE FTLO SOUTH JACKSON-POPLAR SPRINGS	98899,98955	98899,99093	160	FG_132
JIMREC_MADDE	JIM HILL-RECTOR NORTH 161 FTLO NEW MADRID-DELL 500	99753,99842	96035,99742	334	FG_133
JONHE_JONJOS	JONESBORO-HERGETT 161 FTLO JONESBORO-JONESBORO SPA	99755,52620	99755,52618	148	FG_134
JONJB_INDDEL	JONESBORO-JONESBORO SPA 161 FTLO INDEPENDENCE-DELL 500	99755,52618	99818,99742	223	FG_135
JONJON_JONHE	JONESBORO-JONESBORO SPA161-FTLO-JONESBORO-HERGET	99755,52618	99755,52620	223	FG_136
JSFL_BGFRK_D	JACKSON SOUTH-FLORENCE 115 FTLO BOGALUSA-FRANKLIN 500	98899,98955	98487,99027	160	FG_137
JSFLO_BOGFRK	JACKSON SOUTH-FLORENCE 115 FTLO FRANKLIN-BOGALUSA 500	98899,98955	99027,98487	160	FG_138
JSFLO_MCKFRK	JACKSON SOUTH-FLORENCE 115 FTLO FRANKLIN-MCKNIGHT 500	98899,98955	99027,98235	160	FG_139
KEOWH_SHRWH	WHITE BLUFF-KEO 500 FTLO WHITE BLUFF-SHERIDAN 500	99340,99627	99340,99333	1732	FG_140
LACSTW_LACWG	LACYGNE-STILWELL 345 FTLO LACYGNE-WGRN 345	57981,57968	57981,57965	2277	FG_141
LAKXF_RABLO	LAKEOVER115/500 FTLO LAKEOVER-RAY BRASWELL 500	98935,98936	98935,98930	600	FG_142
LASTHM_RCWEB	THOMAS-LA. STATION 138 FTLO WEBRE-WELLS 500	98236,98302	98430,98109	185	FG_143
LASTHM_WEBWL	THOMAS-LA. STATION 138 FTLO CAJUN-WEBRE 500	98236,98302	97301,98430	185	FG_144
LASWIL_WEBWL	LA. STATION-WILBURT 138 FTLO WEBRE-WELLS 500	98302,98411	98430,98109	308	FG_145
LCHTOL_GRICR	LEACH-TOLEDO 138 FTLO GRIMES-CROCKET 345	97708,97686	53526,97513	145	FG_146
LEVMUR_SYVSW	NLR LEVY-MURRAY 115 FTLO SYLVAN HILLS-SHERWOOD 115	99581,99576	99587,99586	159	FG_147
LEWALD_CONLE	LEWIS CREEK-ALDEN 138 FTLO LEWIS CREEK-CONAIR 138	97461,97544	97461,97458	411	FG_148
LEWALD_CONPL	LEWIS CREEK-ALDEN 138 FTLO CONROE-PLANTATION 138	97461,97544	97459,97465	411	FG_149
LEWPAT_GRICR	LEWIS CREEK-PATMOS 115 FTLO CROCKET-GRIMES 345	97461,97464	53526,97513	159	FG_150
LGPFVW_MCKFR	LITTLE GYPSY-FAIRVIEW 230 FTLO MCKNIGHT-FRANKLIN 500	98555,98498	98235,99027	454	FG_151
LGPPT_WFNINE	LITTLE GYPSY-PONCHARTRAIN FTLO WATERFORD-NINE MILE 230	98555,98589	98537,98606	570	FG_152
LGPSNO_WFNIN	LITTLE GYPSY-SOUTH NORCO FTLO WATERFORD-NINE MILE 230	98555,98557	98537,98606	796	FG_153
LRGNWG_MBLXF	NLR WESTGATE-LR GAINES 115 FTLO MABELVALE 500/115	99582,99543	99565,99566	159	FG_154
LTPLIV_WEBWL	LIVONIA-LINE 642 TAP 138 FTLO WEBRE-WELLS 500	98410,98147	98430,98109	289	FG_155
LULGYP_GYPXF	LITTLE GYPSY-LULING 115 FTLO LITTLE GYPSY 115/230	98554,98596	98554,98555	289	FG_156

LYNMCA_JASYL	LYNCH-MCALMONT 115 FTLO SYLVAN-JACKSONVILLE NORTH 115	99562,99573	99587,99534	261	FG_157
MABSH_WBSH	MABLEVALE-SHERIDAN 500 FTLO WHITE BLUFF-SHERIDAN	99565,99333	99340,99333	1732	FG_158
MABXF1_MAXF2	MABLEVALE 500/115 #1 FTLO MABLEVALE 500/115 #2	99565,99566	99565,99566	448	FG_159
MAIPMA_DHSW	MANSFIELD-MANSFIELD IP 138 FTLO DOLET HILLS-SOUTHWEST SHREVEPORT 345	50113,50090	50045,53454	232	FG_160
MARHRS_NEWIN	MARKED TREE-HARRISBURG FTLO NEWPORT-NEWPORT INDUSTRIAL 161	99761,99750	99764,99763	148	FG_161
MAYXF1_XF2	MAYFLOWER 500/115 #1 FTLO MAYFLOWER 500/115 #2	99572,99571	99572,99571	420	FG_162
MCAD_LAKOV_D	MCADAMS 230/500 FTLO LAKEOVER-MCADAMS 500	98809,98808	98935,98808	560	FG_163
MCADMLAKOVR	LAKEOVER-MCADAMS 500 KV PTDF	98935,98808		1732	FG_164
MCADXF_LAKOV	MCADAMS 500/230 FTLO MCADAMS-LAKEOVER 500	98808,98809	98808,98935	560	FG_165
MCKFRK_WEBWL	MCKNIGHT-FRANKLIN 500 FTLO WEBRE-WELLS 500	98235,99027	98430,98109	1960	FG_166
MCNCH_HSETTA	MCNEIL-COUCH 115 FTLO ETTA-HOT SPRINGS EHV 500	99310,99230	99441,99402	240	FG_167
MCNCOU_HSFRI	MCNEIL-COUCH 115 FTLO HOT SPRINGS-FRIENDSHIP	99310,99230	99403,99407	240	FG_168
MCNST_SMKELD	MCNEIL-STEPHENS 115 FTLO ELDORADO EHV-SMACKOVER 115	99310,99278	99293,99277	159	FG_169
MCNSTE_ELDXF	MCNEIL-STEPHENS 115 FTLO ELDORADO 500/115	99310,99278	99295,99293	159	FG_170
MDCPNB_SABXF	PORT NECHES BULK-MID COUNTY 138 FTLO SABINE 138/230	97843,97842	97705,97716	288	FG_171
MICFRO_MCKFR	MICHOUD-FRONT STREET FTLO MCKNIGHT-FRANKLIN 500	98652,50070	98235,99027	641	FG_172
MOHTB_WBWL_D	HARTBURG-MT. OLIVE 500 FTLO WEBRE-WELLS 500	97717,99162	98430,98109	1732	FG_173
MOLIVEHARTBG	MT. OLIVE-HARTBURG 500 KV PTDF	99162,97717		1732	FG_174
MORGL_ARKMAB	MORRILTON EAST-GLEASON 161 FTLO ANO-MABLEVALE 500	99507,99508	99486,99565	223	FG_175
MOSMAR_CARBT	MOSSVILLE-MARSHAL 138 FTLO CARLYSS-BIG THREE 230	97929,98043	97921,97925	159	FG_176
MTO230_MTELD	MT. OLIVE 230/115 FTLO ELDORADO EHV-MT. OLIVE 500	99163,99164	99295,99162	300	FG_177
MTOHTB_WEBWL	MT. OLIVE-HARTBURG 500 FTLO WEBRE-WELLS 500	99162,97717	98430,98109	1000	FG_178
MTOXF_STNELD	MT. OLIVE 230/115 FTLO ELDORADO-STERLINGTON 500	99163,99164	99295,99148	560	FG_179
MTZGRI_CROGR	MT. ZION - GRIMES 138 FTLO CROCKETT-GRIMES 345	97514,97487	53526,97513	206	FG_180
NATNATS_PLSF	NATCHEZ INDUSTRIAL-NATCHEZ SOUTH FTLO PLANTATION-SOUTH FERRIDAY	99022,99024	99117,99119	120	FG_181
NCRSCB_RICHR	NORTH CROWLEY-SCOTT 138 FTLO RICHARD-SCOTT 138	97329,98130	98108,98130	216	FG_182
NECSB_NECCAR	NECHES-CARROL STREET PARK 138 #1 FTLO NECHES-CARROL STREET PARK 138 #2	97702,97757	97702,97757	121	FG_183
NEL500_CARBT	NELSON 500/230 FTLO CARLYSS-BIG THREE	97917,97916	97921,97925	560	FG_184
NELLC_CARBOU	NELSON-LAKE CHARLES BULK 138 FTLO CARLYSS-BOUDIN 230	97918,97994	97921,98047	216	FG_185
NELLC_MOSNEL	NELSON LAKE CHARLES BULK 138 FTLO NELSON-MOSS BLUFF 230	97918,97994	97917,97302	216	FG_186
NELLC_NELLCB	NELSON-LAKE CHARLES BULK 138 #1 FTLO NELSON-LAKE CHARLES BULK 138 #2	97918,97994	97918,97994	159	FG_187
NELLC_RICNEL	LAKE CHARLES BULK-NELSON 138 FTLO RICHARD-NELSON 500	97994,97918	98107,97916	159	FG_188

NELXF_SABGTN	NELSON 500/230 FTLO GEORGETOWN-SABINE	97916,97917	97744,97716	560	FG_189
NELXF500	NELSON 500/230 PTDF	97916,97917		560	FG_190
NEWMADDELL	NEW MADRID-DELL 500 KV PTDF	96035,99742		1500	FG_191
NINMID_NAPOL	NINE MILE-DERBIGNY 230 FTLO NINE MILE-NAPOLEON 230	98606,98687	98606,98691	640	FG_192
NLRDXE_L145W	LR EAST-NLR DIXIE 115 FTLO WRIGHTSVILLE-LR 145TH STREET 115	99541,99580	99678,99538	159	FG_193
NLRLVWGLRKS	NLR LEVY-NLR WESTGATE 115 FTLO LR SOUTH-LR ROCK CREEK 115	99581,99582	99552,99551	159	FG_194
NMADEL_MARCU	NEW MADRID-DELL 500 FTLO MARHSALL-CUMBERLAND	96035,99742	18406,18425	1732	FG_195
NMADEL_SHWMA	NEW MADRID-DELL 500 FTLO SHAWNEE-MARSHALL	96035,99742	18401,18406	1732	FG_196
ORSAB_COWSAB	ORANGE-SABINE 138 FTLO COW-SABINE 138	97619,97705	97617,97705	216	FG_197
PACROS_ANIND	ROSEDALE-PACE 115 FTLO ANDRUS-INDIANOLA 230	98742,98741	98759,98769	85	FG_198
PACROS_INDBR	ROSEDALE-PACE 115 FTLO BRICKYARD-INDIANOLA 115	98742,98741	98836,98770	85	FG_199
PBSPIP_PBEIP	PB SOUTH-PB INTERNATIONAL PAPER 115 FTLO PB EAST-PB INTERNATIONAL PAPER 115	99326,99408	99324,99408	160	FG_200
PPGROB_VEPPG	PPG-ROSEBLUFF 230 FTLO PPG-VERDINE 230	97920,98046	97920,97919	470	FG_201
PPGROS_HBNEL	PPG ROSEBLUFF 230 FTLO NELSON-HARTBURG 500	97920,98046	97916,97717	470	FG_202
PPGROS_NELCL	PPG ROSEBLUFF 230 FTLO NELSON-CARLYSS 230	97920,98046	97917,97921	470	FG_203
QUTBEB_FTSAR	QUITMAN-BEE BRANCH 161 FTLO ANO-FT. SMITH 500	99519,99799	99486,55305	167	FG_204
RACCOT_TERXF	RACELAND-COTEAU 115 FTLO TERREBONNE 230/115	98512,98523	98510,98522	320	FG_205
RANPEL_ATTCA	RANKIN-PELAHATCHIE 115 FTLO ATTALA-CARTHAGE 115	98891,98881	98811,98817	261	FG_206
RANPEL_MCATL	RANKIN-PELAHATCHIE FTLO MCADAMS-ATTALA 230	98891,98881	98809,98810	261	FG_207
RAYBAX_GGFRA	BAXTER WILSON-RAY BRASWELL 500 FTLO GRAND GULF-FRANKLIN	98937,98930	98952,99027	1732	FG_208
RAYCLI_RAYLO	RAY BRASWELL 500/230 FTLO RAY BRASWELL-LAKEOVER	98930,98931	98930,98935	560	FG_209
RAYNAT_CHJAC	RAYWOOD-NATIONAL 138 FTLO CHINA-JACINTO 230	97626,97724	97714,97721	216	FG_210
RAYNAT_JACXF	RAYWOOD-NATIONAL 138 FTLO JACINTO 230/138	97626,97724	97478,97476	216	FG_211
RBCLN_RBLAK	RAY BRASWELL EHV-CLINTON 115 FTLO RAY BRASWELL EHV-LAKEOVER 500	98932,98911	98930,98935	240	FG_212
RBEHVLAKOVR	RAY BRASWELL-LAKEOVER 500 KV PTDF	98930,98935		1732	FG_213
RDSHL_BATEND	ROUNDAWAY-SHELBY 115 FTLO BATESVILLE-ENID 230	98725,98724	98729,98735	231	FG_214
RDSHL_INDXF	ROUNDAWAY-SHELBY 115 FTLO INDIANOLA 230/115	98725,98724	98769,98770	231	FG_215
RDSHL_MEPRIT	ROUNDAWAY-SHELBY 115 FTLO MEP CLARKSDALE-MOONLAKE 230	98725,98724	98854,99680	231	FG_216
RICCOL_FANCJ	RICHARD-COLONIAL ACADEMY 138 FTLO CAJUN-FANCY 500	98108,98110	97301,98233	209	FG_217
RICCOL_NCRIC	RICHARD-COLONIAL ACADEMY 138 FTLO RICHARD-NORTH CROWLEY 138	98108,98110	98108,97329	209	FG_218
RICCOL_SCOTT	RICHARD-COLONIAL ACADEMY FTLO RICHARD-SCOTT 138	98108,98110	98108,98130	209	FG_219
RICSTU_BRKRT	RICUSKEY-STUTTGART INDUSTRIAL 115 FTLO RITCHIE-BRINKLEY EAST	99646,99695	99651,99600	106	FG_220

RICXF1_XF2	RICHARD 500/138 #1 FTLO RICHARD 500/138 #2	98107,98108	98107,98108	625	FG_221
RILRIV_MTOEL	RILLA-RIVERTON 115 FTLO ELDORADO-MT. OLIVE 500	99126,99111	99295,99162	96	FG_222
RNGXF_ELDLGW	RINGGOLD 138/115 FTLO ELDORADO EHV-LONGWOOD 345	50024,99167	99294,53424	125	FG_223
ROWSHE_BATMO	SHELBY SWITCHING STATION-ROUNDAWAY 115 FTLO BATESVILLE-MOONLAKE 230	98724,98725	98729,99680	231	FG_224
RUSDAR_ANOFS	RUSSELVILLE SOUTH-DARDANVILLE DAM 161 FTLO ANO-FT. SMITH 500	99491,52708	99486,55305	335	FG_225
RUSDWN_STLEL	DOWNSVILLE-RUSTON 115 FTLO STERLINGTON-ELDORADO EHV 500	99160,97325	99148,99295	185	FG_226
RUSVIN_STLEL	RUSTON-VIENNA 115 FTLO ELDORADO EHV-STERLINGTON 500	97325,99161	99295,99148	239	FG_227
SABHAM_SABOI	SABINE-HAMPTON 138 FTLO SABINE-OILLA 138	97705,97701	97705,97789	282	FG_228
SABLIN_PNB	SABINE-LINDE 138 FTLO SABINE-PORT NECHES BULK	97705,97848	97705,97843	288	FG_229
SABOILL_HAMP	SABINE-OILLA 138 FTLO SABINE-HAMPTON 138	97705,97789	97705,97701	282	FG_230
SABPN_SABHAM	SABINE-PORT NECHES BULK 138 FTLO SABINE-HAMPTON 138	97705,97843	97705,97701	288	FG_231
SABPN_SABLI	SABINE-PORT NECHES BULK 138 FTLO SABINE-LINDE 138	97705,97843	97705,97848	288	FG_232
SAGMEL_ISDEL	SAGE SWITCHING STATION-MELBOURNE 161 FTLO INDEPENDENCE-DELL 500	99834,99824	99818,99742	148	FG_233
SCB_COCVILPL	SCOTT-BONIN 138 FTLO COCODRIE-VILLE PLATTE 230	98130,50304	50031,50203	225	FG_234
SCBON_MCKFR	SCOTT-BONIN 138 FTLO MCKNIGHT-FRANKLIN 500	98130,50304	98235,99027	225	FG_235
SCBON_MONCOL	SCOTT-BONIN 138 FTLO MONTGOMERY-COLFAX 230	98130,50304	99116,50033	225	FG_236
SCBON_WEBWLS	SCOTT-BONIN 138 FTLO WEBRE-WELLS 500	50304,98130	98430,98109	225	FG_237
SCSEM_SCBON	SCOTT-SEMERE 138 FTLO SCOTT-BONIN 138	98130,97323	98130,50304	130	FG_238
SCTBON_HABRI	SCOTT-BONIN 138 FTLO RICHARD-HABETZ 138	98130,50304	98108,50081	225	FG_239
SHEHMAG_ELEH	SHERIDAN-MAGNET COVE FTLO SHERIDAN-ELDORADO 500	99333,99450	99333,99295	1732	FG_240
SHEHV_MAGNET	SHERIDAN ELDORADO 50O FTLO SHERIDAN-MAGNET COVE	99333,99295	99333,99450	1732	FG_241
SHEWHB_MABWR	SHERIDAN-WHITEBLUFF 500 FTLO MABLEVALE-WRIGHTSVILLE	99333,99340	99565,99668	1732	FG_242
SHLDEL_INDXF	SHELBY-DELTA 115 FTLO INDIANOLA 230/115	98724,98737	98769,98770	87	FG_243
SHLDEL_MEPRI	DELTA-SHELBY 115 FTLO MOONLAKE-CROSSROADS 230	98737,98724	99680,98854	87	FG_244
SHRELD_HSPET	SHERIDAN-ELDORADO 500 FTLO HOT SPRINGS-ETTA 500	99333,99295	99402,99441	1732	FG_245
SHRMAB_KEO	SHERIDAN MABELVALE 500 FTLO WHITE BLUFF-KEO 500	99333,99565	99340,99627	1732	FG_246
SLIFB_DANMCK	FRENCH BRANCH-SLIDELL 230 FTLO DANIEL-MCKNIGHT 500	97327,98492	15021,98235	797	FG_247
SLVNHB_JACFL	SILVER CREEK-NORTH HEBRON FTLO JACKSON SOUTH-FLORENCE	99049,99050	98899,98955	161	FG_248
SOPJOL_NMNAP	SOUTHPORT-JOLIET 230 FTLO NINE MILE-NAPOLEON 230	98583,98655	98606,98691	640	FG_249
SORLUT_WGWAT	SORENTO LUTCHER 115 FTLO WILLOW GLEN WATERFORD 500	98546,98548	98246,98539	239	FG_250
SORVIG_MCKFR	VIGNES-SORRENTO 230 FTLO MCKNIGHT-FRANKLIN 500	97331,98544	98235,99027	462	FG_251
SREGON_WGWAT	SORRENTO-GONZALES 138 FTLO WILLOW GLEN-WATERFORD	98545,98268	98246,98539	130	FG_252

STLXF1_XF2	STERLINGTON 500/115 #1 FTLO STERLINGTON 500/115 #2	99148,99146	99148,99146	600	FG_253
SUMHE_BULSLD	SUMMIT-HARRISON EAST 161 FTLO BULL SHOALS-LEAD HILL 161	99837,99811	52660,99859	106	FG_254
SWFWAL_INDEL	SWIFTON-WALNUT RIDGE 161 FTLO INDEPENDENCE-DELL 500	99778,99765	99818,99742	167	FG_255
SYLSH_NLRMUR	SYLVAN-SHERWOOD 115 FTLO NLR LEVY-MURRAY TAP 115	99587,99586	99581,99576	159	FG_256
TALDEL_STLPV	TALULAH-DELHI 115 FTLO PERRYVILLE-STERLINGTON 500	99154,99155	99203,99148	80	FG_257
TBDVAN_ELMTO	TOLEDO-VAN PLY 138 FTLO ELDORADO-MT. OLIVE 500	97708,50199	99295,99162	289	FG_258
TBDVPL_MOHBG	VAN PLY-TOLEDO 138 FTLO MT. OLIVE-HARTBURG 500	50199,97708	99162,97717	289	FG_259
TBOGRN_WEBWL	TERREBONNE-GREENWOOD FTLO WEBRE-WELLS 500	98522,97309	98430,98109	227	FG_260
TERGRN_MCFRK	TERREBONNE-GREENWOOD 115 FTLO MCKNIGHT-FRANKLIN 500	98522,97309	98235,99027	227	FG_261
TERGRN_WEBCJ	TERREBONNE-GREENWOOD 115 FTLO CAJUN-WEBRE 500	98522,97309	97301,98430	227	FG_262
TERXF_WEBWLS	TERREBONNE 230/115 FTLO WEBRE-WELLS 500	98510,98522	98430,98109	300	FG_263
TERXF_VLNWAT	TERREBONNE 230/115 FTLO WATERFORD-VALENTINE 230	98510,98522	98537,98527	300	FG_264
TOLVP_MCKFRK	TOLEDO-VAN PLY 138 FTLO MCKNIGHT-FRANKLIN 500	97708,50199	98235,99027	289	FG_265
TOLVP_MONCOL	TOLEDO-VAN PLY 138 FTLO COLFAX-MONTGOMERY 230	97708,50199	50033,99116	289	FG_266
TUNRIT_RITTP	RITCHE-TUNICA 230 FTLO RITCHIE-MOONLAKE 230	99651,98718	99651,99680	462	FG_267
TUPTAP_VLPIT	TUPELO-TUPELO TAP 138 FTLO VAL PITTS 345	52800,56071	54037,54033	96	FG_268
VALTXF_RACWF	VALENTINE 230/115 FTLO WATERFORD-RACELAND 230	98527,98526	98537,98511	300	FG_269
VEPPG_PPGROB	PPG-VERDINE 230 FTLO PPG-ROSEBLUFF 230	97920,97919	97920,98046	470	FG_270
VERPPG_NELCS	VERDINE-PPG 230 FTLO NELSON-CARLYSS 230	97919,97920	97917,97921	470	FG_271
VKSWAT_BWXFM	WATERWAY-VICKSBURG 115 FTLO BAXTER WILSON 500/115	98946,98941	98937,98938	261	FG_272
VLNCH_COTHOU	VALENTINE-CHAUVIN 115 FTLO COTEAU-HOUMA 115	98526,98525	98523,98524	288	FG_273
VLNXF_VACTHB	VALENTINE 230/115 FTLO VACHERIE-THIBODAUX 230	98527,98526	98508,98509	300	FG_274
WALXF_INDDEL	WALNUT RIDGE 161/115 FTLO INDEPENDENCE-DELL 500	99784,99783	99818,99742	60	FG_275
WATFR_CONBAG	WATERFORD-FRISCO 230 FTLO CONWAY-BAGTELLE	98537,98566	98259,98569	440	FG_276
WATFR_WAT9MI	WATERFORD-FRISCO 230 FTLO WATERFORD NINE MILE 230	98537,98566	98537,98606	440	FG_277
WATFR_WATGYP	WATERFORD-FRISCO 230 FTLO WATERFORD-GYPSY 230	98537,98566	98537,98555	440	FG_278
WATFRI_WATWG	WATERFORD-FRISCO 230 FTLO WILLOW GLEN-WATERFORD 500	98537,98566	98246,98539	440	FG_279
WATGYP_WATGP	WATERFORD-LITTLE GYPSY 230 #1 FTLO WATERFOR-LITTLE GYPSY 230 #2	98537,98555	98537,98555	576	FG_280
WATNM_GYPSN	WATERFORD-NINEMILE 230 FTLO LITTLE GYPSY-SOUTH NORCO 230	98537,98606	98555,98557	640	FG_281
WATVKB_BWXFM	VICKSBURG EAST-WATERWAY 115 FTLO BAXTER WILSON 500/115	98867,98946	98937,98938	161	FG_282
WAWVIC_RABBA	WATERWAY-VICKSBURG EAST FTLO BAXTER WILSON-RAY BRASWELL	98946,98867	98937,98930	161	FG_283
WBWLS_MTHR_D	WEBRE-WELLS 500 FTLO HARTBURG-MT. OLIVE 500	98430,98109	99162,97717	1732	FG_284

WEBWL_MCKFRK	WEBRE-WELLS 500 FTLO MCKNIGHT-FRANKLIN 500	98430,98109	98235,99027	1732	FG_285
WEBWLS_MTHAR	WEBRE-WELLS 500 FTLO MT. OLIVE-HARTBURG 500	98430,98109	97717,99162	1732	FG_286
WEBWLS_STLPV	WEBRE-WELLS 500 FTLO STERLINGTON-PERRYVILLE	98430,98109	99203,99148	1732	FG_287
WEBERWELLS	WEBRE-WELLS 500 KV PTDF	98430,98109		1732	FG_288
WGATERF	WILLOW GLEN-WATERFORD 500 KV PTDF	98246,98539		1200	FG_289
WHBSHE_MABEL	WHITE BLUFF-SHERIDAN FTLO MABELVALE-SHERIDAN 500	99340,99333	99565,99333	1732	FG_290
WHBSHR_KEOWH	WHITE BLUFF-SHERIDAN 500 FTLO WHITE BLUFF-KEO 500	99340,99333	99340,99627	1732	FG_291
WILLVB_MCFRK	WILBURT-LIVONIA 138 FTLO MCKNIGHT-FRANKLIN 500	98411,98410	98235,99027	289	FG_292
WILLVB_WEBCJ	WILBURT-LIVONIA 138 FTLO CAJUN-WEBRE 500	98411,98410	97301,98430	289	FG_293
WILLVB_WEBWL	WILBURT LIVONIA 138 FTLO WEBRE-WELLS 500	98411,98410	98430,98109	289	FG_294
WINDOD_HARMT	WINNFIELD-DODSON 115 FTLO HARTBURG-MT. OLIVE 500	99112,99174	97717,99162	176	FG_295
WINDOD_MTCOL	WINNFIELD-DODSON 115 FTLO MONTGOMERY-COLFAX 230	99112,99174	99116,50033	176	FG_296
WINDOD_MTOXF	WINNFIELD-DODSON 115 FTLO MT. OLIVE 500/230	99112,99174	99162,99163	176	FG_297
WMPBIR_DELSH	WEST MEMPHIS-BIRMINGHAM STEEL FTLO DELL-SHELBY 500	99788,18051	99742,18008	2533	FG_298
WODPB_NLWRT	WOODWARD-PINE BLUFF DIERKS FTLO WRIGHTSVILLE-NLR 145TH STREET	99338,99323	99678,99538	98	FG_299
WYAPAR_MOELD	WYATT-PARNELL 115 FTLO ELDORADO-MT. OLIVE 500	99296,99412	99295,99162	159	FG_300
DOLXF_DOLSHR	DOLET 345/230 FTLO DOLET HILLS-SOUTHWEST SHREVEPORT 345	50045,50046	50045,53454	1056	FG_301
BONXF_FLNHPK	BONIN 230/138 FTLO FLANDERS-HOPKINS 138	50303,50304	50059,50085	336	FG_302
BONXF_RICSCB	BONIN 230/138 FTLO RICHARD-SCOTT 138	50303,50304	98108,98130	336	FG_303
SCBSEM_PNTBO	SCOTT-SEMERE 138 FTLO PONT DES MOUTON-BONIN 230	98113,97323	50310,50303	130	FG_304
SCBSEM_BOCEC	SCOTT-SEMERE 138 FTLO BONIN-CECELIA 138	98113,97324	50304,98190	130	FG_305
SCBSEM_WLPNT	SCOTT-SEMERE 138 FTLO WELLS-PONT DES MOUTON 230	98113,97325	50216,50310	130	FG_306
SCBSEM_WELXF	SCOTT-SEMERE 138 FTLO WELLS 500/230	98113,97326	98109,50217	130	FG_307
SRNVIG_SGAAC	VIGNES-SORRENTO 230 FTLO POLSCAR (ST. GABRIEL)-A.A.C. 230	97331,98544	98434,98249	462	FG_308
SCBBON_WLPNT	SCOTT-BONIN 138 FTLO WELLS-PONT DES MOUTON 230	98130,50304	50216,50310	225	FG_309
NRCSCB_WLPNT	NORTH CROWLEY-SCOTT 138 FTLO WELL-PONT DES MOUTON 230	97329,98130	50216,50310	216	FG_310
BONCEC_RICCO	BONIN-CECELIA 138 FTLO RICHARD-COLONIAL ACADEMY 138	50304,98190	98108,98110	145	FG_311
MONALC_SGAAC	ALCHEM-MONOCHEM 138 FTLO POLSCAR (ST. GABRIEL)-A.A.C. 230	98255,98271	98434,98249	225	FG_312
CLYVIG_SGAAC	COLY-VIGNES 230 FTLO POLSCAR (ST. GABRIEL)-A.A.C. 230	98391,97331	98434,98249	462	FG_313
SGAAC_CLYVIG	POLSCAR (ST. GABRIEL) 230-A.A.C. FTLO COLY-VIGNES 230	98434,98249	98931,97331	685	FG_314
ANDRXF_ANIND	ANDRUS 230/115 FTLO ANDRUS-INDIANOLA 230	98759,98760	98759,98769	392	FG_315
VKBVKW_BWSEV	VICKSBURG-VICKSBURG WEST 115 FTLO BAXTER WILSON-SOUTH EAST VICKSBURG 115	98941,98942	98938,98866	161	FG_316

9MILE_PMAX	9MILE_PMAX	FG_600
9MILE_PMIN	9MILE_PMIN	FG_601
ACADIA_PMAX	ACADIA_PMAX	FG_602
ACADIA_PMIN	ACADIA_PMIN	FG_603
AECI_TIECAPE	EXPORT LIMT FOR AECI INTERFACE	FG_604
AECI_TIECAPI	IMPORT LIMT FOR AECI INTERFACE	FG_605
AIRLIQU_PMAX	AIRLIQU_PMAX	FG_606
AIRLIQU_PMIN	AIRLIQU_PMIN	FG_607
AMRN_TIECAPE	EXPORT LIMT FOR AMRN INTERFACE	FG_608
AMRN_TIECAPI	IMPORT LIMT FOR AMRN INTERFACE	FG_609
ANDRUS_PMAX	ANDRUS_PMAX	FG_610
ANDRUS_PMIN	ANDRUS_PMIN	FG_611
ANO_PMAX	ANO_PMAX	FG_612
ANO_PMIN	ANO_PMIN	FG_613
ATTALA_PMAX	ATTALA_PMAX	FG_614
ATTALA_PMIN	ATTALA_PMIN	FG_615
BAILEY_PMAX	BAILEY_PMAX	FG_616
BAILEY_PMIN	BAILEY_PMIN	FG_617
BASF_PMAX	BASF_PMAX	FG_618
BASF_PMIN	BASF_PMIN	FG_619
BATESVI_PMAX	BATESVI_PMAX	FG_620
BATESVI_PMIN	BATESVI_PMIN	FG_621
BAXTER_PMAX	BAXTER_PMAX	FG_622
BAXTER_PMIN	BAXTER_PMIN	FG_623
BAYOUCO_PMAX	BAYOUCO_PMAX	FG_624
BAYOUCO_PMIN	BAYOUCO_PMIN	FG_625
BCAJUN1_PMAX	BCAJUN1_PMAX	FG_626
BCAJUN1_PMIN	BCAJUN1_PMIN	FG_627
BCAJUN2_PMAX	BCAJUN2_PMAX	FG_628
BCAJUN2_PMIN	BCAJUN2_PMIN	FG_629
BLAKLEY_PMAX	BLAKLEY_PMAX	FG_630

BLAKLEY_PMIN	BLAKLEY_PMIN	FG_631
BORDEN_PMAX	BORDEN_PMAX	FG_632
BORDEN_PMIN	BORDEN_PMIN	FG_633
CARBON_PMAX	CARBON_PMAX	FG_634
CARBON_PMIN	CARBON_PMIN	FG_635
CARPDAM_PMAX	CARPDAM_PMAX	FG_636
CARPDAM_PMIN	CARPDAM_PMIN	FG_637
CARVILL_PMAX	CARVILL_PMAX	FG_638
CARVILL_PMIN	CARVILL_PMIN	FG_639
CHEVOAK_PMAX	CHEVOAK_PMAX	FG_640
CHEVOAK_PMIN	CHEVOAK_PMIN	FG_641
CHOCTAW_PMAX	CHOCTAW_PMAX	FG_642
CHOCTAW_PMIN	CHOCTAW_PMIN	FG_643
CITGOCS_PMAX	CITGOCS_PMAX	FG_644
CITGOCS_PMIN	CITGOCS_PMIN	FG_645
CLARKS_PMAX	CLARKS_PMAX	FG_646
CLARKS_PMIN	CLARKS_PMIN	FG_647
CLEC_TIECAPE	EXPORT LIMT FOR CLEC INTERFACE	FG_648
CLEC_TIECAPI	IMPORT LIMT FOR CLEC INTERFACE	FG_649
COTTONW_PMAX	COTTONW_PMAX	FG_650
COTTONW_PMIN	COTTONW_PMIN	FG_651
COUCH_PMAX	COUCH_PMAX	FG_652
COUCH_PMIN	COUCH_PMIN	FG_653
CROSSRO_PMAX	CROSSRO_PMAX	FG_654
CROSSRO_PMIN	CROSSRO_PMIN	FG_655
CSWS_TIECAPE	EXPORT LIMT FOR CSWS INTERFACE	FG_656
CSWS_TIECAPI	IMPORT LIMT FOR CSWS INTERFACE	FG_657
DEGRAY_PMAX	DEGRAY_PMAX	FG_658
DEGRAY_PMIN	DEGRAY_PMIN	FG_659
DELLTPS_PMAX	DELLTPS_PMAX	FG_660
DELLTPS_PMIN	DELLTPS_PMIN	FG_661
DELTA_PMAX	DELTA_PMAX	FG_662

DELTA_PMIN	DELTA_PMIN	FG_663
DENL_TIECAPE	EXPORT LIMT FOR DENL INTERFACE	FG_664
DENL_TIECAPI	IMPORT LIMT FOR DENL INTERFACE	FG_665
DERS_TIECAPE	EXPORT LIMIT FOR DERS INTERFACE	FG_666
DERS_TIECAPI	IMPORT LIMT FOR DERS INTERFACE	FG_667
DOWCHEM_PMAX	DOWCHEM_PMAX	FG_668
DOWCHEM_PMIN	DOWCHEM_PMIN	FG_669
DUKEHIN_PMAX	DUKEHIN_PMAX	FG_670
DUKEHIN_PMIN	DUKEHIN_PMIN	FG_671
DYNCALC_PMAX	DYNCALC_PMAX	FG_672
DYNCALC_PMIN	DYNCALC_PMIN	FG_673
DYNOUAC_PMAX	DYNOUAC_PMAX	FG_674
DYNOUAC_PMIN	DYNOUAC_PMIN	FG_675
EDE_TIECAPE	EXPORT LIMT FOR EDE INTERFACE	FG_676
EDE_TIECAPI	IMPORT LIMT FOR EDE INTERFACE	FG_677
EXNENCO_PMAX	EXNENCO_PMAX	FG_678
EXNENCO_PMIN	EXNENCO_PMIN	FG_679
EXNESSO_PMAX	EXNESSO_PMAX	FG_680
EXNESSO_PMIN	EXNESSO_PMIN	FG_681
EXNEXXO_PMAX	EXNEXXO_PMAX	FG_682
EXNEXXO_PMIN	EXNEXXO_PMIN	FG_683
FORMOSA_PMAX	FORMOSA_PMAX	FG_684
FORMOSA_PMIN	FORMOSA_PMIN	FG_685
FRONTIE_PMAX	FRONTIE_PMAX	FG_686
FRONTIE_PMIN	FRONTIE_PMIN	FG_687
GEORGUL_PMAX	GEORGUL_PMAX	FG_688
GEORGUL_PMIN	GEORGUL_PMIN	FG_689
GRANDGU_PMAX	GRANDGU_PMAX	FG_690
GRANDGU_PMIN	GRANDGU_PMIN	FG_691
GYPSY_PMAX	GYPSY_PMAX	FG_692
GYPSY_PMIN	GYPSY_PMIN	FG_693
HOTSPRN_PMAX	HOTSPRN_PMAX	FG_694

HOTSPRN_PMIN	HOTSPRN_PMIN	FG_695
HUNTSMA_PMAX	HUNTSMA_PMAX	FG_696
HUNTSMA_PMIN	HUNTSMA_PMIN	FG_697
HYDRO2_PMAX	HYDRO2_PMAX	FG_698
HYDRO2_PMIN	HYDRO2_PMIN	FG_699
HYDRO9_PMAX	HYDRO9_PMAX	FG_700
HYDRO9_PMIN	HYDRO9_PMIN	FG_701
ISES_PMAX	ISES_PMAX	FG_702
ISES_PMIN	ISES_PMIN	FG_703
LAFA_TIECAPE	EXPORT LIMT FOR LAFA INTERFACE	FG_704
LAFA_TIECAPI	IMPORT LIMT FOR LAFA INTERFACE	FG_705
LAGN_TIECAPE	EXPORT LIMT FOR LAGN INTERFACE	FG_706
LAGN_TIECAPI	IMPORT LIMT FOR LAGN INTERFACE	FG_707
LAST1A_PMAX	LAST1A_PMAX	FG_708
LAST1A_PMIN	LAST1A_PMIN	FG_709
LEPA_TIECAPE	EXPORT LIMT FOR LEPA INTERFACE	FG_710
LEPA_TIECAPI	IMPORT LIMT FOR LEPA INTERFACE	FG_711
LEWIS_PMAX	LEWIS_PMAX	FG_712
LEWIS_PMIN	LEWIS_PMIN	FG_713
LKCATH_PMAX	LKCATH_PMAX	FG_714
LKCATH_PMIN	LKCATH_PMIN	FG_715
LSPR_TIECAPE	EXPORT LIMT FOR LSPR INTERFACE	FG_716
LSPR_TIECAPI	IMPORT LIMT FOR LSPR INTERFACE	FG_717
LYNCH_PMAX	LYNCH_PMAX	FG_718
LYNCH_PMIN	LYNCH_PMIN	FG_719
MABLVAL_PMAX	MABLVAL_PMAX	FG_720
MABLVAL_PMIN	MABLVAL_PMIN	FG_721
MCADAMS_PMAX	MCADAMS_PMAX	FG_722
MCADAMS_PMIN	MCADAMS_PMIN	FG_723
MCCLELL_PMAX	MCCLELL_PMAX	FG_724
MCCLELL_PMIN	MCCLELL_PMIN	FG_725
MICHOUD_PMAX	MICHOUD_PMAX	FG_726

MICHOUD_PMIN	MICHOUD_PMIN	FG_727
MIDSTRE_PMAX	MIDSTRE_PMAX	FG_728
MIDSTRE_PMIN	MIDSTRE_PMIN	FG_729
MONROE_PMAX	MONROE_PMAX	FG_730
MONROE_PMIN	MONROE_PMIN	FG_731
MOSES_PMAX	MOSES_PMAX	FG_732
MOSES_PMIN	MOSES_PMIN	FG_733
MURRY_PMAX	MURRY_PMAX	FG_734
MURRY_PMIN	MURRY_PMIN	FG_735
MURY_PMAX	MURY_PMAX	FG_736
MURY_PMIN	MURY_PMIN	FG_737
NATCHEZ_PMAX	NATCHEZ_PMAX	FG_738
NATCHEZ_PMIN	NATCHEZ_PMIN	FG_739
NELSON_PMAX	NELSON_PMAX	FG_740
NELSON_PMIN	NELSON_PMIN	FG_741
OKGE_TIECAPE	EXPORT LIMT FOR OKGE INTERFACE	FG_742
OKGE_TIECAPI	IMPORT LIMT FOR OKGE INTERFACE	FG_743
OXYTAFT_PMAX	OXYTAFT_PMAX	FG_744
OXYTAFT_PMIN	OXYTAFT_PMIN	FG_745
PATTRSO_PMAX	PATTRSO_PMAX	FG_746
PATTRSO_PMIN	PATTRSO_PMIN	FG_747
PBENERG_PMAX	PBENERG_PMAX	FG_748
PBENERG_PMIN	PBENERG_PMIN	FG_749
PPG_PMAX	PPG_PMAX	FG_750
PPG_PMIN	PPG_PMIN	FG_751
REXBROW_PMAX	REXBROW_PMAX	FG_752
REXBROW_PMIN	REXBROW_PMIN	FG_753
RITCH_PMAX	RITCH_PMAX	FG_754
RITCH_PMIN	RITCH_PMIN	FG_755
RIVERBN_PMAX	RIVERBN_PMAX	FG_756
RIVERBN_PMIN	RIVERBN_PMIN	FG_757
RSCOGEN_PMAX	RSCOGEN_PMAX	FG_758

RSCOGEN_PMIN	RSCOGEN_PMIN	FG_759
RUSTON_PMAX	RUSTON_PMAX	FG_760
SABCOGE_PMAX	SABCOGE_PMAX	FG_761
SABCOGE_PMIN	SABCOGE_PMIN	FG_762
SABINE_PMAX	SABINE_PMAX	FG_763
SABINE_PMIN	SABINE_PMIN	FG_764
SAMRAYB_PMAX	SAMRAYB_PMAX	FG_765
SAMRAYB_PMIN	SAMRAYB_PMIN	FG_766
SILVERC_PMAX	SILVERC_PMAX	FG_767
SILVERC_PMIN	SILVERC_PMIN	FG_768
SMEP_TIECAPE	EXPORT LIMT FOR SMEP INTERFACE	FG_769
SMEP_TIECAPI	IMPORT LIMT FOR SMEP INTERFACE	FG_770
SOCO_TIECAPE	EXPORT LIMT FOR SOCO INTERFACE	FG_771
SOCO_TIECAPI	IMPORT LIMT FOR SOCO INTERFACE	FG_772
SOHAVEN_PMAX	SOHAVEN_PMAX	FG_773
SOHAVEN_PMIN	SOHAVEN_PMIN	FG_774
SPA_TIECAPE	EXPORT LIMT FOR SPA INTERFACE	FG_775
SPA_TIECAPI	IMPORT LIMT FOR SPA INTERFACE	FG_776
SPFREEP_PMAX	SPFREEP_PMAX	FG_777
SPFREEP_PMIN	SPFREEP_PMIN	FG_778
SRWCOGE_PMAX	SRWCOGE_PMAX	FG_779
SRWCOGE_PMIN	SRWCOGE_PMIN	FG_780
STRLAGN_PMAX	STRLAGN_PMAX	FG_781
STRLAGN_PMIN	STRLAGN_PMIN	FG_782
STRLNGT_PMAX	STRLNGT_PMAX	FG_783
STRLNGT_PMIN	STRLNGT_PMIN	FG_784
TOLEDO_PMAX	TOLEDO_PMAX	FG_785
TOLEDO_PMIN	TOLEDO_PMIN	FG_786
TOWM_PMIN	TOWM_PMIN	FG_787
TOWN_PMAX	TOWN_PMAX	FG_788
TVA_TIECAPE	EXPORT LIMT FOR TVA INTERFACE	FG_789
TVA_TIECAPI	IMPORT LIMT FOR TVA INTERFACE	FG_790

UCB_PMAX	UCB_PMAX				FG_791
UCB_PMIN	UCB_PMIN				FG_792
UNIONPP_PMAX	UNIONPP_PMAX				FG_793
UNIONPP_PMIN	UNIONPP_PMIN				FG_794
VFWPARK_PMAX	VFWPARK_PMAX				FG_795
VFWPARK_PMIN	VFWPARK_PMIN				FG_796
VULCAN_PMAX	VULCAN_PMAX				FG_797
VULCAN_PMIN	VULCAN_PMIN				FG_798
WARREN_PMAX	WARREN_PMAX				FG_799
WARREN_PMIN	WARREN_PMIN				FG_800
WASHING_PMAX	WASHING_PMAX				FG_801
WASHING_PMIN	WASHING_PMIN				FG_802
WATRFOR_PMAX	WATRFOR_PMAX				FG_803
WATRFOR_PMIN	WATRFOR_PMIN				FG_804
WHITEBL_PMAX	WHITEBL_PMAX				FG_805
WHITEBL_PMIN	WHITEBL_PMIN				FG_806
WILLOWG_PMAX	WILLOWG_PMAX				FG_807
WILLOWG_PMIN	WILLOWG_PMIN				FG_808
WOODSTO_PMAX	WOODSTO_PMAX				FG_809
WOODSTO_PMIN	WOODSTO_PMIN				FG_810
WRIGHTS_PMAX	WRIGHTS_PMAX				FG_811
WRIGHTS_PMIN	WRIGHTS_PMIN				FG_812
YAZOO_PMAX	YAZOO_PMAX				FG_813
YAZOO_PMIN	YAZOO_PMIN				FG_814
CARROLS_PMIN	CARROLS_PMIN				FG_815
CARROLS_PMAX	CARROLS_PMAX				FG_816
MAGNETC_PMIN	MAGNETC_PMIN				FG_817
MAGNETC_PMAX	MAGNETC_PMAX				FG_818
PUPP_TIECAPE	EXPORT LIMT FOR PUPP INTERFACE				FG_819
TEMP1	TEMPORARY FLOWGATE-NOT DEFINED				FG_900
TEMP2	STERLINGTON-OAK RIDGE 115 kV FTLO PERRYVILLE-BAXTER WILSON 500 Kv	99146,99157	99203,98937	80	FG_901

TEMP3	TEMPORARY FLOWGATE-NOT DEFINED	FG_902
TEMP4	TEMPORARY FLOWGATE-NOT DEFINED	FG_903
TEMP5	TEMPORARY FLOWGATE-NOT DEFINED	FG_904
TEMP6	TEMPORARY FLOWGATE-NOT DEFINED	FG_905
TEMP7	TEMPORARY FLOWGATE-NOT DEFINED	FG_906
TEMP8	TEMPORARY FLOWGATE-NOT DEFINED	FG_907
TEMP9	TEMPORARY FLOWGATE-NOT DEFINED	FG_908
TEMP10	TEMPORARY FLOWGATE-NOT DEFINED	FG_909

FRCC ATC METHODOLOGY DOCUMENT Approved by the FRCC EC November 4, 2003

FLORIDA RELIABILITY COORDINATING COUNCIL

FRCC ATC CALCULATION AND COORDINATION PROCEDURES

I INTRODUCTION

This document defines the Florida Reliability Coordinating Council's (FRCC) ATC Coordination Procedures including the methodology and criteria used to calculate ATC and TTC. The methodology as defined in this document applies to TTC and ATC calculations for the current state of distributed calculations by individual transmission providers. The methodology and criteria conform to North American Electric Reliability Council (NERC), Planning Standards I.E.1. Total and Available Transfer Capability, S1 and S2 and the measurements M1 – M4, and I.E.2. Transfer Capability Margins, Sl (CBM), S2 (TRM), and measurements M1-M8, and the Transmission Capability Margins and Their Use in ATC Determination White Paper approved by the NERC Adequacy Committee (AC) – July 14, 1999.

The FRCC Engineering Committee (EC) formed an ATC Task Force in 1996, whose initial charge included the development of an "FRCC Methodology for ATC Calculation" in both the operating and planning horizons. In July of 1999, the FRCC EC approved the scope document of the ATC Working Group, making the ATCWG a standing committee of the EC, instead of an Ad Hoc task force. The ATCWG is also responsible for coordination with and support of the FRCC Operating Committee (OC), and the FRCC Market Interface Committee (MIC). The ATCWG responsibilities include compliance assessment.

FRCC Coordination Procedures will continue to evolve as NERC Planning Standards and the OASIS standard and requirements change in response to the FERC's Order 2000. The FRCC ATCWG has a broad base of membership and will continue to develop and modify FRCC ATC Coordination Procedures to comply with FRCC, FERC, and NERC requirements.

The FRCC ATCWG has a page and file locations on the FRCC WEB site at: www.frcc.com. Important documents such, as FRCC ATCWG reports to the NERC ATCWG are available for download. The FRCC ATCWG maintains a current membership roster with names, phone numbers, email addresses, which is also available for review or download.

II. PRINCIPLES

A. NERC

The ATC calculation and coordination efforts in FRCC will be in accordance with the six principles for calculating and applying ATCs specified in the NERC ATC Document as follows:

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

2. ATC calculations must recognize the time-variant power flow conditions in 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 direction of transfers across the interconnected transmission 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 reasonably reflects the ATCs of the interconnected network.

5. ATC calculations must conform to NERC, Regional, and individual system Planning Standards and Operating Policies.

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

B. FRCC

1. ATC values will not be used by FRCC as an indication of system security or network reliability.

2. The FRCC ATCWG is responsible for coordinating regional ATC calculation methodology and models. ATC calculations will be done by individual transmission providers in the current state, and will transition to a centralized calculation by the ISO when such ISO becomes operational.

3. FRCC's only inter-regional interface is the FRCC/SERC. The transfer capability for this interface is determined and coordinated through joint studies between the interface owners conducted under the auspices of the Florida/Southern Planning Task Force. Contracts between the owners determine the allocation of this transfer capability. Currently, ATC postings are coordinated by the individual Transmission Providers/owners in SERC and FRCC.

4. The FRCC Security Coordinator (SC) has the responsibility of monitoring the peninsular Florida electric system and for calling for all necessary actions to insure the reliable operation of the grid, including all TLR actions. This SC function is provided by FPL as the real time agent for the FRCC.

5. Each FRCC Transmission Provider will have the responsibility to monitor and assess the facilities under its operational control to ensure that they are operated within the Transmission Provider's safety standards and reliability criteria and in compliance with NERC Planning Standards and Operating Policies, and " Security Process for the FRCC Bulk-Power Electric System". This responsibility includes adhering to the actions called by the FRCC Security Coordinator.

6. Each FRCC Transmission Provider will evaluate and quantify ATCs as limited by monitored facilities based on principles of "Network Response Method for ATC Determination" as found in Appendix A of the June, 1996, NERC document titled “Available Transfer Capability: Definitions and Determination” and in accordance NERC Standards and this FRCC ATC Calculation and Coordination Procedures document. [IE1.S1.M1.c]

7. Each FRCC Transmission Provider will determine ATC values with directly connected systems and all other commercially viable paths through the provider’s system in accordance with this FRCC ATC Calculation and Coordination Procedures document.

III DEFINITIONS:

The following definitions are based on NERC definitions, FERC definitions, and definitions developed by the FRCC ATCWG.

A. Available Transfer Capability (ATC)

The measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already committed uses.

B. Total Transfer Capability (TTC)

TTC is the total (first contingency) transfer capability between two control areas (or zones) using the "control area-to-control area" method detailed in NERC's 1996 document. All facilities should be assumed available in the base cases. Each FRCC interface TTC should be determined individually but simultaneous with all Existing Commitments and Firm Reserved (NRES) transactions.

C. Transmission Reliability Margin (TRM)

Transmission Reliability Margin (TRM) is the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and its associated effects on ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change. All transmission system users benefit from the preservation of TRM by transmission providers.

D. Existing Commitments (EC)

Existing Commitments in the Planning Horizon are the long term, firm transactions modeled in the FRCC 715 filing loadflow base cases, and any shorter term firm transactions included in ATCWG operating loadflow cases or data on the FRCC ftp site. In the Operating Horizon, Existing Commitments observed by Transmission Providers include those transactions confirmed or scheduled, as applicable, by individual Transmission Providers on their FLOASIS pages.

E. Security Coordinator (SC)

The FRCC has contracted with an agent to provide the Security Coordinator function for the region whose responsibility is to monitor the FRCC grid with a real-time security analysis process to ensure that the system is always operated within established normal and first contingency limits. The Security Coordinator has the authority to implement FRCC TLR procedures. Full responsibilities of the Security Coordinator are specified in the “Security Process for the FRCC Bulk-Power Electric System.”

F. Operations Planning Coordinator (OPC)

The FRCC has contracted with an agent to provide the Operations Planning Coordinator function for the expected operating conditions for the upcoming week, according to FRCC procedures. Full responsibilities of the Operations Planning Coordinator are specified in the “Security Process for the Bulk-Power Electric System.” All transmission providers participate in supplying data to the OPC and in responding to requests for changes in planned system outages.

G. Non-Recallable Reserved (NRES or firm-reserved)

Any non-recallable Transmission Service that has been reserved on the transmission providers system in addition to EC. Within the FRCC, NRES is referred to as firm-reserved transmission service.

H. Capacity Benefit Margin (CBM)

The amount of firm transmission transfer capability preserved for Load Serving Entities (LSE’s) on the host transmission system where their load is located, to enable access to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a LSE allows that entity to reduce its installed generating capacity below what may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission capacity preserved as CBM is intended to protect the LSE in times of emergency generation deficiencies.

I. Control Area

An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling its generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the Interconnection.

J. Interface

The interconnections between two control areas or two zones within the same control area (may also be used to describe a commercially viable pathway between control areas).

K. Non-recallable ATC (NATC or Firm)

For both the Operating and Planning horizons, TTC less TRM, less Existing Commitments (EC), less Firm Reserved Service (NRES) less Capacity Benefit Margin (CBM). Within the FRCC, NATC is referred to and posted as available firm transmission capability.

NATC = Firm = TTC - TRM - EC - NRES - CBM (see figure 1)

L. Recallable ATC (RATC or Non-firm)

For the Planning horizon, TTC less TRM*a, less Recallable Reserved Transmission Service (RRES), less EC, less NRES, less CBM*b. Within the FRCC RATC is referred to and posted as available non-firm transmission capability.

RATC = Non-firm = TTC - (TRM)*a - RRES - EC - NRES - (CBM)*b (see fig.1)

For the Operating horizon, TTC less TRM*c, less Recallable Scheduled Transmission Service (RSCH), less EC, less Firm Scheduled Transmission Service (NSCH), less CBM*d.

RATC = Non-firm = TTC - (TRM)*c - RSCH - EC - NSCH - (CBM)*d (see fig. 2)

where the coefficients a,b,c,d are values between 0 and 1 determined by individual transmission providers based upon reliability concerns.

M. Posted Path

FRCC transmission providers post all interfaces and commercially viable pathways consistent with the Standards and Protocol document adopted by the FERC. That is:

RegionCode/TransmissionProviderCode/ Control Area–Control Area/OptionalFrom-To(POR-POD)/Spare.

N. Zone

Where use of a single zone for the control area would improperly limit use of the transmission system, the control area may be divided into two or more zones to facilitate proper calculation of ATCs.

O. Operating Horizon

The Operating Horizon extends from next hour to one year in the future.

P. Planning Horizon

The Planning Horizon extends from year two to the limit of the FRCC databases (generally year two through ten)

IV FRCC ATC METHODOLOGY AND CRITERIA

The available transfer capability of pathways within the FRCC shall be determined using a network response method for ATC/TTC determination, and using the most current Databank loadflow base cases filed annually by the FRCC with FERC in the form 715 filing as a starting point, updated using data available from the OPC and best assumptions. These cases should have each Florida control area's generation dispatched economically to meet that control areas existing firm requirements including existing firm interchange commitments (EC). [IE1.S1.M1.b] In the Operating Horizon (next day to one year) the transmission providers in FRCC use cases developed by the ATCWG in the manner described above, that are stored in a common area available to transmission providers. These cases include at least 21 loadflows representing the week ahead, and monthly cases representing the next 12 months. The ATCWG daily cases are updated weekly, and the monthly cases are updated on a seasonal schedule. The criteria used for ATC calculations shall be consistent with the FRCC and individual utility criteria submitted in the latest FERC 715 filing. Established operating procedures shall be incorporated into ATC calculations. Revisions to operating procedure changes shall be noted and shared on the FRCC ftp site.

A. METHODOLOGY

1. FRCC OPC Loadflow Databank

Each FRCC Transmission Provider, in coordination with its respective LSE will develop current and next year peak summer and winter load flow cases and tables of interchange assumptions for EC and firm commitments at a variety of anticipated system load levels to facilitate transmission providers in the determination of TTC and ATC values. These “base cases” are derived from the peak load base cases that FRCC Transmission Working Group annually updates through the FERC 715 filing and represent seasonal load profiles, in-service generating units, in-service transmission facilities and firm interchange contracts according to NERC guidelines. [IE1.S1.M1.f,g,h]

2. Zones option

FRCC Transmission Providers may divide their transmission system(s) into zones to provide for commercially viable ATC results. Each transmission provider shall determine the zone designations within their respective control area, and report this information to the TWG for inclusion in the “base case” described in 1 above

3. FRCC ATC loadflow databank

The FRCC ATCWG uses cases developed in “1” above to create at least 21 loadflow cases for the next week (three per day) of planned operations, modeling the expected load levels, facility outages, and transactions identified in the weekly OPC conference call. In addition, the ATCWG provides monthly cases for the next 12 months that model the combination of highest load and worst maintenance outage scenario. The ATCWG modifies facility ratings in the cases as follows: For all transmission providers except FPC, rate b for all lines is copied to the rate c position, and the rate a is copied to the rate b position. For all utilities except FPC and FPL, the same procedure is used for transformers. This results in all lines and transformers having a rate a, b, and c, corresponding to continuous, long term emergency, and short term emergency loading limits respectively. In months with large variations in generator outages, two cases may be used, and the Transmission Providers use the more conservative case for the monthly ATC calculation. These cases are posted on the FRCC ftp site for use by transmission providers for ATC calculations. Data sets listing the outage data, firm transmission reservations, and other relevant information are also posted on the ftp site. [IE1.S1.M1.d,f,g,h]

4. CBM [IE2.S1.M1]

Each FRCC Transmission Provider makes an assessment of the CBM needed for its respective LSE's required on such transmission system, to enable access to generation from other interconnected systems to meet generation reliability requirements. Preservation of CBM for a LSE allows that entity to reduce its installed generating capacity below what may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission capacity preserved as CBM is intended to protect the LSE in times of emergency generation deficiencies.,. In determining the amount of CBM to be reserved either probabilistic or deterministic generation reliability analysis may be utilized. The computation of generation reliability requirement needs to be done in a manner consistent with its generation planning criteria. The FRCC TPs currently include their total load; therefore, interruptible demands are not utilized in determining CBM values. It is understood that only generation unit outages considered within a TP's system shall be utilized for determining CBM values unless a special provision is sought as provided for below. Should a Transmission Provider, on behalf of its LSE, find that it needs special provisions for CBM that is unique, it shall send a written request for review to the Chair of the ATCWG, who shall notice the members of the ATCWG, and convene a meeting if necessary to review the request for the exception. The FRCC ATCWG shall provide the requestor with a written response documenting the request, the decision of the ATCWG, and the rationale for the decision.

The appropriate amount of transmission interface capability is then reserved by the Transmission Provider for CBM on a per interface basis, taking into account the amount of generation available on other interconnected systems, the respective load peaking diversities of those systems, and TRM. Operating reserves may be included if appropriate in TRM and subsequently subtracted from the CBM needed. FRCC TPs do not include generation reserve sharing in CBM values.

The FRCC ATCWG shall conduct an annual review of the Transmission Providers documentation and procedures for calculating CBM on behalf of its respective LSE. This review shall be scheduled after filing of the annual FRCC L&RP, and shall be available on the FRCC WEB site. [IE2.S1.M3]

5. TRM [IE2.S2.M6]

Intra-Regional TRM

Each Transmission Provider individually determines the appropriate amount of TRM at each of its interfaces taking into account the facilities of other FRCC Transmission Providers by modeling, when appropriate, a generating unit off-line that is critical to that particular interface and computing the transfer capability obtained using either the most limiting contingency (line or generating unit (inertial response)) or FRCC operating reserves (ORes) scheduled in a loadflow due to the outage of the most limiting generating unit. Should there be no generating unit critical to the interface, a unit outage should be modeled, when appropriate, as ORes scheduled in a loadflow followed by single line or generator (inertial response) contingencies. The most restrictive of these transfer values is then subtracted from the TTC (with all generating units available) to arrive at the TRM. ORes is determined within FRCC by modeling each utility's allocated share of operating reserve requirements (for the particular unit to be modeled off-line) consistent with the latest FRCC Operating Reserve Policy. ORes is only applicable to intra-regional interfaces, and is considered a short-term operator response that ensures reliability of the Regional system.

To the extent that system conditions allow without adversely impacting reliability, TRM will be made available for transmission service on a nonfirm basis.

Inter-Regional TRM

The following owners (Florida Power and Light Company, Progress Energy Florida , andJEA) of the Inter-Regional interface of FRCC with SERC have developed a TRM methodology to coordinate their interface ATC postings on the Florida OASIS (FLOASIS). This TRM value represents the inertial response from SERC for the loss of a 500 MW Class generating unit in FRCC. Ninety percent of all generating units within FRCC are less than 500 MW. This TRM value provides a reasonable margin for the forced outage of generators which will affect the transfer capability of this interface as well as providing for the avoidance of frequent curtailments of firm transactions. This TRM methodology is consistent and similar to the methodology used by SERC entities in setting a TRM value on the SERC side of this interface for imports into SERC from FRCC. This methodology is also consistent with the FRCC criteria for intra-regional TRM, which allows for the sudden loss (inertial response) margin.
To the extent that system conditions allow without adversely impacting reliability, TRM will be made available for transmission service on a nonfirm basis.

Should a Transmission Provider, on behalf of its LSE, find that it needs special provisions for TRM that is unique, it shall send a written request for review to the Chair of the ATCWG, who shall notice the members of the ATCWG, and convene a meeting if necessary to review the request for the exception. The FRCC ATCWG shall provide the requestor with a written response documenting the request, the decision of the ATCWG, and the rationale for the decision.

The FRCC ATCWG shall conduct an annual review of the Transmission Providers' documentation and procedures for calculating TRM. This review shall be available on the FRCC WEB site. [IE2.S2.M8]

6. TTC

Using the appropriate base cases developed above, transfer limits are determined using facility ratings "b" for all commercially viable paths. [IE1.S1.M1.c] These transfer limits are based on first contingency conditions. The results are combined with the appropriate TRM, EC, NRES, and CBM to obtain the Total Transfer Capability (TTC). [IE1.S1.M1.a]

7. Firm ATC

Start with the appropriate base cases modeling all firm Scheduled (NSCH) and Reserved (NRES) transactions, Existing Commitments (EC), and appropriate import to represent CBM required by the Transmission Provider on behalf of its respective LSE for generation reliability.

In addition, each transmission provider individually models TRM as described in 5 above. Transfer limits based on first contingency conditions using facility ratings "b" are then determined for all commercially viable paths. [IE1.S1.M1.c] The results are firm ATC. Facility ratings "b" observe longer term facility ratings that are achievable for several hours. [IE1.S1.M1.a]

8. Non-firm ATC

Start with the appropriate cases modeling all scheduled and reserved transmission service. Each transmission provider, should model TRM as described above, and determine transfer limits using facility ratings "c". The results are non-firm ATC. Non-firm ATC calculations observe appropriate short term "c" facility ratings. [IE1.S1.M1.a]

9. Posting

Post the TTC, Firm, and Non-firm ATC values on the FLOASIS using the format required by the FERC. The CBM assumptions concerning power sources and sink shall be posted on the FLOASIS.
This FRCC ATC Methodology Document that details ATC methodology including TRM and CBM methodology shall be available on the FRCC web site in its latest approved version.

B. FRCC ATC CRITERIA[IE1.S1.M2]

The criteria used by transmission providers and those entities responsible for the calculation and posting of ATCs, shall be consistent with the latest version of the applicable NERC Planning Standards and Operating Policies, and with FRCC and the individual utility criteria included in the FRCC submittal of the FERC 715 filing.

1. Limiting Facilities:

A limiting facility must have an OTDF at or above 5% to be considered a valid limit to transfer, and need not reside in the transmission provider's system. The Outage Transfer Distribution Response Factor (OTDF) is the percentage of a power transfer that flows on a line for that particular transfer, during the outage of a critical facility. Exceptions to a 5% threshold are reviewed on a case-by-case basis by the ATCWG.

2. ATC Monitored Facilities List:

Monitored Facilities are those facilities that are monitored for overloads and low voltage conditions (limits) under normal or first contingency analysis when calculating NATC and RATC. Monitored Facilities for use in ATC calculations will generally include facilities operated at 69 kV and above' and all tie lines between Transmission Providers. Other facilities operated at lower voltage levels may be added to the Monitored Facilities list at the discretion of the Transmission Providers. The FRCC ATCWG is responsible for compilation of the Monitored Facilities list for the FRCC, and uses the current monitored facilities list for the FRCC Security Coordinator and FRCC Operations Planning Coordinator functions as a starting point. This list is posted on the FRCC ftp site.

3. ATC Critical Contingencies List:

Critical Contingencies are those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multi-terminal lines, or generating units. All tie-lines regardless of voltage and the largest unit of each control area will be considered Critical Contingencies. The FRCC ATCWG is responsible for compilation of the Critical Contingencies list for ATC calculations, and uses the current critical facilities list of the OC as a starting point. The ATC Critical Contingencies list is posted on the FRCC ftp site.

4. Commercially Viable Results:

FRCC Transmission providers shall observe the lower of thermal, voltage, or stability limits when determining ATC values for posting, and are expected to individually determine when voltage or stability limits may occur. In the network response methodology, transmission providers shall also post the lower of the calculated ATC value or their uncommitted contract path capacity on a posted path.

5. Netting Procedures: [IE1.S1.M1.i]

The FRCC region uses net scheduling to evaluate ATC for firm and non-firm reservations in that transactions are scheduled until lines flows are at their single contingency limits, or otherwise have reached the limit of contract path capacity. Reservations for contracted long-term firm transactions are netted in that they are modeled in annual basecase load flow models, and taken into consideration for determination of TTC and ATC values. Short-term firm reservations with a high degree of scheduling certainty are included in the weekly ATCWG cases and thus are netted in ATC calculations. Other short-term firm reservations are not normally netted due to the uncertainty as to whether such reservations will actually be scheduled.

V. FRCC COORDINATION PROCEDURES:

The following coordination procedures are used by the FRCC in determining its intra-regional and inter-regional transfer capabilities.

A. FRCC Data Exchange Coordination

1. FRCC member utilities jointly prepare on an annual basis a loadflow databank for a ten-year horizon containing annual winter and summer peak cases. This databank includes an interchange database for a variety of system load conditions and economic dispatch tables to facilitate preparation of loadflow cases for off-peak conditions. These loadflow databank cases are included with the FRCC submittal of the FERC 715 filing, and contain all long term firm transactions [IE1.S1.M1.b], individual utility generation dispatch, projected load for the time period under evaluation, planned generation or transmission facility additions in the future, and designation of generation resources to serve all network load. These cases provide the starting point for all ATC determination.

   The FRCC Planning cases above are modified to develop operating base cases for the timeframe under study between the next hour to up to one year in the future. Depending on the operating timeframe, the planning base cases are modified to reflect the load forecast for the timeframe under study, planned generation and transmission outages, forced generation or transmission outages, system constraints or equipment deratings, and reserved and scheduled firm purchase/sale transactions [IE1.S1.M1.b] on the transmission system. Operating cases developed by the ATCWG are posted on the FRCC ftp site for one year in the future, and include at the minimum 21 loadflows representing the future week, and monthly cases for the next 12 months.

2. On a seasonal basis, the FRCC ATCWG compiles a tabulation of the most active commercially viable common paths, requests the monthly firm and nonfirm ATC values from each transmission provider, and convenes a meeting to coordinate the ATC values to be posted. These meetings are typically scheduled in the spring for the upcoming summer season, and in the fall for the upcoming winter season. [IE1.S1.M3]

3. The FRCC Security Coordinator has the responsibility to monitor the FRCC grid with a real-time security analysis process to ensure that the system is always operated within established normal and first contingency limits. The Security Coordinator has the authority to order curtailment of transactions according to FRCC TLR procedures. Full responsibilities of the Security Coordinator are specified in the "Security Process for the FRCC Bulk-Power Electric System." In addition, for the short term operating timeframe, updates on generator outages, transmission outages, and system interchange are shared on the FRCC FTMS.

4. The FRCC Operations Planning Coordinator has the responsibility to evaluate system security for planned operations for future days two through seven, thus ensuring that planned maintenance outages and system configurations will not result in security problems that the Security Coordinator will have to deal with. The Operations Planning Coordinator has the authority to seek resolution with parties whose planned actions will affect system security. Full responsibilities of the Operations Planning Coordinator are specified in the "Security Process for the FRCC Bulk-Power Electric System." The OPC also obtains maintenance and reservations data which is shared with and posted by the ATCWG on the FRCC ftp site.

B. ATC Posting:

1. Intra-Regional Coordination: Postings are currently made using the FERC format by PEF, FPL, TEC, JEA, OUC, SEC, and TAL on a single node OASIS named FLOASIS (http://www.floasis.siemens-asp.com/). Other transmission providers are currently posting on an individual internet site, or developing such a site.

2. Inter-Regional Coordination: The FRCC Region is connected to the Eastern Interconnection only through its interface with the Southern Subregion of SERC. The FRCC/SERC interface is an allocated interface, with the ownership rights to the interface transfer capability determined by negotiated agreements filed at the FERC by the transmission providers that own interface facilities. These agreements specify operating and administrative arrangements, including the monitoring and control of interface transactions by an administrator assigned by the Administrative Committee. The Security Coordinator functions to assure that transactions are limited to the interface capability at all times, and to direct necessary adjustments when curtailments are required.

C. FRCC ATC Dispute Resolution Procedures

The responsibility for dispute resolution resides with the transmission provider, who may use any applicable tariff or contract processes. FRCC will consider the need for formal ATC dispute resolution procedures as the FRCC transmission providers gain experience in the marketplace.

D. Future FRCC ATC Coordination:

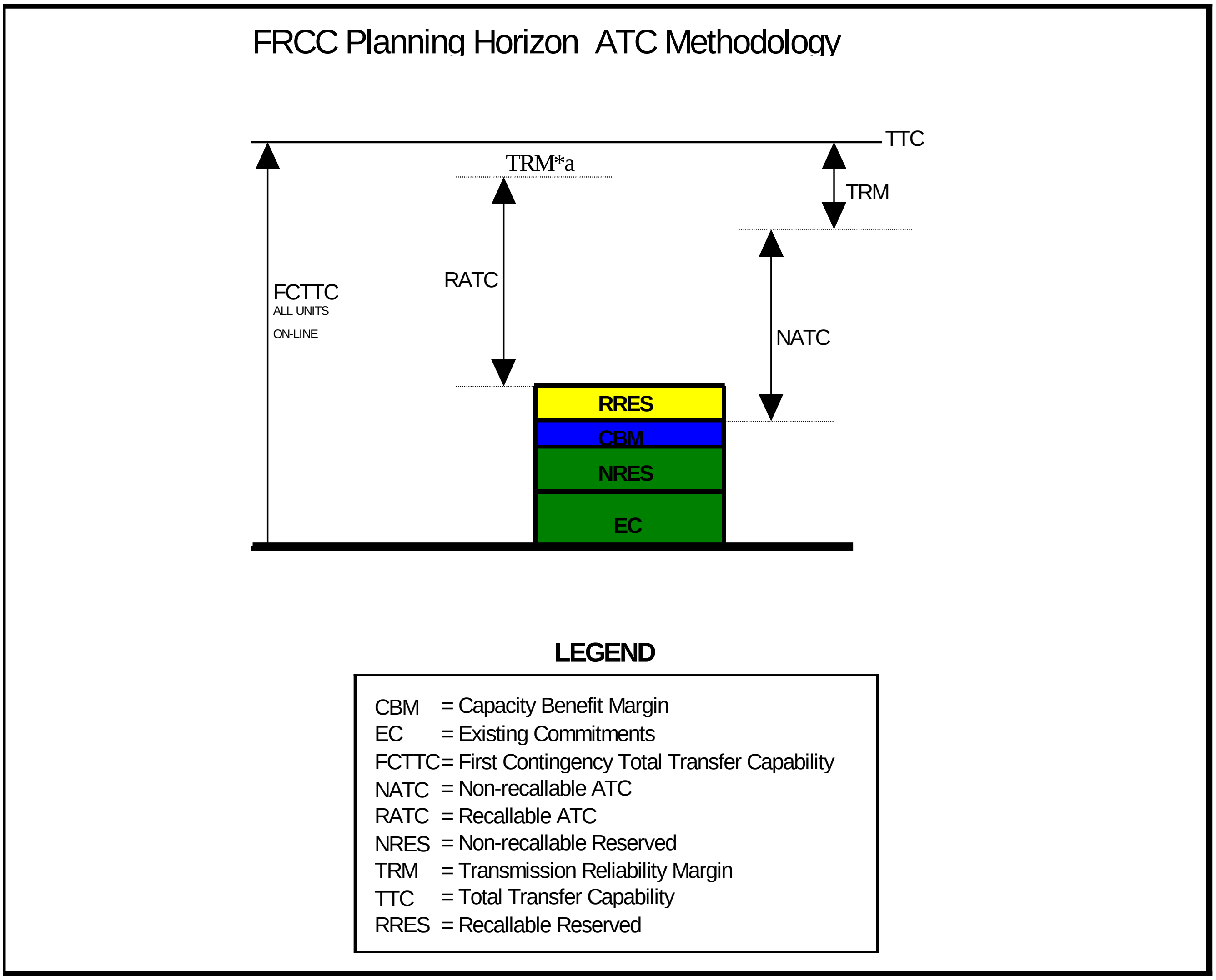
The FRCC ATCWG will modify and adjust the FRCC ATC Coordination document as required. The FRCC is committed to providing the required transmission information systems to facilitate the calculation and posting of commercially viable ATC values.

VI. APPENDICES

A. Figure 1

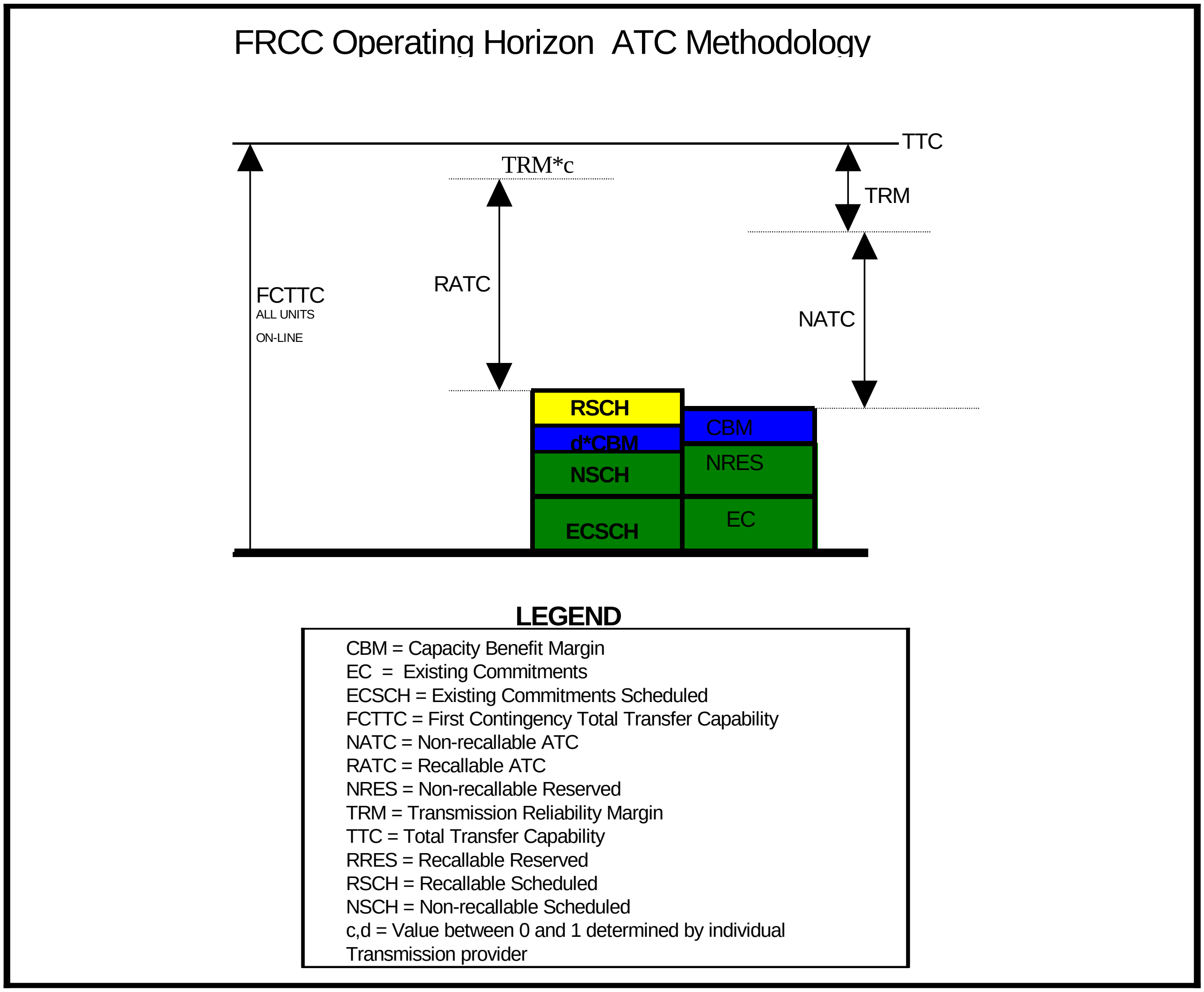
B. Figure 2

C. FRCC ATCWG Scope Document



Note 1: Depending on the Planning timeframe, RATC can vary depending on the required TRM and CBM. Coefficients a and b can be applied reducing the amount of TRM (TRM*a) or CBM (CBM*b). Coefficients a and b have values between 0 and 1 as determined by individual transmission providers.

Figure 1



(Is this a way to better explain this figure?)

Figure 2

C. ATCWG Scope Document (approved by the FRCC EC on 7/7/99)

PURPOSE

1. To provide a forum to facilitate procedures for Intraregional and Interregional coordination of ATC, and to ensure commercial viability of ATC postings.

2. To evaluate and report as required on the ATC calculation procedures of FRCC Transmission Providers to determine compliance with FRCC procedures.

3. To develop and monitor data sharing procedures among FRCC Transmission Providers.

4. To report to the FRCC Engineering Committee (EC) and NERC ATCWG on FRCC ATC Coordination Procedures as required.

5. To provide support to the FRCC Operating Committee (OC), Engineering Committee (EC), or Market Interface Committee (MIC) when required.

OBJECTIVES

1. Develop and maintain written FRCC ATC Coordination Procedures.

2. Maintain lists of Monitored Facilities, Outaged Facilities, and Commercially Viable Pathways.

3. Monitor OASIS postings to determine commercial Viability.

4. Maintain and update data on the FRCC FTP site for sharing of ATC coordination data.

5. Coordinate with the FRCC OPC to provide operating loadflow cases on the FTP site for use in ATC calculations.

6. Develop methodology and procedures for coordinated calculation of year two ATC's by the ATCWG. Determine feasibility of process.

7. Conduct and document reviews as required of ATC coordination procedures of FRCC Transmission Providers to determine compliance with FRCC and NERC planning standards and guides, and FRCC Operating Policies.

8. Provide reports on ATC Coordination to the NERC ATCWG and to the FRCC EC, OC, or MIC as required.

9. Ensure ATCWG membership includes adequate representation from Planning, Operating, Marketing, and other perspectives.

Item 4cii

FRCC ATCWG
CBM METHODOLOGY

FRCC Transmission Providers make an assessment of the CBM needed on their respective systems by using either deterministic or probabilistic generation reliability analysis. The appropriate amount of transmission interface capability is then reserved for CBM on a per interface basis, taking into account the amount of generation available on other interconnected systems, the respective load peaking diversities of those systems, and TRM. Operating reserves may be included if appropriate in TRM and subsequently subtracted from the CBM needed.

Approved 11/10/99
FRCC Engineering Committee

4.0 REGIONAL CALCULATION OF AVAILABLE TRANSFER CAPABILITY

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners. This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes. Likewise, when Transmission Owners calculate ATC, they are responsible to coordinate the ATC between their areas. If there is a dispute concerning the ATC, the SPP Transmission Working Group (TWG) will act as the technical body to determine the ATC to be reported.

This Criteria provides Transmission Owners and the SPP Transmission Provider flexibility to revise the ATC as needed for changes in operating conditions, while providing for unique modeling parameters of the areas. The SPP Transmission Provider calculations do not preclude any studies made by Transmission Owners in accordance with their individual tariffs, which may contain specific methodologies for evaluating transmission service requests.

Transfer capabilities are calculated for two different commercial business applications; a) for use as default values for Transmission Owners to post on their OASIS node for business under their transmission tariffs and b) for use by SPP in administering the SPP Open Access Transmission Tariff (SPP OATT).

The SPP utilizes a “constrained element” approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed “Flowgates”, used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using Flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (Flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes. Therefore, the SPP Operating Reliability Working Group and the SPP Transmission Working Group will have the joint authority to modify the implementation of this Section of the Criteria based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP By-laws at the first practical opportunity, with the exception of response factor thresholds for short-term transmission service which may be approved for immediate implementation by the ORWG subject to subsequent review by the MOPC at the first practical opportunity. The response factor thresholds for short-term and long-term service are included in Appendix 9.

4.1 DEFINITIONS

4.1.1 Base Loading, Firm and Non-Firm (FBL & NFBL)

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load and impacts from existing OATT OASIS commitments.

4.1.2 Capacity Benefit Margin

The amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

4.1.3 Contractual Limit

Contractual arrangements between Transmission Providers that define transfer capability between the two.

4.1.4 Critical Contingency

Any generation or transmission facility that, when outaged, is deemed to have an adverse impact on the reliability of the transmission network.

4.1.5 Designated Network Resources (DNR)

Any designated generation resource that can be called upon at anytime for the purpose of serving network load on a non-interruptible basis. The designated generation resource must be owned, purchased or leased by the owner of the network load.

4.1.6 Emergency Voltage Limits

The operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a Critical Contingency.

4.1.7 Firm Available Transfer Capability (FATC)

The determined transfer capability available for firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff (OATT) or any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.8 First Contingency Incremental Transfer Capability (FCITC)

NERC Transmission Transfer Capability, reference document (May 1995) defines FCITC as:

> "The amount of power, incremental and above normal base transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:
>
> 1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,
> 2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission circuit, transformer or generating unit, and,
> 3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facilities loadings are within emergency ratings and all voltages are within emergency limits."

4.1.9 Flowgate

A selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage, stability and contractual system constraints to power transfer. The process of determining the reliability issues for which a Flowgate is representative of and by which a Flowgate is established is outlined in the Flowgate Determination section.

4.1.10 Line Outage Distribution Factor (LODF)

The percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

4.1.11 Local Area Problem

A Transmission Owner may declare a facility under its control a Local Area Problem if it is overloaded in either the base case or contingency case prior to the transfer. If a member declares a facility a Local Area Problem, the member may neither deny transmission service nor request NERC Transmission Loading Relief for that defined condition.

4.1.12 Monitored Facilities

Any transmission facility that is checked for predefined transmission limitations.

4.1.13 Non-firm Available Transfer Capability (NFATC)

The determined transfer capability available for sale for non-firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff for any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.14 Normal Voltage Limits

The operating voltage range on the interconnected system that is acceptable on a sustained basis.

4.1.15 Open Access Transmission Tariff (OATT)

FERC approved Pro-Forma Open Access Transmission Tariff.

4.1.16 Operating Horizon

Time frame for which Hourly transmission service is offered. The rolling time frame is twelve to 36 hours with a 12 noon threshold. It includes the current day, and after 12 noon, the remainder of the current day and all hours of the following day.

4.1.17 Operating Procedure

Any policy, practice or system adjustment that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. If an Operating Procedure is submitted to the SPP in writing and states that it is an unconditional action to implement the procedure without regard to economic impacts or existing transfers, then the Operating Procedure will be used to allow transfers to a higher level.

4.1.18 Outage Transfer Distribution Factor (OTDF)

The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

4.1.19 Participation Factor

The percentage of the total power adjustment that a participation point will contribute when simulating a transfer.

4.1.20 Participation Points

Specified generators that will have their power output adjusted to simulate a transfer.

4.1.21 Planning Horizon

Time frame beyond which Hourly transmission service is not offered.

4.1.22 Power Transfer Distribution Factor (PTDF)

The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.

4.1.23 Power Transfer Voltage Response Factor (PTVF)

The per unit amount that a facility's voltage changes due to a particular transfer level.

4.1.24 SPP Open Access Transmission Tariff (SPP OATT)

The Southwest Power Pool Regional FERC approved Open Access Transmission Tariff

4.1.25 Transfer Distribution Factor (TDF)

A general term, which may refer to either PTDF or OTDF – The TDF represents the relationship between the participation adjustment of two areas and the Flowgates within the system.

4.1.26 Transfer Test Level

The amount of power that will be transferred to determine facility TDFs for use in DC linear analysis.

4.1.27 Transmission Owner (TO)

An entity that owns transmission facilities which are operated under a FERC approved OATT.

4.1.28 Transmission Provider (TP)

An entity responsible for administering a transmission tariff. In the case of the SPP OATT, SPP is the Transmission Provider. An SPP member may be its own Transmission Provider if the member continues to sell transmission service under the terms of its own tariff.

4.1.29 Transmission User (TU)

Any entities that are parties to transactions under appropriate tariffs.

4.1.30 Transmission Reliability Margin (TRM)

The amount of Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

4.1.31 TRM multipliers (a & b)

“a”-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Planning Horizon

“b”-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Operating Horizon

4.2 CONCEPTS

4.2.1 Transfer Capability

Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission circuits (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). Transfer capability is also directional in nature. That is, the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

Some major points concerning transfer capability analysis are briefly outlined below:

1. **System Conditions** - Base system conditions are identified and modeled for the period being analyzed, including projected customer demand, generation dispatch, system configuration and base reserved and scheduled transfers.

2. **Critical Contingencies** - During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

3. **System Limits** - The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

Thermal and voltage transfer limits can be determined by calculating the First Contingency Incremental Transfer Capability. Stability studies may be performed by the Transmission Owners at their discretion. Any known stability limits, which are determined on a simultaneous basis, and all contractual limits will be supplied by each Transmission Owner in writing to the Transmission Provider and the TWG.

4.2.2 Available Transfer Capability

NERC Available Transfer Capability Definitions and Determinations, reference document (June 1996) states: “Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.”

SPP determines ATC as a function of the most limiting Flowgate of the path of interest. How limiting a Flowgate is to a path is based on two aspects: (1) The determined firm or non-firm Available Flowgate Capacity (FAFC or NFAFC) for that Flowgate, and (2) the TDF for which that Flowgate responds to power movement on the path under evaluation.

The common relationship between the identified limiting Flowgate and the path is the Transfer Distribution Factor (TDF). This is mathematically expressed as follows:

Firm ATC = the firm Available Flowgate Capacity divided by the Transmission Distribution Factor
(FATC = FAFC/TDF)
of the associated path.

Likewise,

Non-Firm ATC = the non firm Available Flowgate Capacity divided by the Transmission Distribution Factor
(NFATC = NFAFC/TDF)
of the associated path.

Path ATC is determined by identifying the most limiting Flowgates to the path in question. Each Flowgate represents a potential limiting element to any path within a system. Therefore, each Flowgate with known Transfer Distribution Factor (TDF) can be translated into path ATC. However, the Flowgate that produces the most limiting path ATC is the key Flowgate for that path.

The calculation of path ATC using this method is based on the ratio of the TDF into the remaining capacity of a Flowgate, (non firm Available Flowgate Capacity or firm Available Flowgate Capacity). Once a group of potential limiting elements has been selected, then all values pertaining to ATC can be translated based on the TDF.

4.2.3 Response Factors

Response Factors are numerical relationships between key adjustments in the transmission system and specific transmission components being monitored. They provide a linear means of extrapolation to an anticipated end for which decisions can be made. The thresholds for several of the following response factors are listed in Appendix 9.

(1) **Transfer Distribution Factor** - The Transfer Distribution Factor (TDF) is a general term referring to either PTDF or OTDF. The relationship between adjustments in participation points associated with a specific path and the identified Flowgate in the system is the TDF. Depending on the Flowgate type, the TDF may specifically represent the response in the system to certain types of pre-identified system limitations as mentioned in the System Limitations section of the criteria.

(2) **Line Outage Distribution Factor** - The Line Outage Distribution Factor (LODF) is the percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

(3) **Power Transfer Distribution Factor** - The Power Transfer Distribution Factor (PTDF) is the percentage of a power transfer that flows through a facility or a set of facilities for a particular transfer when there are no contingencies. PTDF type Flowgates are used for representing Thermal, Voltage, Stability and Contractual Limitations. To be considered a valid limit to transfers, a PTDF Flowgate must have a PTDF at or above the applicable short-term or long-term threshold.

(4) **Outage Transfer Distribution Factor** - The Outage Transfer Distribution Factor (OTDF) is the percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service. OTDF type Flowgates typically represent contingency based thermal limitations within the system. They can also be used to represent Stability limitations. To be considered a valid limit to transfers, a Monitored Facility must have an OTDF at or above the applicable short-term or long-term threshold.

(5) **Power Transfer Voltage Factor** - The Power Transfer Voltage Factor (PTVF) is the per unit amount that a facility's voltage changes due to a particular transfer level. To be considered a valid limit to transfers, a

Monitored Facility must have a PTVF at or above the applicable short-term or long-term threshold.

4.2.4 Transfer Capability Limitations

The electrical ability of the interconnected transmission network to reliably transfer electric power may be limited by any one or more of the following:

1. **Thermal Limits** - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission circuit ratings are defined in the SPP Rating of Equipment.

2. **Voltage Limits** - System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions of or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent. The Normal Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis. The Emergency Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance. Voltage limits will be as specified in the Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

3. **Stability Limits** - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a

disturbance. Specific Stability Limits Criteria is found in the SPP Criteria: Regional Transmission Coordinated Planning.

4. **Contractual Requirements**- Some Transmission Owners have contractual arrangements that contain mutual agreements regarding the power transfer available between them. These contractual arrangements have been approved by the appropriate regulatory agencies. The NERC Operating Policies inherently recognize contract requirements that may limit the power transfer between Transmission Owners. Some contract requirements are discussed in NERC Operating Policy 3 – Interchange.

The limiting conditions on some portions of the transmission network can shift among thermal, voltage, stability and contractual limits as the network operating conditions change over time

4.2.5 Invalid Limits

The procedures outlined in criteria may lead to identification of certain limiting facilities that are invalid. Reasons may include, but are not limited to:

- An invalid contingency generated as a generic single outage, which is not valid without the outage of other facilities.
- Incorrect ratings. Ratings will be corrected and the limiting transfer level recalculated.
- The rating used may be directional in nature (directional relaying) and may not be valid for the direction of flow.
- The limiting facility is the result of over-generation/under-generation at a participation point.
- The contingency is considered improper implementation of an operating procedure.
- The facility represents an equivalent circuit.
- The limiting facility is declared a Local Area Problem.

Any limiting facility determined to be invalid due to modeling error that could be corrected must be corrected by the next series of seasonal calculations.

4.2.6 Flowgates

Flowgates are selected power transmission element groups that act as proxies for the power transmission system capable of representing potential thermal, voltage, stability and contractual system limits to power transfer. There are two types of Flowgates;

- OTDF Flowgate; Composed of usually two power transmission elements in which the loss of one (contingency facility) can cause the other power transmission element (monitored facility) to reach its emergency rating.
- PTDF Flowgate; Composed of one or more power transmission elements in which the total pre-contingency flow over the flowgate cannot exceed a predetermined limit. Either with the power transmission system intact or with a contingency elsewhere, the Flowgate can be selected to represent a thermal, voltage, stability or contractual limit.

Once a set of limiting elements have been identified, as potential transfer constraints, they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the Total Flowgate Capacity (TFC) of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce.

To the extent that the impedance network models are similar with similar participation patterns, the same Flowgates can be monitored in other network models for purposes of evaluating the impact of additional transactions on the network. Of course, each network model will be subtly different therefore it is important that engineering judgment is exercised regarding the validity of applying existing Flowgates to a new network model.

4.2.7 Total Flowgate Capacity (TFC)

The Flowgate and its Total Flowgate Capacity are pre-defined. A Flowgate is intended to limit the amount of power allowed to flow over a defined element set. This TFC may reflect several possible types of system limitations as described in the Limitations Section.

For OTDF Flowgates representing thermal overloads, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility.

For PTDF Flowgates, the TFC represents the total amount of power that can flow over a defined element set under pre-contingency conditions.

Again, limit types could be:

1) Thermal limits under normal operating conditions or linked contingency events,
2) Voltage limits under normal operating conditions or linked contingency events,
3) Stability limits under normal operating conditions or linked contingency events, or
4) Contractual limits.

Flowgates are selected based on the impacts of power transfer in an electrical network and will be evaluated on a regular basis and revised as needed to ensure thorough representation of the system they are representing.

Each Flowgate represents a possible limitation within a network and in itself has a Flowgate rating (TFC) and an Available Flowgate Capacity (AFC) which can be translated via the path response factor (TDF) to a path Available Transfer Capability (path ATC) for any path.

4.2.8 Flowgate Capacity

4.2.8.1 Total Flowgate Capacity (TFC)

A Flowgate acts as proxy to path transfer limitations. This allows additional transfer capability on a path based on the additional loading that can be incurred. The determination of additional loading that can be incurred on a Flowgate begins first with the determination of the maximum loading that can be allowed on a PTDF Flowgate or on the monitored facility of an OTDF Flowgate during its associated contingency. This maximum loading is termed Total Flowgate Capacity (TFC).

4.2.8.2 Available Flowgate Capacity (AFC)

The available capacity on a Flowgate for additional loading for new power transfers is determined by taking the Total Flowgate Capacity (TFC) and removing the Flowgate

Base Loading (FBL) and the Impacts due to existing system commitments and any transmission margins.

AFC = TFC – FBL – Impacts of existing commitments – transmission margins

4.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC)

Path ATC is classified as firm or non-firm. This distinction is made when determining the Available Flowgate Capacity (AFC) remaining for path ATC. AFC is classified as firm or non-firm depending on the types of existing commitments considered for Impacts. This is realized in the formula for Available Flowgate Capacity:

(AFC = TFC – FBL – Impacts of existing commitments – transmission margins).

4.2.9 System Impacts

4.2.9.1 Impacts of Existing Commitments

In order to simultaneously account for impacts of all commitments to all paths at any given instant in time, it is necessary to devise a system that allows for fluctuation in the number of and the magnitude of system commitments on each path within an acceptable amount of time, for the purpose of providing transmission service in a competitive manner.

Existing transmission commitments beyond those modeled as native load and related generation commitments can be found on the OASIS. However, before impacts of OASIS posted reservations can be calculated, they must first be interpreted – carefully examined for peculiar individual characteristics. Due to the nature of the OASIS and the rules therein, posted reservations sometimes require interpretation as to their actual value to apply toward the transmission network.

The following are examples of evaluations that are performed:

- Recognize and adjust for duplicate reservations by multiple providers to complete one transaction.
- Adjust for reservations that may have changed status or have been replaced by another reservation, including renewals and redirects.
- Check for proper reflection of capacity profiles of reservations.
- Distinguish status and class of reservations such as Study, Accepted, Confirmed, Firm, and Non-Firm status to determine their proper impact level.

4.2.9.2 Positive Impacts

The scope of “Impacts of existing commitments” in the formula for AFC incorporates both the calculated positive impacts and counter impacts of non-firm and firm service commitments. A positive impact is determined as having the effect of increasing the loading on a Flowgate in the direction of the Flowgate. Positive impact types are sorted into those resulting from firm and non-firm service commitments. To determine firm or non-firm Available Flowgate Capacity, the appropriate impacts are applied to make up the “Impacts of existing commitments” in the above formula. Additionally, counter impacts are considered depending on firm or non-firm determinations.

4.2.9.3 Counter Impacts

Counter impacts are those impacts due to transfers that act to relieve loading on limiting elements. Counter impact types are sorted into those resulting from firm and non-firm service commitments. These flows are not traditionally accepted as valid under the pretense that any reservation that may cause such a loading relief is not actually doing so until it has been scheduled. To consider counter-flows in transfer capability studies is to assume a high probability of scheduling.

4.2.10 Monitored Facilities

During the Flowgate determination process those facilities monitored for pre-defined limiting conditions. Mandatory Monitored Facilities, for use in these calculations, are all facilities operated at 100 kV and above and all interconnections between Transmission Providers. Other facilities operated at lower voltage levels may be added to the Monitored Facilities list at the discretion of the Transmission Providers or Transmission Owners.

In defining Flowgates, the Monitored Facilities are those components of a Flowgate that remain in service following the defined contingency.

4.2.11 Critical Contingencies

Those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multi-terminal lines, or generating units. All interconnections of an area will be considered Critical Contingencies, regardless of voltage level as will the largest generating unit in the area.

4.3 RELIABILITY MARGINS

Transmission margins are very important to the reliability of the interconnected network in an Open Access environment. The NERC "Available Transfer Capability Definitions and Determination Reference Document" defines Transmission Reliability and Capacity Benefit margins (TRM, CBM).

When using Flowgates as a means to represent a system's constraints, it is necessary to translate reliability margins, TRM and CBM, to a unique TRM and CBM for each Flowgate. Margins are the required capacities that must be preserved for the purpose of moving power between areas during specific emergency conditions. Since a margin is a preservation of transfer capacity, the margin itself will have an impact on the most limiting element between the two areas for which it is reserved.

All studies for the purpose of assessing TRM and CBM will only include generation units located within the transmission system for which the Transmission Provider is responsible. These generation units may also include those not specifically designated to serve network load connected to transmission systems within the Transmission Provider system. However, the method by which a Transmission Provider is to determine TRM and CBM shall not vary from that described herein with the exception of assessing facilities located outside of SPP regional structure/bounds.

4.3.1 Transmission Reliability Margin (TRM)

TRM on a Flowgate basis is that amount of reserved Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The following factors shall be considered by SPP in the determination of TRM.

- Load Forecast

Transmission Providers will forecast hourly load for the next seven days for all applicable control areas.

Beyond seven days, Transmission Providers will project a demand based on seasonal peak load models for all applicable Transmission Owners. These load levels will be the projected peaks for the time frame for which the forecast applies.

- Variations in Generation Dispatch

Variations to generation patterns constitute a viable concern. Generation dispatch in near-term models will be based on real-time snapshots of network system conditions. For the longer-term horizons, whenever possible, generation dispatch information provided by generation owners will be applied to the ATC calculations. However, it is recognized that longer-term dispatch is probably unknown to the generation controlling entities themselves except for base-load and must run type units.

- Unaccounted Parallel Flows

Parallel flows can be an issue if pertinent data to the ATC calculations are not shared among the transmission providers and those transactions that have multiple wheeling parties are not identified. Provisions in the SPP OATT have reduced the impacts of these transactions within SPP and between SPP and other regions.

Transmission Owners of facilities that are impacted by unaccounted parallel flows or variations in dispatch may request additional TRM for their impacted Flowgates from the TWG. Such requests must be in writing, must document the parallel flow impacts or the variance in historical dispatch, and be accompanied by analysis or documentation supporting the additional TRM requirements. The

TWG shall have the authority to grant or reject requests for the additional TRM requests.

- SPP Operating Reserve Sharing

The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. To that end, TRM on the Flowgates will provide enough capacity to withstand the impact of the most critical generation loss to that facility. All generation contingencies will be simulated by the Operating Reserve Sharing algorithm to determine the highest impact on each Flowgate. This capacity will be included in TRM.

- Counter Flow Impacts

Another factor to consider in the SPP TRM process is that for the planning horizon, which is primarily next day and beyond, the counter flow impacts of reservations on the Flowgates are removed with the exception of Designated Network Resources. This provides an inherent margin in the calculation which along with the constant TRM provided by the reserve sharing allocation, is a proxy for the generation variation.

4.3.2 TRM Coordination

The TRM specified on a Flowgate represents a transmission margin that the transmission system needs to maintain a secure network under a reasonable range of uncertainties in system conditions. As such it is not necessarily an import or export quantity specifically. The Automatic Operating Reserve Sharing portion is determined by centralized Regional study based on the SPP Operating Reserve Sharing Criteria. Any additional TRM may be requested by the Flowgate owner/s, subject to review by the SPP TWG.

4.3.3 TRM Availability for Non-firm Service

To maximize transmission use to the extent reliably possible, Transmission Providers may sell TRM on a non-firm basis. The ‘a’ and ‘b’ multipliers facilitate this purpose in the calculations. However, a contingency or long-term outage to a high impact unit may result in the curtailment of non-firm schedules and displacement of non-firm reservations sold within the TRM.

4.3.4 TRM Calculation Frequency

The Operating Reserve Sharing portion of the TRM will be determined annually for each season (Spring, Summer, Fall, Winter). This process is outlined in the SPP Criteria under Operating Reserves and the Operating Reserve Share Program Procedures. Flowgate owner requests for additional TRM may be submitted at any time for consideration at the next TWG meeting. The submittal should include justification and rational in writing for the requested additional TRM. The TWG shall have authority to reject or grant such requests.

4.3.5 Capacity Benefit Margin (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin. As a normal practice, default values for CBM will be zero for calculations of ATC for some or all of the following reasons:

- the existing level of internal capacity margin of each member is adequate
- historical reliability indicators of transmission strength of the SPP area

- Open Access transmission usage environment allows greater purchasing options

Flowgate owner requests for additional CBM may be submitted at any time for consideration at the next TWG meeting. The submittal should include written justification and rational for the requested additional CBM. The TWG shall have authority to reject or grant such requests.

4.4 FLOWGATE AND TFC DETERMINATION

The Flowgates used by SPP to administer the Regional Tariff serve as a proxy of the transmission system. It is therefore essential to the reliable operation of the transmission system for the set of Flowgates to adequately represent the transmission system.

4.4.1 Flowgate Updates

Updating the list of Flowgates is a continual process. Flowgate additions and deletions and changes in TFC are the result of studies, analyses, and operating experience of SPP and its member Transmission Owners. At any time during the year, the owner of transmission facilities may require that a set of facilities be used as a Flowgate to protect equipment or maintain system reliability, regardless of the ownership of that set of facilities. SPP will update the Flowgate list as needed. The responsibility for reviewing and monitoring the list will be shared between the individual Transmission Owners, the TWG, the Operating Reliability Working Group (ORWG) and the SPP staff. Updating the Flowgate list may or may not require running a study. If the Transmission Owner is to perform a study, they are responsible for gathering accurate information from neighboring Transmission Owners. The following requirements apply when adding a Flowgate to the list:

- Transmission Owners may add OTDF Flowgates, provided that the contingency is valid, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility, and no operating procedures apply to that Flowgate.

- Transmission Owners may add PTDF Flowgates, provided that it is a single facility Flowgate, the TFC is equal to the normal rating of the single facility, and no operating procedures apply to that Flowgate.

- All other Flowgates proposed by Transmission Owners must have TWG and ORWG approval. The Reliability Authority can provide interim approval until the TWG and ORWG can convene to assess the request. Examples of such Flowgates are PTDF Flowgates with two or more elements, OTDF Flowgates with three or more elements, or Flowgates involving operating procedures.

There may be times when significant topological changes occur during operations that create unexpected loadings on facilities not explicitly modeled as Flowgates. During these conditions, the Reliability Coordinator will work with the Transmission Owner(s) to develop a commercial Flowgate representative of the conditions present. Any such additions will be analyzed at the next Flowgate evaluation to determine if they should remain in the permanent list of Flowgates.

4.4.2 Annual Review

In addition to the continual studies and analyses, the Flowgate list will also be reviewed annually by the TWG using seasonal power flow models. This annual assessment will be performed following the January SPP Model Development Work Group (MDWG) release of each year's load flow cases. This review is intended to serve as a tool by which the TWG, the Transmission Owners, and the SPP may assess the adequacy of the existing list of Flowgates and thereby recommend necessary additions, deletions, and TFC changes. In order to accomplish this assessment, the process herein described will be used to identify the most limiting elements for a variety of transfer directions. Although transfer values will be involved in this process, this process is not intended to produce any viable ATC values for use commercially or otherwise. Rather, ATC values are determined as described in the "ATC Calculation Procedures" section.

4.4.2.1 Power Flow Models

The power flow models to be used in the process will be based on the models developed annually by the SPP MDWG. Application of the models will use the following season definitions. The Summer Model will apply to June through September, the Fall Model will apply to October and November, the Winter Model will apply to December through

March and the Spring Model will apply to April and May. Each of these seasonal models developed will represent peak models. In addition, for the summer season only, a Summer Shoulder Case representing approximately an 85% load level will be used in the determination process.

Prior to the start of the review all SPP Transmission Owners will submit a list of changes to SPP to adjust the models. These changes should be such that the power flow models used to review the Flowgate list represent the seasonal loads, transmission system configuration, generation dispatch, and transactions that each Transmission Owner expects will occur during actual seasonal operations. The changes will be submitted to SPP in a common format as outlined in the SPP Load Flow Procedure Manual.

Model changes and parameters for Transmission Owners outside of SPP will be coordinated through the NERC regional councils.

4.4.2.2 Parameters supplied by the Transmission Owners

In order to simulate a transfer, certain parameters must be known. These include the participation points of MW increase/decrease and the participation factor of these points. These items will be supplied to SPP by the Transmission Owners.

Participation points for exports will primarily be points of generation within the sending area. Generators that are off-line may be turned on to participate in a transfer. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The participation points used for export will be consistent for all transfer directions.

The participation points for imports will primarily be points of generation reduction within the receiving area. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The generation reduction should be based on economics, operating constraints or other criteria as specified by the Transmission Owner. The participation points used for import will be consistent for all transfer directions.

Other parameters that must be supplied by the Transmission Owners include the following:

- A contingency list including all critical single contingencies (both transmission and generation) as well as multi-terminal facilities.
- All contingencies suspect of causing voltage limitations and the transfers for which they should be studied.
- Any additional facilities below 100 kV to be monitored.
- High and low voltage limits for system and/or individual buses.
- All Contractual Requirements.

4.4.2.3 Default Parameters

The following parameters will be used in the event that a Transmission Owner does not submit the area specific parameters:

- For exports, the participation points will include all on-line generating facilities in the model with unused generating capacity available.
- The export participation factors will be the amount of unused generating capacity at each point divided by the sum of the unused generating capacity at all export participation points. (i.e., PMAX-PGEN).
- For imports, all on-line generators will be decreased prorated by their capable generation (i.e., PGEN-PMIN).
- Transfer directions will be a set of all commercial paths.
- Exports from merchant power plants will be considered in the determination of Flowgates.
- The transfer test levels are specified at the time of the ATC calculations, and are determined by SPP staff.
- All facilities 100 kV and above will be included in the contingency list and the monitored facility list. In addition, the largest unit within the area will be included in the contingency list.
- Voltage limits will be as specified in Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

4.4.2.4 Voltage Limits

Voltage limits are network and system dependent. Each Transmission Owner will submit an acceptable set of Normal Voltage Limits and Emergency Voltage Limits to be applied for the purpose of Flowgate and TFC determination.

4.4.2.5 Linear Analysis and AC Verification

SPP will perform DC linear analysis studies estimating the import or export ability of the identified commercial paths using a combined linear evaluation of the network models with a follow up AC verification of a minimum of the first three valid operational limitations. Specific AC analysis will also be performed on any specified contingency/transfer combinations noted as voltage limiting contingencies. Monitored Facilities, Contingency Facilities and Participation Points will be implemented as described in the “Parameters Supplied by the Transmission Owners” section or “Default Parameters” section as applicable.

4.4.2.6 Operating Procedures

Operating Procedures are available and may increase the Total Flowgate Capacity of a Flowgate when implemented. Implementation of any available Operating Procedures will be done using a full AC solution to determine the correct limit to be placed on a Flowgate. Any operationally increased Total Flowgate Capacities established will be so noted.

4.4.2.7 Identification of Flowgate Changes

TWG will review the FCITC results of the power flow models and selected paths and identify whether any Flowgates should be added, removed, or changed to better represent the SPP transmission system.

A minimum of the first three valid FCITC limitations to each path will be AC verified. When all paths have been evaluated, the TWG will review the AC verification results and, where needed, the linear results for consideration as potential Flowgates.

Typically, new Flowgates should be either OTDF Flowgates with a TFC representing the total amount of power that can flow during a contingency without violating the emergency rating of the monitored facility or single facility PTDF Flowgates with a TFC equal to the normal rating of the single facility. In situations involving operating procedures the TFC may be higher than the facility ratings.

The TWG will then determine any needed changes to the existing list of Flowgates. The number of times elements appear as one of the most limiting components for transfers, the rank in the list of most limiting elements, and the TDF level will be the primary factors considered in making the determination. Flowgates can also be developed to represent identified Voltage Limitations and Contractual Requirements.

4.4.2.8 Review and Coordination with Transmission Owners

Each SPP Transmission Owner will have the option of naming a representative to review the results of the Flowgate review or deferring to the TWG finalization of the results. Summary sheets of all interfaces or paths calculated will be communicated to the representatives for review. All data will be made available for review upon request. The results will be approved by the TWG before being reported.

The Transmission Owner should review the TWG proposed Flowgate changes and consider their own operating experience and study results. Any modifications to the TWG proposed changes should be returned to the TWG. Further dialog and justification may be required of a Transmission Owner if the TWG has concerns about their modifications.

TWG will draft a final Flowgate list, incorporating the comments of the Transmission Owners. The Transmission Owners should approve any additions, deletions, or changes to the Flowgate list.

4.4.2.9 Initiating Interim Review of Flowgate List

Operational condition changes, especially status changes of EHV transmission facilities and large generators, may warrant a partial or full evaluation of the list of Flowgates. A review may also be necessary due to multiple schedules being implemented causing parallel flows.

Transmission Owners will have access to copies of the SPP models and all relevant data used for the annual review. Transmission Owners may at any time request a re-run of the Flowgate evaluations. The Transmission Owner requesting the re-run shall provide their reasons for requesting the re-run to the TWG for consideration. Should the TWG deem a re-run necessary, the SPP staff will perform the additional evaluation.

4.4.3 Dispute Resolution

If there is a dispute concerning a Flowgate, the questioning party must contact SPP and the Transmission Owner(s) involved to resolve the dispute.

Examples of reasons for disputing a Flowgate may include:

- The contingency used for the Flowgate is not valid.
- There is an operating procedure that corrects the violation that is not being properly taken into account.
- An operating procedure is being taken into account in an improper manner yielding an incorrect TFC.

If the parties involved do not reach agreement on the selected Flowgates, the SPP TWG will review all of the arguments. Additional analyses will be performed if necessary. SPP TWG will then make a final determination. If a party still wishes to dispute the Flowgate, the SPP Dispute Resolution policy described in Section 2 of the SPP By-laws may be initiated.

4.4.4 Coordination with Non-SPP Members

Flowgates involving transfers on interfaces and paths between SPP Transmission Owners and non-SPP Transmission Owners will be coordinated by the parties involved and the TWG.

4.4.5 Feedback to SPP Members

The SPP staff shall maintain a table of all Flowgates on the SPP OASIS. The table shall include all Flowgate data, which are applicable, including the Flowgate name, monitored facility, contingency facility, Flowgate rating, TRM, CBM, a and b multipliers, LODF, the TDF basis for the Flowgate (OTDF or PTDF), and the TDF cutoff threshold. This table shall be updated with any new information on or before the first of each month.

4.5 ATC CALCULATION PROCEDURES

The determination of ATC via Flowgates utilizes proxy elements to represent the power transmission network. This process depends on the selected Flowgates to act as pre-determined limiting constraints to power transfer. The process by which ATC will be determined when using the Flowgate proxy technique incorporates the Definitions and Concepts within this Criteria.

Determination of ATC via Flowgates adheres to the following approach:

- establishes a network representation (power flow model)
- identifies potential limits to transfer (thermal, voltage, stability, contract)
- determines response factors of identified limits relative to transfer directions (TDF)
- determines impacts of existing commitments (firm, non-firm)
- applies margins (TRM, CBM, a & b multipliers)
- determines maximum transfer capabilities allowed by limits and applied margins (ATC, FATC, NFATC)

4.5.1 ATC Calculation and Posting Timeframes

To assist Transmission Providers with Short Term service obligations under FERC Order 888 and 889, SPP will calculate the monthly path ATC for the upcoming 16-months for all potential commercial paths for Transmission Providers in the SPP Region. This data will be posted for use in evaluating the SPP OATT requests and provided on a monthly basis to the Transmission Providers in adequate time to post the information on OASIS nodes by the 1st of each month.

Hourly, Daily and Weekly ATC shall be calculated on a daily basis and posted at the time of run. SPP will also provide commercial path conversions to any individual providers needing that information to administer their own tariff. Hourly ATC shall be calculated for 12 to 36 hours ahead depending on time of day. SPP has a firm scheduling deadline at 12:00 noon of the day prior to start. At this point all firm schedules are known and the hourly non-firm request window opens for the next day. At this point SPP will calculate hourly ATC for HE 14 of the current day through HE 24 of the next day. This process continues dropping the current hour each resynchronization until 12:00 noon the next day when the cycle starts again. Again SPP will provide commercial path conversions for any SPP provider that needs them for posting on their own OASIS nodes.

4.5.2 Power Flow Models

The monthly calculation of Flowgate based ATC will be made using rolling seasonal models that produce an update for the upcoming sixteen month service window (12 month multi-month service + 4 months advance notice). For example, the required data update for January of any year will yield data for January thru December plus the next January, February, March and April of the following year. The necessary seasonal models will be selected from the approved SPP MDWG set to represent this time frame. Any known system changes/corrections to these models will be included. SPP will routinely calculate ATC for the upcoming 16-month service window. Monthly models will be updated/developed from the latest seasonal models to represent individual months for the purpose of capturing operational conditions that may be unique from other monthly models.

4.5.3 Base Loading, Firm and Non-Firm (FBL & NFBL)

Model base flows provide the basis for which to begin determination of Available Flowgate Capacity. However, there are many transactions within the monthly models that are duplicated on the OASIS. A record of the network model flows of each Flowgate as found in the solved network models will be used as a beginning point to account for impacts of base case transactions and existing commitments. The impacts on Flowgates due to transactions outside the purpose of representing designated Network Resource exchange will be removed by applying the TDF factors determined to each transaction identified in the base case. In addition to adjusting the model flow in this manner, positive and counter impacts of existing OASIS commitments will be applied according to the type of Base Loading (Firm or Non-Firm) under consideration. In non-firm Base Loading, 50% of Counter Impacts resulting from firm Confirmed reservations will act to reduce the overall Base Loading figure. This process will establish the base loading expected with each control area serving its firm Network Load.

4.5.4 Transfer Distribution Factor Determinations (TDF)

For export and import participation points all on-line generators, unless otherwise denoted (e.g., nuclear units), will be scaled prorated by their machine base (MBASE). TDF data will be calculated for all commercial paths using the most current participation data, ATC models and Flowgate list on a monthly basis.

4.5.5 Existing Commitments and Netting Practices

Existing commitments resulting from Confirmed, Accepted and Study reservations on the SPP OATT OASIS nodes will be considered and accounted for in the determination of Available Flowgate Capacity. Accounting for the impact of existing commitments is a key part of the process for determining which new transfers will be allowed, unlike the TLR implementation process which involves determining which existing transfers must be curtailed. Therefore, unlike TLR implementation which requires a minimum TDF threshold, all positive impacts from existing commitments must be applied without using a minimum TDF threshold. Impacts from these commitments will be applied according to the future time frame of which they are applicable. These time frames are discussed below:

4.5.5.1 Yearly Calculations (whole years, starting 60 days out)

A Yearly transmission service request is defined as a service request with a duration of greater than or equal to 1 year in length. The evaluation of Available Transfer Capability for this service type is performed utilizing solved network models with existing OASIS commitments figured in as net area interchange values. In addition to monitoring Flowgates, standard N-1 contingency analyses will be performed to study the impact of yearly transmission requests on the transmission system. The long-term threshold is shown in Appendix 9 and is applied to all elements above 60kV.

4.5.5.2 Monthly Calculations (months 2 through 16)

The impacts of OASIS reservations that are Confirmed, Accepted and in Study mode will be applied to each Flowgate according to the TDF values determined. All positive impacts on a Flowgate due to these types of reservations decrease ATC. 100% of counter flow impacts due to reservations supplying Designated Network Resources are allowed to increase ATC. For non-firm service, up to 50% of the counter-flows due to all firm Confirmed reservations will be allowed on a Flowgate. The combined positive impacts and counter flow impacts will be added to the base flows to determine Available Flowgate Capacity for the Monthly calculation.

4.5.5.3 Daily and Weekly Calculations (Day 2 through 31)

For Daily and Weekly calculations, composite area interchange values will be determined by integrating all OASIS Confirmed and Accepted reservations into projection models. Base flows will be determined by the projection models. The impacts of OASIS reservations that are in Study mode will be applied to each Flowgate according to the TDF values determined. Positive impacts on a Flowgate due to Confirmed reservations that are not expected to be scheduled based on actual historical scheduling data will be removed and allowed to increase firm Available Flowgate Capacity. Counter flow impacts of Confirmed reservations that are expected to be scheduled based on actual historical scheduling data will be allowed to increase firm Available Flowgate Capacity. Up to 50% of the counter flow impacts due to all firm Confirmed reservations will be allowed to increase non-firm Available Flowgate Capacity.

4.5.5.4 Hourly Calculations (Day 1)

These calculations are for hourly non-firm service only. All known schedule information from NERC Electronic-tags will be applied to base flow calculations. These schedules determine base interchange values. Since these are expected schedules, all counter flow impacts are allowed in this calculation. OASIS reservation information is not considered for determination of existing impacts in this calculation.

4.5.6 Partial Path Reservations

Requests made on individual Transmission Provider's tariffs require two or more reservations to complete a transaction resulting in a partial path reservation. The SPP OATT offers service out of, into and across SPP and between SPP members with a single reservation. For transmission service under the SPP OATT, only reservations with valid sources and sinks are allowed. However, to avoid double accounting of Flowgate and system impacts due to duplicate reservations documented on Transmission Provider OATT OASIS nodes from partial path reservations, necessary means will be incorporated to recognize these related reservations and determine the correct singular impacts.

4.5.7 ATC Adjustments Between Calculations

ATC will be adjusted following receipt of any valid SPP OASIS node reservation. The requested capacity will be multiplied by the TDF on all affected Flowgates and the resulting amounts will be subtracted from each Flowgates' ATC and posted to the OASIS.

4.5.8 Coordination of Transmission Commitments with Neighboring Organizations

Coordination of dispatch information, Confirmed firm and non-firm system commitments from neighboring regions, RTO's, ISO's etc. will be conducted as appropriate to each type of ATC being determined to establish the most accurate system representation of base flows and generation profiles. External reservations may be retrieved from other OASIS sites or locations designated by neighboring Transmission Providers.

4.5.9 Margins

Identified TRM and CBM will be applied to each Flowgate as described in the Reliability Margins section.

4.5.10 ATC Determination

The following equations are used in ATC determination:

4.5.10.1 Firm Base Loading (FBL)*, **:

- Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm OASIS Commitments, Confirmed, Accepted and Study) – (100% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments for DNR only)

4.5.10.2 Non-Firm Base Loading (NFBL)*, **:

- Non-Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm and Non-Firm OASIS Commitments, Confirmed, Accepted and Study) – (up to 50% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments)

4.5.10.3 Firm Available Flowgate Capacity (FAFC):

- Firm Available Flowgate Capacity = (Total Flowgate Capacity) – (TRM) – (CBM) – (Firm Base Loading)

4.5.10.4 Non-Firm Available Flowgate Capacity (NFAFC, Operating Horizon):

- Non-Firm Available Flowgate Capacity, Operating Horizon = (Total Flowgate Capacity) – (b*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.5 Non-Firm Available Flowgate Capacity (NFAFC, Planning Horizon):

- Non-Firm Available Flowgate Capacity, Planning Horizon = (Total Flowgate Capacity) – (a*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.6 Firm Available Transfer Capability (FATC):

- Firm ATC = Most limiting value from associated Flowgates = Min {Firm Available Flowgate Capacity/TDF of appropriate path}

4.5.10.7 Non-Firm Path Available Transfer Capability (NATC, Operating Horizon):

- Non-Firm ATC, Operating Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Operating Horizon/TDF of appropriate path}

4.5.10.8 Non-Firm Available Transfer Capability (NFATC, Planning Horizon):

- Non-Firm ATC, Planning Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Planning Horizon/TDF of appropriate path}

* Applicable pre-emption requirements of lower priority service types will be considered when evaluating requests for transmission service.

** Impacts resulting from queued Study reservations will be applied according to priority when evaluating requests for transmission service.

SPP will calculate the ATC for each of its Transmission Providers on their direct interconnections (either physical interconnections or by rights to a line) and any interface or path requested by a Transmission Provider to fulfill its obligations under FERC Order 889. The ATC for requested interfaces or paths will be calculated only if requested by the Transmission Provider obligated to post the interfaces or paths.

4.5.11 Annual Review of ATC Process

The SPP TWG will conduct an annual review of the Regional ATC determination process including TRM and CBM to assess regional compliance with NERC requirements, regional reliability needs and functionality toward SPP Transmission Owners and Users. This review will be held at the same time as the Flowgate Evaluation process. The applicable long-term TRM is listed in Appendix 9.

SPP will conduct a survey of the Transmission Owners and Users and the results will be published on the SPP website. Concerns that are identified from the survey will be forwarded to the appropriate SPP Committee.

4.5.12 Dialog With Transmission Users

Transmission Users may contact the TWG with any concerns regarding this criterion, its implementation, or the resulting ATC values. The concerns should be in writing and sent to the chair of the TWG. The chair will then draft a written response to the Transmission User containing either an answer or a schedule for when such an answer can be provided. If the Transmission User is not satisfied, the concerns can be sent to the chair of the Markets and Operations Policy Committee.

Appendix 1

ISO NEW ENGLAND

ATC METHODOLOGY

Rev. February 2005

1. INTRODUCTION

The New England Control Area covers the six New England states: Vermont, New Hampshire, Maine, Massachusetts, Connecticut, and Rhode Island.
Within New England Control Area there are 12 Transmission Providers (TP) and one Merchant Transmission Facility (MTF). They are:

<u>TRANSMISSION PROVIDERS:</u>

- Bangor Hydro Electric Company (BHE)
- Central Maine Power Company (CMP)
- Central Vermont Public Service Company (CVPS)
- Citizen Utilities Company (CZN)
- Florida Power and Light (FPL)
- Green Mountain Power Company (GMP)
- Maine Electric Power Company (MEPCO)
- **ISO New England (ISNE)**

  - also known as the Pool Transmission Facilities (PTF)
- New England Power Company (NEP)/National Grid USA.
  - It includes former Eastern Utilities Association (Montaup) (EUA)
- Northeast Utilities System (NU)
- NSTAR:
  - Former Boston Edison Company (BECO)
  - Former Cambridge Electric Company (CELC)
  - Former Commonwealth Electric Company (COM)
- United Illuminating Company (UI)
- Unitil (UNITIL)
- Vermont Electric Company (VELCO)

<u>MERCHANT TRANSMISSION FACILITY:</u>

- Cross Sound Cable (CSC)

ISO New England (ISO) provides administration services for the ISO New England Transmission Provider (ISNE). This document describes the methodology used by ISO to calculate Total Transfer Capability (TTC) between the New England Control Area and neighboring Control Areas (New York, Quebec and New Brunswick). The document also describes the Available Transfer Capability (ATC) between ISNE and non-ISNE interfaces.

The other transmission providers and the transmission merchant facility listed above have their own methodologies.

TTC and ATC values for ISNE are posted on the ISO NEW ENGLAND OASIS under the ISNE Node. Transmission Services for the other transmission providers are also posted on the ISO NEW ENGLAND OASIS under their unique nodes.

2. OPEN ACCESS WITHIN ISO NEW ENGLAND

There are two types of Open Access for transmission services available in the New England Control Area: financial transmission under the Standard Market Design System (SMD) and the Physical transmission under the traditional Pro Forma Reservation System.

ISNE Services under SMD

The implementation of the Standard Market Design (SMD) on March 1st 2003 has changed the calculation, posting and use of ATC values on the ISNE Node.

Under SMD rules, there are no advanced transmission reservations required for external transactions over the ISNE facilities known as Pool Transmission Facilities (PTF). External energy is scheduled economically based on offers and bids within the SMD, and transmission service is automatically granted to those offers and bids that are scheduled to flow at the beginning of the scheduling hour.

Requests for external energy schedules are not restricted by the ATC value at the time of submittal. The posted ATC is simply calculated based on the MW amount of accepted offers and bids submitted to the market and serves as an indicator of the requested utilization of the external interfaces. Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM), parameters associated are not needed for the Market System and have zero MW value.

Under SMD the need to calculate both Firm and non-Firm ATC will no longer be required. Since transmission service will be granted as part of a transaction that actually flows, all service will have the same priority, therefore ATC will be representative of this.

Physical Based Transmission Service

The other Transmission Providers within New England will continue offering advanced reservations for Pro Forma transmission service under the traditional Physical Reservation System. Firm and non-Firm ATC will continue to be decremented by advance reservations and where appropriate TRM

3. ISO NEW ENGLAND INTERFACES

The following is a list of Transmission providers that offer service over the external Control Area Boundaries. With the exception of the New York free-flow ties and the Highgate tie, all other external control area interfaces required service from both the ISNE and another Transmission Provider.

Note: Appendices A, B, and C provide further detailed information of interfaces.

ISNE – Interfaces

- NE –New York (Free-Flow Ties),
- NE –MEPCO
- NE – Phase I/II (Comerford / Sandy Pond)
- NE – Highgate
- NE – Cross Sound Cable

(Note: Market Based Service, No physical reservations are needed)

MEPCO – Interfaces

- MEPCO – ISNE
- MEPCO – New Brunswick

(Note: Advance Physical Reservations required, administered by MEPCO)

Phase I/II – Interfaces

- Phase I/II – ISNE (Comerford / Sandy Pond)
- Phase I/II – Hydro Quebec

(Note: Phase I and II cannot operate simultaneously. Normal Operation is over Phase II facility. Advance Physical Reservations required, administered based on ownership share by NSTAR, CMP, CVPS, Citizens Utilities, GMP, NEP, NU and

UI)

Highgate – Interface

- ISNE– Hydro Quebec

Cross Sound Cable – Interfaces

- CSC – ISNE
- CSC – New York (Long Island) (Note: Advance Physical Reservations required, administered by CSC)

4. TOTAL TRANSFER CAPABILITY (TTC)

NERC Definition

The Total Transfer Capability (TTC) for an interface is the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame.

Basis For TTC

TTCs for ISO NEW ENGLAND interfaces are forecast by the ISO based on thermal, voltage, and/or stability limitations of the ties that comprise the interface. Power flow and transient stability analysis is used to ensure that physical limits will not be violated for credible system contingencies per NPCC and ISO NEW ENGLAND reliability criteria.

Future Forecasts

The TTC forecast for periods beyond 40 days out is based on seasonal operating studies that take into account anticipated peak loads and generator maintenance schedules.

Within 40 days, a base TTC is calculated from historical "all lines in" data that takes into account seasonal load distributions. The base TTC is adjusted daily into a forecast value that accounts for:

- Forecast loads
- Actual and scheduled transmission and generator outages in ISO NEW ENGLAND and neighboring systems
- Changes in facility ratings
- Anticipated loading of generators
- Anticipated inter-Area schedules or bids and offers for the Market System

Variations Across Interfaces

Factors used in calculating TTC for each of the ISO NEW ENGLAND interfaces vary.

ISO vs. Transmission Provider Responsibility

ISO will calculate and post TTC for ISNE and the external Control Area Interfaces.

Individual Transmission Providers will post TTC for their individual system.

(Note: ISO provides a service to the other Transmission Providers to fulfill this requirement and provide coordination between the interfaces within New England.)

ISNE Posted TTC Values (as posted by ISO-NE)

Hourly TTC

Hourly values are provided for the current day, plus the next 7 days, for each ISNE interface

Adjustments made to the base TTC values for posted interfaces can be seen in hour-byhour detail.

The Hourly TTC is the MINIMUM TTC for that Hour.

Daily TTC

Daily values for the current day plus the next 39 days for each ISNE interface.

The TTC values for the first 8 days in this group are adjusted for hourly maintenance and details can be viewed in the Hourly TTC section. Days 9 through 40 use historical database TTC values.

The Daily TTC is the MINIMUM Hourly TTC for the Day.

Weekly TTC

Weekly values are shown for the current week plus the next 12 weeks for each interface.

A week always starts at 0001 on a Monday and ends hour ending 24 on the following Sunday.

Note that the TTC values for the first 5 weeks (made up of the current week plus the next 5 weeks) will reflect adjustments made for known hourly or daily maintenance.

The Weekly TTC is the MAXIMUM Daily TTC for the 7-day week.

Monthly TTC

Monthly values cover the current month and the next 12 months for a total of 13 calendar months. Each interface has the **MAXIMUM** value posted which is based on the historical data.

If maintenance is scheduled for an entire month it will be reflected in the Monthly TTC. *The Monthly TTC is the MAXIMUM Daily TTC for the month.*

Yearly TTC

Yearly values reflect 2 years beyond the current year.

Yearly TTC is the MAXIMUM value between summer and winter Analysis for the year.

5. TRANSMISSION RELIABILITY MARGIN (TRM)

Definition

The Transmission Reliability Margin (TRM) is the portion of TTC that cannot be used for reservation of firm transmission service because of uncertainties in system operation. It is used only for interfaces under the physical reservation system.

Variability Of TRM

The TRMs are interface-dependent, direction specific and time-dependent.

ISO vs. Transmission Provider Methodology

For Market based ISNE services, there is no TRM and it has zero MW value

For Physical based services TRM will be dependant on forecasted system conditions and the interface.

TRM Values

INTERFACE	TRANSMISSION PROVIDER	TRM
NY-NE	ISNE	0 MW
PHASE II/I (NE-HQ)	Individual Owners	Posted by TPs
HIGHGATE (NE-HQ)	ISNE	0 MW
NB- NE	ISNE and MEPCO	Posted by MEPCO
CSC (NE-LI)	ISNE and CSC	TRM=346MW(both directions)

NOTE: Appendix D illustrates typical TRM and TTC values for the interfaces under the Physical Reservation System. The exact values are posted on the appropriate OASIS node

6. CAPACITY BENEFIT MARGIN (CBM)

Definition

The Capacity Benefit Margin (CBM) is the required MW amount of Total Transfer Capability to meet generation reliability requirements. CBM allows Load Serving entities to reduce its installed generating capacity. CBM is an importing quantity.

Capacity Benefit Margin Under SMD

The implementation of the Market System in the New England Control Area (May 1999) eliminated the need to hold transmission capability from the Market in the form of Capacity Benefit Margin (CBM). ISO New England uses zero MW of CBM when calculating Available Transfer Capabilities on its interconnection with other Control Areas.

Under the current Standard Market Design (SMD) implemented on March 1st 2003, Load Serving Entities (LSEs) operating in the New England Control Area are required to arrange their Installed Capability requirements (generation reliability requirements) prior to the beginning of any given month.

Since the present SMD accepts bids and offers only for 10 days ahead for a maximum duration of 30 days and there are no transmission reservations under SMD, CBM is zero MW and all LSEs in New England must meet generation requirements before actual dispatch occurs.

7. AVAILABLE TRANSFER CAPABILITY (ATC)

ATC For Market Based Services

SMD does not require physical reservations for transmission service on the PTF; therefore, the designation of Firm and Non-firm to ATC in regard to the PTF is no longer appropriate. There is only a single value for ATC

ATC is used as an indicator of utilization of the interfaces.

The market ATC will be calculated according to the following equations:

- Hourly ATC = TTC –Submitted Schedules (current day plus 7 days in advance)
- Daily ATC = TTC –Submitted Schedules (current day plus 39 days in advance)
- Weekly ATC = TTC –Excepted Transactions Reservations (current week plus 5 weeks in advance)
- Monthly ATC = TTC –Excepted Transactions Reservations (current month plus 12 months in advance)
- Long Term ATC = TTC –Excepted Transactions Reservations (up to 2 years in advance)

Negative ATC

Negative ATC in the market-based system can be an indication of increased demand for transactions flowing in a particular direction. Since ATC will not limit the amount of transactions to be considered for scheduling there could be times when ATC indicates a substantially negative value. It must be recognized that a negative ATC should not discourage the submittal of a transactions, as the economic evaluation of these schedules has not taken place. It is this economic evaluation that will assure that transfer limits are honored.

Definition Of Firm ATC For The Physical Reservation System (non-PTF and MTF Transmission Services)

Firm Available Transfer Capability (Firm ATC) for an interface is the capability for firm transmission reservations that remains after allowing for existing firm commitments and the TRM. Mathematically, Firm ATC is calculated using the equation:

FIRM ATC = TTC – TRM – CBM (for Imports) – Existing Firm Commitments *

* Existing Firm Commitments consist of, Firm transmission requests in the following status: Confirmed, Accepted and Study.

Definition Of Non-Firm ATC For The Physical Reservation System (non-PTF and MTF Transmission Services)

Non-firm Available Transfer Capability (Non-Firm ATC) for an interface is the capability for non-firm transmission reservations that remains after allowing for existing commitments in the Confirmed and Accepted status.

Mathematically, Non-Firm ATC is calculated using the equation:

- NON-FIRM ATC = TTC – Existing Firm & Non-Firm Commitments in the Confirmed and Accepted Status.

8. DETERMINATION AND POSTING OF TTC AND ATC

Location Of Posting

TTC and ATC values for all New England interfaces are posted on the ISO NEW ENGLAND OASIS web page (PTF, non-PTF and MTF). The values are accessed through the OASIS node by selecting the Transmission Provider's page (ISNE, MEPCO, CSC, etc.). Some interfaces are posted by more than one Transmission Provider, such as, Phase I/II where there is joint ownership.

Updates To TTC And ATC

TTC and ATC values are calculated and posted for each of the following time frames:

- Hourly
- Daily
- Weekly
- Monthly
- Yearly

Base TTC values for the longer term postings are determined using "all lines in" normal system configuration. Closer to real time, changes to the normal configuration as a result of scheduled maintenance or unscheduled outages are known and can result in more or less restrictive transfer limitations.

Short-term analysis may be performed to assess the effects of outages and other changes on base TTCs. Adjustments to the base TTC values are made to nearer term values as appropriate to reflect the changes in limitations.

Updates To TTC

The ISO evaluates all TTC values, with the exception of yearly values, for each interface a minimum of once per business day and whenever changes in system conditions warrant.

Updates To ATC

Market Based

The ISO has software applications that dynamically recalculate the single value ATC and update the OASIS posting as each transaction request with the ISO NEW ENGLAND RTG is received.

Physical Reservation Based

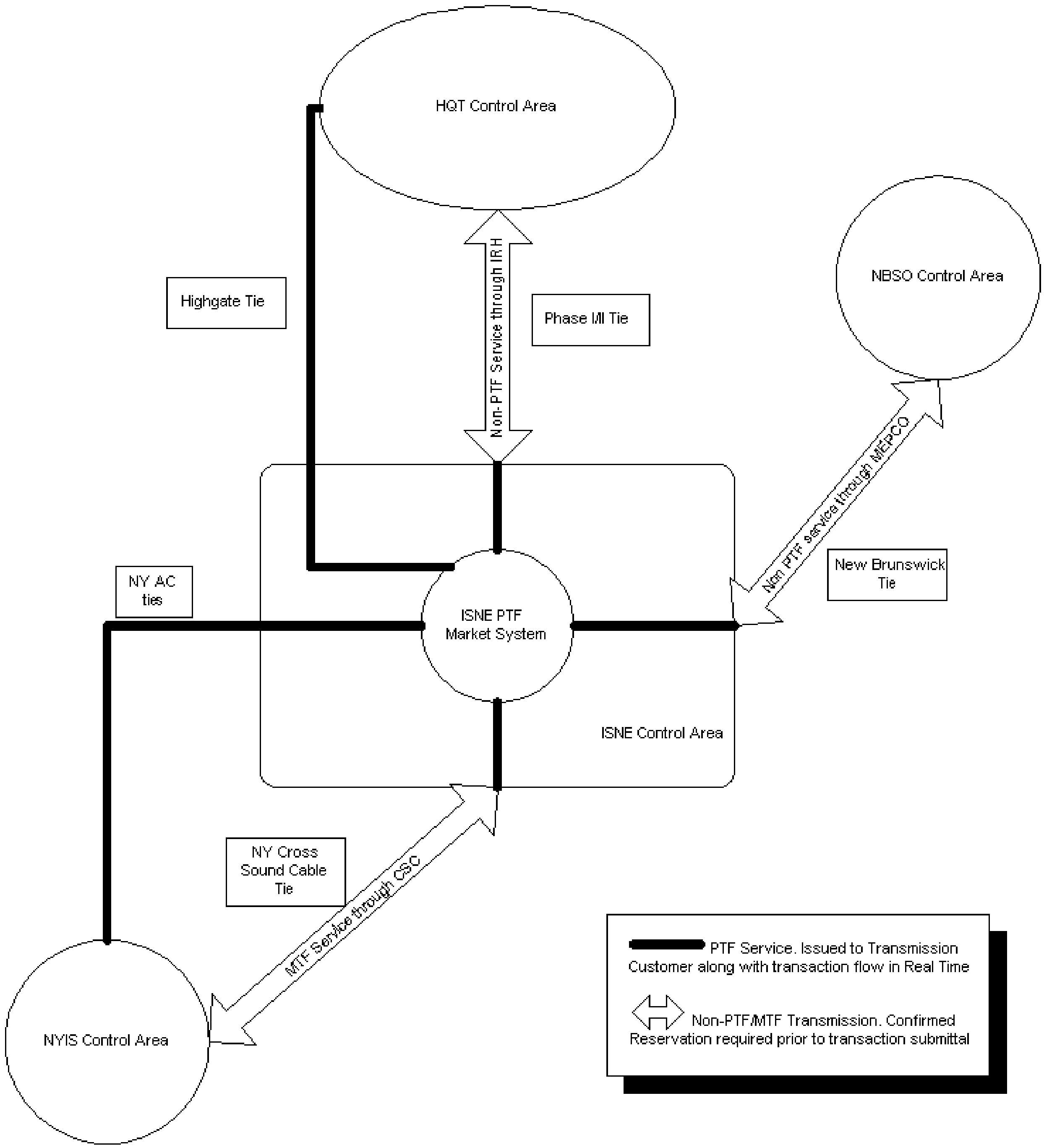
Individual Transmission Providers will calculate ATC and post both TTC and ATC for their individual system.

Firm ATC and Non-Firm ATC values for the interface posted by other transmission providers are calculated and updated based on reservations received by those transmission providers.

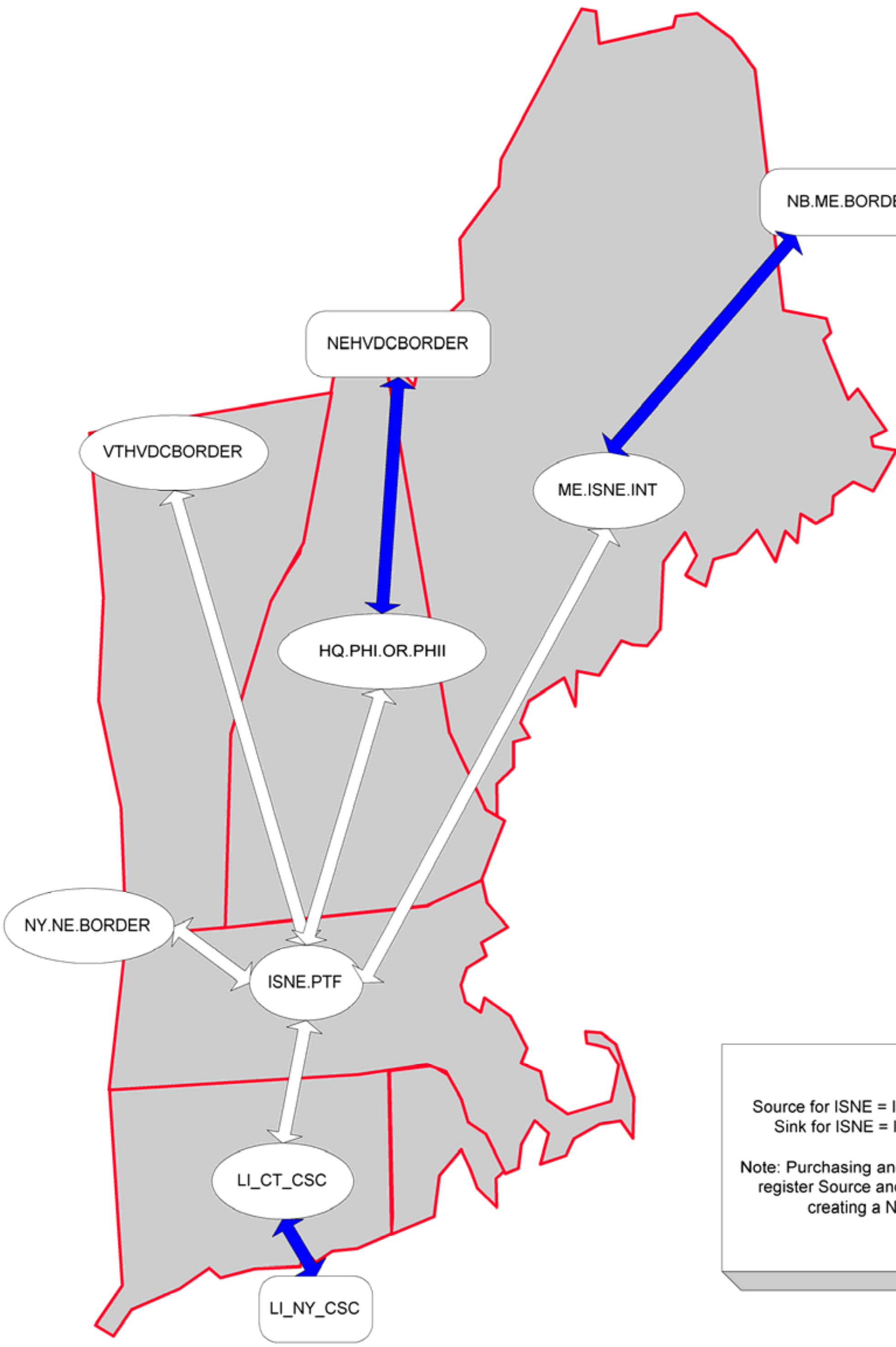
9. REFERENCES

- Transmission Transfer Capability. NERC, May 1995
- Available Transfer Capability Definitions and Determination. NERC June 1996
- NPCC Methodology and Guidelines for Forecasting TTC and ATC. NPCC. April 2001
- ISO NEW ENGLAND Open Access Transmission Tariff. Attachment C
- ISO NEW ENGLAND Operating Procedure 19 (OP19) Transmission Operations
- NPCC Document A2 Basic Criteria for Design and Operation of Interconnected Power Systems. January 2003

Appendix A: ISNE Control Area Reservation System



Appendix B:
POR and POD definitions within ISNE Control Area



Source for ISNE = ISNESYSPOWER
Sink for ISNE = ISNESYSLOAD

Note: Purchasing and Selling entity must register Source and / or sink prior to creating a NERC e-tag

APPENDIX C: DETAILED INTERFACES

Common Name/ External Node	Transmission Provider	Associated Transmission Facilities
NB-NE .I.KESWICK 345 1	ISNE and MEPCO	Keswick - Orrington (396 Line)
Phase I/II .I.HQ_P1_P2345 5	Individual Owners	HQ - Comerford 451+452 Lines (Phase 1) HQ - Sandy Pond 3512+3521 Lines (Phase 2)
Highgate .I.HQHIGATE 120 2	ISNE	Bedford - Highgate Line (1429 Line) (Georgia Tap)
NY-NE .I.ROSETON 345 1	ISNE	Plattsburg - Sandbar Line (PV-20 Line) Whitehall - Blissville Line (K-37 Line) Hoosick - Bennington Line (K-6 Line) Rotterdam - Bearswamp Line (E205W Line) Alps - Berkshire Line (393 Line) Salisbury - Smithfield Line (690 Line) Pleasant Valley - Long Mountain Line (398 Line) Northport - Norwalk Harbor (1385 Line)
CSC .I.SHOREHAM138 99	ISNE and CSC	Shoreham - Halvarsson Converter (481 Line)

NY=New York , NE=New England, HQ=Hydro-Quebec, LI = Long Island-NY, CSC=Cross Sound Cable

APPENDIX D - Typical TTC And TRM Values For Non-PTF (Physical Based) Interfaces

Cross Sound Cable (New York)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	346	= TTC	0	346	= TTC
Monthly	346	= TTC	0	346	= TTC
Weekly	346	= TTC	0	346	= TTC
Daily	346	= TTC	0	346	= TTC
Hourly	346	= TTC	0	346	= TTC

ISNE (MEPCO)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	700	TTC – 700	0	600	TTC x .10
Monthly	700	TTC – 700	0	790	TTC x .10
Weekly	700	TTC – 700	0	714	TTC x .10
Daily	700	TTC – 700	0	746	TTC x .10
Hourly	Dependant on Forecast Load	TTC – 700	0	Historic	TTC x .10

MEPCO (New Brunswick)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	700	50	0	600	=TTC
Monthly	800	50	0	790	=TTC
Weekly	1000	50	0	714	=TTC
Daily	1086	50	0	746	=TTC
Hourly	Dependant on Forecast Load	50	0	Historic	=TTC

Phase I/II (Hydro Quebec) * Phase I and II are not posted separately.

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	1800	TTC - 1200	0	1200	500
Monthly	2000	TTC - 1200	0	1200	500
Weekly	2000	TTC - 1200	0	1200	500
Daily	2000	TTC - 1200	0	1200	500
Hourly	2000	TTC - 1200	0	1200	500

Highgate (Hydro Quebec)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	218	TTC - 200	0	20	= TTC
Monthly	225	TTC - 200	0	20	= TTC
Weekly	225	TTC - 200	0	20	= TTC
Daily	225	TTC - 200	0	20	= TTC
Hourly	225	TTC - 200	0	Dependant on Forecast Load	= TTC

Appendix 2

MISO Volume

1.0

Methodology for Determining Transfer Capability at the Midwest ISO

Version 1

Revision Date: 4/30/02

Note: This document is consistent with the 4/30/02 version of the MISO Whitepaper "Flow-Based Analysis in the Midwest ISO".

Table of Contents

1 Introduction

The following paper describes the Midwest ISO approach to Flow-Based analysis. This includes, but is not limited to the following:

A) Flow-Based Analysis Concepts

B) Information Needed for Flowed-Based Analysis

C) Development of Constrained Facilities

D) Development of Power Flow Models

E) Modeling Considerations and Time Frames

F) Use of OASIS Reservations and Schedules within the Model

G) Calculating AFCs

H) Treatment of Counter-Flows

I) Posting AFCs

J) Scenario Analyzer

K) Processing Requests for Transmission Service

This document summarizes the Midwest ISO approach to determining transfer capability and evaluating requests for transmission service. This is the process being used since the start of the MISO tariff. The process will continue to evolve over time but shall remain compliant with applicable NERC (or its successor organization) policies and standards. MISO operates in multiple NERC Regions and must recognize each Regions policies and standards. Where there are conflicts in the Regional policies and standards, MISO will work with the Regions and members on resolving those conflicts.

2 Definitions, Abbreviations and Acronyms

AFC – Available Flowgate Capability – The available capability in MW or MVA on a flowgate, which a transmission provider has determined, is for sale. The available capability determined is dependent on the generation, loads and transmission configuration assumed for the time period studied and therefore is referred to as a capability. The AFC accounts for all thermal, voltage and stability limits under both pre and post-contingency conditions, along with any TRM or CBM. There is no one set of source and sink points associated with an AFC. The AFC can be used to determine the amount of MWs that can be transferred between a specific set of source and sink points (i.e. the ATC) with respect to the flowgate, by dividing the AFC by its corresponding PTDF.

Critical Facility – Critical transmission facilities are (1.) all transmission facilities 230 kV and above and (2.) transmission facilities below 230 kV where outages of these facilities have been found to limit AFC on MISO flowgates or have resulted in TLR.

Flowgate – A term used in conjunction with the Interchange Distribution Calculator (IDC). Usually representing a constrained facility. The definition of constrained facility is contained in this paper, as well as Appendix 9C1A of the NERC Operating Manual. A NERC proposed definition is as follows: ***"A single or group of transmission elements (i.e., any transmission line or other transmission facility) for which Distribution Factors are calculated in the Interchange Distribution Calculator."***

Full AFC Calculation – A full AFC calculation (also referred to as a resynchronization) that occurs at set time intervals, calculates AFC values for specific time ranges, and relies on specific network models as the basis for calculations.

Integrated Control Center System (ICCS) — The MISO computer system designed to integrate the following: market interface, transmission market, transmission security, and settlement to serve both market participants and control areas.

OASIS Automation (OA) – MISO backend system used to post AFCs/ATCs on the MISO OASIS and to automatically process requests that are submitted on the MISO OASIS.

Operating Horizon – Period from current hour to 48 hours out where hourly AFC values are produced.

Planning Horizon – Period from end of Operating Horizon to 31 days out, where hourly AFC values are produced through day 7, and daily values are produced for days 8-31.

Resynchronization – See Full AFC Calculation

Study Horizon – Period from month 2 through month 36, where monthly AFC values are produced.

3 Determination of Transfer Capability

3.1 MISO Regional Tariff

MISO will implement a regional Open Access Transmission Tariff (hereinafter "Regional Tariff") 60 days following the successful demonstration of the ability of the MISO to begin providing Transmission Service (currently anticipated to be December 15, 2001). The regional tariff provides for both network integration transmission service and point-to-point transmission service.

The MISO staff has responsibility for administering the Regional Tariff. Administering the Regional Tariff involves calculating and posting available flowgate capacity (AFC), processing requests for transmission service, coordinating system impact studies and facility studies, verifying appropriate ancillary services have been arranged, facilitating an ancillary services market, allowing for customers to schedule use of the transmission service, and managing congestion.

3.2 Applying a Flow-based Approach at MISO

3.2.1 Flow-Based Concepts

MISO is using a flow-based approach to determine available flowgate capability (AFC) and to grant requests for transmission service under the regional tariff. A flow-based approach monitors flows on constrained facilities (sometimes called flowgates) that are known to experience excessive loading during transfers.

When a request for transmission service is received, it is evaluated by measuring the effects of the transfer on each constrained facility. One method for making this kind of evaluation is to make a series of linear analyses prior to receipt of a request. The linear analyses develop a series of response factors that indicate the change in the flow on a constrained facility for transfers between each source/sink pair. When the request is received, the response factors are used to measure the incremental loading on all significantly affected constrained facilities. If one of the constrained facilities experiences a loading that exceeds its rating, the transmission service request cannot be approved without taking other steps that would reduce the loading level on the constrained facility.

3.2.2 Use of OASIS Automation

MISO has procured an energy management system (EMS) advanced application package to administer the security functions at MISO. As an integral part of the EMS acquisition, MISO received software called OASIS Automation (OA). MISO will use the OASIS Automation software to automatically process requests for transmission service using a flow-based approach and to determine AFC on constrained facilities. This process is integrated with the MISO EMS by using power flow models developed from the real-time system. OASIS Automation automates the transmission reservation processing and energy schedule processing while minimizing operator involvement in the process.

A flow-based approach determines AFC of constrained facilities. Constrained facility AFC represents the capacity remaining on constrained facilities after reduction for base-flows, previously approved transmission service requests and a margin (if appropriate). Requests for transmission service are made on a point-to-point basis from POR(s) to POD(s). However, AFCs are determined on a constrained facility basis. In order to evaluate a transmission service request, response factors are used to decrease the AFCs of constrained facilities. If the AFCs of all constrained facilities are positive after decrementing, the interconnected network has capability to accommodate the request.

Constrained facilities are monitored by OASIS Automation such that when a request for transmission service is made, the effects of the transfer on the 15 most limiting constrained facilities are determined. OA identifies the 15 most limiting constrained facilities for each source/sink pair that MISO can sell transmission service. The 15 most limiting constrained facilities represent facilities that have the lowest ATCs for the source/sink pair. The 15 most limiting constrained facilities may be different for each time interval of the AFC calculation. The 15 most limiting constrained facilities must exceed a threshold sensitivity factor established by MISO. The threshold response factor may be different for OTDF versus PTDF constrained facilities. If OA cannot find at least 15 constrained facilities with sensitivity factors that exceed the threshold, less than 15 constrained facilities are included in the review. If the AFC on any of the constrained facilities becomes negative, that request cannot be approved without taking other steps to provide additional AFC (i.e., preemption, displacement or curtailment).

The list of constrained facilities includes all facilities for which TLR could be requested within MISO as well as facilities within bordering RTOs where MISO could be expected to respond to a TLR request. MISO recognizes limits and the corresponding response factor cutoff on constrained facilities outside MISO to the extent these same limits are honored by the RTO where the constrained facility is located. MISO uses the same list of constrained facilities in the NERC IDC and OASIS Automation. MISO does not restrict the number of constrained facilities other than to require that they also be represented in the IDC. MISO anticipates that initially, there may be a tendency to define a large number of constrained facilities. MISO believes that, over time, this number can be reduced if experience shows we are not experiencing loading limits on all these facilities and it is understood that new constrained facilities can be added "on-the-fly" as system conditions change and new problems appear.

MISO has defined three time periods for posting of AFCs and the subsequent evaluation of AFCs when processing transmission service requests:

- **Operating Horizon –** Hourly values from current hour to 48 hours out.

- **Planning Horizon** – Hourly values from the end of operating horizon to 7 days out and daily values for days 8-31.

- **Study Horizon –** Monthly values for month 2 to month 36.

Within the operating horizon, a further distinction can be made between the time when schedules are available (current day and, after 3 pm, next day) and the time when reservations are available (all other times).

3.3 Calculation of AFCs

OASIS Automation's Full ATC Calculation process uses a solved AC power flow base case as the starting point for an AFC calculation. The Full ATC Calculation determines AFC on pre-defined constrained facilities by subtracting from each constrained facility Operating Security Limit the following quantities: a) MW flow on the constrained facility (this is taken from the solved power flow case), b) TRM value (derived from network quantities), and c) CBM value (derived from network quantities).

The AFC calculation described above is applied to all MISO constrained facilities identified as PTDF flowgates, i.e. flowgates having monitored element only. For OTDF flowgates, i.e. flowgates having monitored and contingency elements, the Full ATC Calculation computes the post-contingency MW flow on the monitored element due to a pre-defined single contingency, compares it to the emergency rating of that element, and performs the AFC calculation as described above.

For a small number of MISO constrained facilities, a voltage stability analysis using P-V curves or similar technique will be required to determine maximum MW loading on these constrained facilities. The voltage stability analysis for each constrained facility shall take into account: a) a pre-defined set of single contingencies and b) a pre-defined transfer direction to stress the system. Once the maximum MW loading for the voltage constrained facilities have been determined, the Full ATC Calculation compares these values with the thermal limits and the lower value is used in AFC calculation.

3.3.1 AFC Coordination

MISO is having discussions with bordering RTOs on coordination of AFCs. Each RTO will calculate AFCs for its own constrained facilities and will post this information for use by the other RTOs. Depending on the frequency of updates, the RTOs will either use the posted AFCs or their own calculated AFCs as they sell transmission service. Each RTO will still be responsible for determining response factors for foreign constrained facilities. Attachment A contains an Inter-RTO Coordination process developed by Alliance Companies, MISO and SPP. MISO Carmel currently reads AFCs once an hour from SPP and MISO St Paul. The AFCs computed by MISO Carmel are overwritten with values from SPP and MISO St Paul. MISO Carmel continues to work on improvements to the AFC calculation. At such time in the future when it is getting good AFCs for the MAPP region constrained facilities, MISO

Carmel will stop overwriting AFCs from MISO St Paul. It is also anticipated that once the merger between MISO and SPP in complete, there will only be a single AFC calculation for the entire organization.

MISO continues to have discussions with the Alliance Companies on the coordination of AFCs for summer 2002. MISO has added Alliance Company constrained facilities to the MISO list and has a detailed representation of the Alliance Companies in its network model. MISO gets schedules from the tag dump once an hour and reads reservations from the ECAR and MAIN ftp sites for use as CA net interchange. There is currently no exchange of AFCs between Alliance Companies and MISO although MISO has had discussions on a limited amount of AFC coordination with Alliance Companies in MAIN.

4 Posting of Flowgate AFC'S

The frequency of periodic AFC calculations are as follows:

1) Hourly for next 48 hours

2) Every 6 hours, hourly models for days 3 through 7

3) Daily on-peak models for days 8 through 31

4) Weekly, monthly models for months 2 through 36

The results of these calculations are posted on the MISO OASIS site based on the frequency stated above. In order to be updated on OASIS, the AFC must change by more than 10%. If the Full ATC Calculation results in an AFC that has not changed by more than 10%, the OASIS value is not updated and the time of last update posted on the OASIS remains fixed. Historical data for the past three years shall be available on OASIS.

Resynchronization of data takes place either on a timed basis, manual basis or an automatic trigger basis. The timed basis takes place each hour (hourly resynchronization) for the operating horizon and once a day (daily resynchronization) for the planning horizon. The manual resynchronization is on demand and the automatic trigger resynchronization takes place when there is a significant change in the flow on a flowgate.

At the beginning of each hour, an hourly resynchronization takes place for the operating timeframe. Hourly resynchronization takes approximately 15 minutes to complete and produces constrained facility AFCs that reflect system and transmission service changes since the last resynchronization. After hourly resynchronization starts, OASIS Automation continues to use the constrained facility AFC at the start of resynchronization to process requests for transmission service. Once resynchronization is complete, operating horizon AFCs from the resynchronization process will be decremented to reflect transmission service requests that were processed during resynchronization. Daily resynchronization takes approximately 2 hours to complete and produces constrained facility AFCs that reflect system and transmission service changes since the last resynchronization. After daily resynchronization starts, OASIS Automation continues to use the constrained facility AFC at the start of resynchronization to process requests for transmission service. This means OASIS Automation acts on requests even when resynchronization is underway. Once resynchronization is complete, planning horizon AFCs from the resynchronization process will be decremented to reflect transmission service requests that were processed during resynchronization.

Automatic trigger resynchronization takes place when there is a significant increase or decrease in the flow on a flowgate. For an increase/decrease of 30-50%, the AFC will be adjusted by the amount of the change. For a change in AFC of 50-70%, a total resynchronization will take place. These percentages are in percent of flowgate rating, not percent of flow, and are configurable in the OASIS Automation input file.

For certain flowgates, the AFC will be automatically set to 0, if the flow on the flowgate is 0 MW.

The posted information shall reflect the current status of the transmission system, taking into account approved and confirmed transmission capacity reservations. The frequency for calculating AFC shall range from hourly for the operating horizon to daily and/or weekly for the planning horizon.

4.1 Use of Scenario Analyzer

The flow-based approach being used to process requests under the regional tariff requires computing constrained facility AFC for the planning horizon and the operating horizon. Constrained facility AFC represents remaining capacity available on a constrained facility. MISO is posting AFCs as a product of its flow-based analysis and will not be posting CA to CA ATC[1]. However, transmission customers are interested in knowing CA to CA ATC, not capacity that is available on a constrained facility. To meet the needs of customers, MISO has provided a Scenario Analyzer which allows transmission customers to enter transmission service requests for analysis of available capacity without submitting requests on OASIS. The Scenario Analyzer will evaluate availability of capacity on the 15 most limiting constrained facilities for a source/sink pair but will not decrement AFC since no request has been submitted. To access the Scenario Analyzer, a request is completed using an OASIS request entry form and the Analyze button is pushed. The Scenario Analyzer performs the following functions.

- Provide feedback to the user if the request is ok.
- If the request is not ok, the Scenario Analyzer will provide feedback as to what hours and or days the request is not ok. It will report the limiting facility, the amount of AFC that is still available and the amount of CA to CA ATC that is still available.

[1] MISO has committed to post ATCs for interfaces involving the Cinergy Hub.

As part of the agreement on the Cinergy Hub, MISO is posting ATCs between each MISO CA and the Cinergy Hub. The ATCs are needed by users of the Hub to demonstrate whether firm transmission capacity was available at the time they completed their obligations to the Hub.

5 Models Supporting AFC Calculations

MISO uses OASIS Automation to determine AFCs during the operating and planning horizons and to automatically process transmission service requests. OASIS Automation has a link between the real-time system and the reserving and scheduling of transmission service under the regional tariff. This link is established through the power flow model, which has its origin from a state estimator snapshot of the real-time system.

OASIS Automation creates hourly power flow models for the first seven days and daily power flow models for days 8 through 31. The power flow models are used to determine constrained facility AFC (both firm and non-firm) and response factors for the operating horizon and the planning horizon. Response factors represent the increased flow on a constrained facility for a transfer from a source to a sink. At least once a day for the planning horizon and once an hour for the operating horizon, a power flow model is used to establish new constrained facility AFC values and new response factors. Changes in topology for the time period are reflected in the new response factors while changes in load; generation dispatch; approved schedules; and study, accepted and confirmed reservations are reflected in the new AFC values. This process of updating AFC values and determining new response factors is considered a resynchronization of data. Corresponding power flow models must be created for each time interval to compute constrained facility AFC and response factors.

During resynchronization, OASIS Automation takes the current state estimator snapshot as a beginning point for model development. The state estimator snapshot is adjusted to be more representative of the period under review by varying the load according to forecasts, using the outage scheduler to consider the status of generator and transmission facilities, using schedules to represent interchange during the operating horizon, using reservations to represent interchange during the planning horizon and setting generation to match load plus interchange requirements.

OASIS Automation computes constrained facility AFCs and response factors for 31 days using a snapshot off the real-time system. A network model builder will be used to develop monthly planning models for months 2 through 36 starting with the most up-to-date model available (e.g. NERC MMWG models, MAIN summer and winter seasonal models). Before the models are used for a study, updates will be requested from the transmission owners. Once the monthly models are developed, the same OASIS Automation algorithms are applied to determine constrained facility AFCs and response factors for months 2 through 36.

Requests for transmission service made on OASIS will be automatically processed by OASIS Automation. Automatically processed means OASIS Automation will validate information on the request and, if it passes validation, will make a constrained facility AFC review to check the AFC on the 15 most limiting constrained facilities. Validation of information includes verifying appropriate source, sink, POR and POD has been used.

Because the regional tariff has different revenue allocation formula depending on whether native load or a wholesale customer load is being served within a MISO CA, the source and sink information on the OASIS request are the identity of a CA or an entity within a CA. The entity can be a municipal system, an electric cooperative, an IPP or the CA itself. However, the entity must have load and/or generation that can be uniquely identified within the CA. This set of entities has been defined for MISO CAs and could be defined in a similar manner for non-MISO first-tier CAs. In general, this set of entities are not individual generator buses or load buses. However, an IPP that is a single generator within a CA may be represented as a single generator bus.

MISO requires source and sink information be included on OASIS requests in order to make a flow-based review. For sources and sinks within the MISO footprint, MISO has included drop-down lists on its OASIS request form with all MISO entities. MISO has used the convention of CA.Zone.Subzone to identify these entities. For sources and sinks outside the MISO footprint, the sources and sinks can be CAs or can be entities within CAs. MISO has included full model detail of all CAs that are first-tier to MISO (non-MISO CAs that interconnect with a MISO CA) and will utilize these CAs in its flow-based review process. If the source and/or sink are non-MISO CAs that extends beyond the first tier, they may not have a detailed representation in the MISO models. For those sources and sinks that do not have a detailed representation, MISO has created an electrical equivalent mapping table that maps the non-MISO CAs to ones that have detailed representations.

The valid list of all PORs and PODs are all MISO CAs and non-MISO first-tier CAs. The valid list of all sources and sinks are all entities within MISO CAs and non-MISO first-tier CAs. It also includes all other CAs that are beyond non-MISO first-tier CAs. If the transmission service is a transaction with a source or sink beyond the non-MISO first–tier CAs, the source or sink will be the CA which is the actual source or sink and the POR or POD will be a non-MIOSO first-tier CA.

How MISO models the sources and sinks establishes the level of granularity MISO uses in its flow-based approach. There are two levels of granularity MISO has considered.

In the first level, MISO would not use a finer granularity than a CA when making a constrained facility review. OASIS Automation reads the source or sink on a request. If it does not recognize the source or sink as a CA, it defaults to use the CAs of the POR or POD. The review of the 15 most limiting constrained facilities uses the selected CAs to determine impacts on constrained facilities. For this level, entities smaller than a CA are not uniquely modeled and response factors to/from these entities are not determined. This flow-based approach uses the same level of granularity as the IDC.

In the second level, the entities within MISO CAs and non-MISO first-tier CAs are represented as zones in the models and response factors to/from the zones are determined. This second approach results in an improved determination of impacts on constrained facilities. However, some issues must be resolved before this level can be implemented. These issues include how you represent schedules that involve zones (this is currently not available on tags). Using zones instead of CAs will increase the number of response factors that must be calculated with each resynchronization. This flow-based approach does not use the same granularity as the IDC, which means we are granting transmission service at one level of granularity but we are curtailing transmission service (NERC TLR) at another level of granularity.

This Methodology describes evaluating ATC between two CAs represented by the source and the sink on the request. Depending on the level of granularity utilized in the future, MISO may be evaluating ATC between two entities that are at a finer level of granularity than a CA.

5.1 Information Needed for Flow-Based Analysis

The ability to determine credible constrained facility AFC for the next 31 days is dependent on having a valid state estimator snapshot to use as a starting point in building the power flow model and on having valid near-term planning data that provides an operations plan through the operations and planning horizons.

OASIS Automation is used to determine AFC and automatically process transmission service requests for the first 31 days. OASIS Automation is the link between the real-time system and the reserving and scheduling of transmission service under the regional tariff. This link is established through the power flow model which has its origin from a state estimator snapshot of the real-time system. The power flow model is used to determine constrained facility AFC and response factors for the operating horizon and the planning horizon. The study horizon uses NERC MMWG planning models as the initial power flow model used to calculate AFC and process transmission service requests.

For this flow-based approach to be successful, it is critical that MISO have a detailed network model for all MISO CAs and is receiving real-time data (both statuses and analogs) at a frequency that provides a successful state estimator solution.

Power flow models are developed for future time periods using the state estimator snapshot as the initial model for day 1 through day 31, and using a PSS/E NERC MMWG based model for the period beyond 31 days. The time periods of the models developed coincides with the AFC posting requirements on OASIS. These include hourly AFCs for days 1 through 7, daily AFC for days 8 through 31 and monthly AFCs for months 2 through 36. MISO CAs must provide near-term planning data in order to create power flow models that are representative of the time period of interest.

- Load forecasts are needed from MISO CAs. Hourly forecasts for the first 7 days, daily forecasts for days 8 through 31 and monthly forecasts for months 2 through 36. MISO utilizes a third party short-term load forecasting tool to supplement CA forecast information not provided for the first 7 days. MISO has a trending tool that can be used to develop approximations of long-term forecasts (beyond the first 7 days).

MISO only uses its forecasting tools when a MISO CA does not supply its forecast and for non-MISO CAs.

- Generator outages and transmission facility outages for MISO CAs come from requests for maintenance submitted to MISO. Even though MISO only requires approval of critical facility maintenance outages, MISO must receive notification of all facility outages to include their effect in the power flow model.

- MISO has access to schedules through the electronic scheduling system (ESS) and access to reservations through OASIS. MISO CAs must have all reservations in OASIS (even those that are pre-open access) and must have all interchange transactions tagged and submitted to MISO. Otherwise, the MISO automated tools are unaware of these uses of the transmission system and will not consider them when approving requests for transmission service.

- Generator unit commitment or block loading orders for the next 7 days are needed. MISO prefers that unit commitment information be provided but will use generator block loading information to create a MISO unit commitment. Generators are dispatched according to block loading order in power flow models used to simulate future periods.

- Planned system upgrade information must be included in future system models.

MISO is having discussions with bordering RTOs on exchanging power flow information that can be used in each RTO's AFC calculation process. MISO is working with Alliance Companies, SPP and TVA on the type of information to be exchanged and its format.

5.2 Development of Power Flow Models

OASIS Automation uses the power flow model to determine AFC and to calculate response factors. This means that at least once a day for the planning horizon and at least once each hour for the operating horizon, the power flow model is used to establish new constrained facility AFC values. Any changes in topology are reflected in new response factors. This process of updating AFC values and determining new response factors is considered a resynchronization of data. Corresponding power flow models must be created for each time interval to compute constrained facility AFC and response factors.

5.2.1 Load Forecasts

During resynchronization, OASIS Automation takes the current state estimator snapshot as a beginning point for model development. An off-line load-forecasting program projects future CA peak loads if the CAs have not supplied them. The EMS Load Model Subroutine uses the peak load projections and its load allocation algorithm to create an hourly load profile that assigns loads to individual buses.

5.2.2 Use of OASIS Reservations and Schedules within the Model

Depending on whether it is in the operating horizon or the planning horizon, the next step in model development is the inclusion of interchange. OASIS Automation creates 48 hourly power flow models for the operating horizon and creates these models once an hour. Schedules will be used in the operating horizon to set CA net interchange and reservations will be used in the operating, planning and study horizons to set CA net interchange for times when schedules are not available. MISO CA schedules are obtained once-an-hour from the Electronic Scheduling System (ESS). Non-MISO CA schedules are obtained once-an-hour by summing all schedules in the NERC tag dump. Hourly non-firm transmission service can be purchased during the time period when schedules are available. However, there is usually a time lag between the time when the reservation is confirmed and a schedule is submitted. Therefore, hourly non-firm reservations are used in power flow models until schedules are submitted.

OASIS Automation creates hourly power flow models for day 2 through day 7 every 6 hours and creates daily power flow models for day 8 through day 31 once a day. These models include all study, accepted and confirmed reservations on the MISO OASIS node. There may be instances when duplicate reservations appear on the MISO OASIS node. An OASIS Automation input file can be used to exclude certain OASIS reservations.

MISO reservations are obtained from OASIS. These include transmission service sold under the MISO tariff and grandfathered transmission service on the TO pages of the MISO OASIS node. MISO has also agreed to use reservations from other transmission providers in its AFC calculation. Attachment A contains the ATC Coordination document that describes the agreement to exchange near-term planning data and coordinate AFCs with other TPs. MISO uses a software program called the ATC Coordination Tool to obtain reservations and AFCs from other TPs. MISO is currently obtaining reservations from SPP, St Paul, Alliance Companies in MAIN and Alliance Companies in ECAR. The reservations must be screened to remove duplicate reservations for the same service that appears on multiple OASIS sites and partial path service that has been sold by other transmission providers but not by MISO. Attachment B contains the screening logic that has been applied by MISO in this use of the ATC Coordination Tool.

The Network Model Building System (MBS) creates monthly power flow models for months 2 through 36 using seasonal NERC MMWG models modified with input from Transmission Owners. The MBS is used to generate updated monthly models applying the same reservation information as is applied to the shorter term models.

5.2.3 Use of Generation and Transmission Outages in The Model

The next step in model development is to include the effects of generation and transmission outages. MISO's Outage Scheduler will restore facilities that are out of service when the state estimator snapshot was taken and removes facilities that are scheduled out of service after the state estimator snapshot was taken. The Outage Scheduler contains all generation and transmission outages that have been entered by MISO members. These outages are used in the model. Likewise, all non-MISO outages are obtained from the SDX.

5.2.4 Generator Unit Commitment or Block Loading

The final step in model development is setting generation to match load plus interchange requirements. MISO is receiving unit commitment information from MISO members that have this capability. For those that do not have this capability, MISO is receiving either block loading information or merit order information. MISO runs its own unit commitment program once an hour using load forecast, CA net interchange and generation information from the CAs. The results of the MISO unit commitment is used in the model.

5.2.5 Participation Points

MISO uses participating points to calculate response factors. The response factors are used to determine whether a transmission service request meets the threshold when evaluating its impact on OTDF and PTDF flowgates. The response factors are also used to decrement AFCs on flowgates during the time intervals between resynchronization of the data. MISO follows the same practice as the IDC in that all generators are included as participation points except nuclear units and units on outage in the data base.

5.3 Modeling Considerations and Timeframes

OASIS Automation is used to develop power flow models in the operating and planning horizon. Power flow models are developed for each time period that is required for AFC postings and are done at a frequency that meets the AFC update requirements established by MISO.

MISO generates hourly and daily models from the real-time node-oriented model on the following frequency: ***Operating and Planning Horizon*** - (Node/Breaker-oriented):

- Hourly (user-adjustable periodicity, hourly increments only with a minimum of once an hour) for the next 48 hours

- Every 6 hours, (user-adjustable periodicity, hourly increments only, not more often than once every 6 hours for performance compliance) build hourly models for days 3 through 7.

- Daily on-peak models for the next 31 days (beyond first week, days 8 thru 31)

The MISO generates monthly models, from a modified MMWG bus/branch oriented model on the following frequency: ***Study Horizon*** - (Bus/Branch-oriented):

- Monthly for the next three years (36 on-peak models).

The real-time model is used to generate base flows of constrained facilities to be studied in the hourly time frame. MISO maintains the real-time model database. All outages, scheduled and un-scheduled, are entered by the individual entities through an appropriate user interface. The transmission owners supply hourly load projections through hour 168. In the absence of this data, MISO generates a 168-hour profile utilizing third party software.

Long-term models beyond 36 months are developed from NERC MMWG models, updated with regional and/or TO provided models.

6 Treatment of Partial Path Reservations

There are at least three different situations where a partial path reservation must be considered. Each situation is discussed below.

The first situation occurs when an entity has bought a segment of transmission service from CA A to CA B. If at a later time, they would like to go from CA B to CA C as part of the same transaction, they have a number of choices. The first choice is if they have firm transmission service, they can use a firm redirect from a POR of CA B to a POD of CA C. If they make a firm redirect, they release all rights they have to use the original reservation during the time period of the redirect. If they want to go-back during the time period of the redirect, it is equivalent to a new request being placed in the queue. The second choice is if they have firm transmission service, they can use a non-firm redirect that has a TLR curtailment priority of 1. The third choice is they could just buy another segment of transmission service from CA B to CA C. MISO will allow two or more segments of transmission service to be put together in a single transaction provided they form a contiguous path with no breaks along the path. MISO has a partial path methodology that states when at least one of the segments has the true source and true sink as part of the reservation, the schedule will be accepted to the extent there is not TLR underway that prevents accepting the schedule. If none of the segments has the true source and true sink as part of the reservation, the schedule will have a constrained facility review performed at the time it is submitted and if there is constrained facility capacity available, the schedule will be accepted and it will be subject to the same treatment as all other schedules with the same priority of transmission service. If none of the segments has the true source and true sink as part of the reservation and the constrained facility review finds there is insufficient constrained facility capacity available, the schedule will be denied. The only exception is for transactions that involve use of the Cinergy Hub. Under the Cinergy Hub Agreement, Cinergy Hub transactions using multiple segments of MISO transmission service where no one segment contains the true source and the true sink, will be accepted even if they fail the constrained facility review with the understanding the transaction is not subject to MISO redispatch.

The second situation occurs when a transmission provider sells a segment of transmission service up to its border and there is no corresponding transmission service sold from the adjoining transmission provider. The transmission provider that sold the service must honor the transmission service it sold by decrementing AFC on its flowgates. The adjoining transmission provider will not make any adjustments to its flowgates until it has sold transmission service on its system. MISO will coordinate partial path reservations with other RTOs using this method

The third situation occurs when MISO reviews a request for transmission service that requires service from other TPs to complete the path. If MISO identifies a flowgate limit on the other TP system and finds no other limits, MISO will approve the service with the understanding that the other TP must review this same request and they will decide whether to accept the service with some form of mitigation. MISO will not deny service where the limit is on the system of another TP that must also approve the service to complete the path. In all other cases where MISO reviews a request and finds a flowgate limit on other systems, MISO will deny the service.

7 Netting of Reservations (treatment of counter-flows)

When calculating firm AFCs and when reviewing requests for firm service using a flow-based analysis, counter-flow reservations will not normally be considered. When calculating non-firm AFCs and when reviewing requests for non-firm service, MISO will consider 50% firm and non-firm counter-flow reservations.

MISO is concerned that this treatment of counter-flows is extremely conservative in that it assumes 100% of all positive impacting reservations will be scheduled all of the time and 0% of the counter-flowing reservations will be scheduled. This conservative estimate has resulted in a large number of negative AFCs for constrained facilities that have historically not been a problem. MISO has had its AFC calculation process challenged because many of the previous ATC calculation made by other TPs included 100% counter-flows. MISO believes it could use a less conservative approach in its treatment of counter-flows and the amount of positive impacts from confirmed reservations without causing an increase in TLR. MISO has had discussion at both the Operations Support Group and the AFC WG meetings on this topic.

When reviewing requests for non-firm transmission service in the operating horizon, counter-flows resulting from firm and non-firm schedules will be considered.

8 Development of Constrained Facilities (Flowgates)

Constrained facilities are monitored by OASIS Automation such that when a request is made for transmission service, the effects of the transfer on the 15 most limiting constrained facilities are determined. If the AFC on any of the constrained facilities becomes negative, that request cannot be approved without taking other steps to provide additional AFC (i.e., preemption, displacement or curtailment).

OASIS Automation only considers the effects on the 15 most limiting constrained facilities at the time a request is made because of the number of response factors that must be stored for the different time horizons. The effects on all constrained facilities are considered during the next periodic update of AFCs and response factors. The 15 most limiting constrained facilities are the set of constrained facilities whose combination of pre-transfer loadings and response factors cause them to reach their operating security limit with the smallest amount of transfer. Effectively, these are the 15 constrained facilities with the lowest ATCs.

The list of constrained facilities should include all facilities for which NERC TLR could be requested within MISO as well as facilities within bordering RTOs where MISO could be expected to respond to a NERC TLR requests. MISO uses the same list of constrained facilities in the NERC IDC and OASIS Automation. MISO recognizes limits on constrained facilities outside MISO to the extent these same limits are honored by the RTO where the constrained facility is located.

MISO performs a network analysis to evaluate firm transmission service for 1 month or longer and identifies additional constrained facility that may be needed when network analysis reviews are performed. When new constrained facilities are needed, MISO will add them to the process and to the IDC. This firm analysis includes reviews of all contingencies and monitored elements that meet the planning practices of the transmission owners. Line-generator contingencies and other double contingencies will be analyzed off-line or, if designated as constrained facilities, will be exempt from being required to be in the IDC.

At least daily, MISO performs security reviews using power flow models for the current day and next day and performs critical facility and generator unit maintenance reviews on an as-needed basis. These additional studies are also used to identify the need for additional constrained facilities.

Transmission owners indicate to MISO when new constrained facilities must be added because the system configuration has changed and new facilities are to be considered when posting AFC and granting requests for transmission service.

MISO is working with the transmission owners to make sure the list of constrained facilities are kept up-to-date such that as system conditions change and as constrained facilities are no longer needed, they will be removed. MISO is making sure the constrained facilities in the IDC are consistent with the constrained facilities MISO uses in its processes.

MISO indicated at the April 28, 2000 Operations Support Group meeting that with all of the other regional tariff implementation details being addressed, there was not sufficient time for MISO to also develop a MISO-wide TRM/CBM policy. MISO proposed that the TOs identify constrained facilities, their ratings, TRM and CBM that can be used for a Day 1 implementation and MISO will have the right to review this information. MISO asked at the September 11, 2000 Operations Support Group meeting that the list of constrained facilities be submitted to MISO by December 31, 2000. MISO made a commitment to have a TRM/CBM policy by June 1, 2002.

Until a MISO-wide TRM/CBM policy can be adopted, MISO transmission owners are using their regional methodologies to determine TRM and CBM. MISO's review of TRM/CBM is limited to verification the regional methodologies have been followed. If a MISO review results in TRM or CBM questions involving a transmission owner from one of its regions, MISO will work with the region to resolve questions.

MISO has honored constrained facilities submitted by the TO's for Day 1 implementation. MISO understands that initially, there may be a tendency to define a large number of constrained facilities. MISO believes that over time, this number can be reduced if experience shows we are not experiencing loading limits on all these facilities and it is understood that new constrained facilities can be added "on-the-fly" as system conditions change and new problems appear.

MISO uses a 3% OTDF cutoff and a 5% PTDF cutoff when processing transmission service requests. The use of different cutoffs for PTDF and OTDF flowgates was a compromise agreement reached at an OSG meeting. Historically, the MAPP region has exclusively used PTDF flowgates with a 5% cutoff while the MAIN region has predominantly used OTDF flowgates with a 3% cutoff. The compromise agreement was the use of 3% for OTDF flowgates and the use of 5% for PTDF flowgates.

9 Processing Requests for Transmission Service

All requests for regional transmission service must be made on the OASIS. OASIS Automation is capable of automatically processing transmission service requests using a constrained facility AFC review for up-to the next 36 months. There is a difference in the model used to develop the constrained facility AFC and response factors depending on whether the request is within the next 31 days or extends beyond the next 31 days. If the transmission service request is totally within the next 31 days, the constrained facility AFC and response factors come from a power flow model developed from a snap-shot of the real-time system. If the transmission service request extends beyond the next 31 days but is within 36 months, the constrained facility AFC and response factors come from a NERC MMWG model that represents peak conditions for the month. If the transmission request extends beyond 36 months, a constrained facility AFC review can still be performed but it will require manual processing. OASIS Automation cannot automatically process requests that extend beyond the next 36 months.

MISO also performs a network analysis of firm transmission service requests that are one month or longer. A network analysis is made using the power flow models developed during resynchronization. The network analysis looks for thermal loading limits, voltage limits and stability limits.

Firm transmission service requests that overlap the 36 months (part of the request is within and part of the request is outside the 36 months) will have a constrained facility AFC review automatically performed by OASIS Automation and will have a network analysis review performed manually for the part of the request that is within the first 36 months. For the part of the request that is outside the first 36 months, a manual constrained facility AFC review and a manual network analysis review will be performed.

For requests that have both a constrained facility AFC review and a network analysis review performed, both reviews must indicate transmission capacity is available before the request can be approved. If either evaluation indicates insufficient transmission capacity exists, a system impact study may be made to identify remedial actions that can be taken to approve the request (at the request of the transmission customer). If a network analysis finds limiting facilities that are not in the list of flowgates, they will be added as new flowgates.

OASIS Automation has the capability to automatically process a transmission service request using a constrained facility AFC review if the request is totally within the 36 months. All requests that are totally within the 36 months will be processed automatically after they have been entered on the OASIS. Processing a request includes validating information on the request and verifying there is adequate capacity on the 15 most limiting constrained facilities to accommodate the request.

All non-firm requests will have an OASIS Automation flag set to automatically approve the request if it passes the information validation and if there is adequate capacity to accommodate the request after decrementing AFC using response factors. If the adjusted AFCs are all positive for the duration of the request, the request status will be changed to "Accepted" ("Confirmed" if the request has been pre-confirmed). If one of the AFCs is negative, the request status will be changed to "Study" and the tariff administrator will receive an alarm to manually process this request. The tariff administrator will review the request to decide whether other steps can be taken that would allow the request to be approved (preemption of other lower priority requests, offering a higher price compared to other equal priority requests or some form of market redispatch).

All firm request will have an OASIS Automation flag set to not automatically approve the request if it passes the information validation and there is adequate capacity on the 15 most limiting constrained facilities. After the request has completed a constrained facility AFC review, whether the adjusted AFCs are positive or negative for all hours of the request, the request status will be changed to "study". A tariff administrator will then review the request. If the firm request is within 31 days of the current day, the tariff administrator will either change the status to "accepted" if AFC is positive on the 15 most limiting constrained facilities for the duration of the request or will decide whether other steps can be taken that would allow the request to be approved (preemption of other firm requests of a shorter duration that have conditional approval or the availability of market redispatch).

If the firm request is for the period beyond 31 days, the tariff administrator will make the same reviews of the results of the constrained facility AFC review, but must also review the results of a network analysis review. Both analyses must indicate transmission capacity is available prior to approving the request. If either review finds that there is not enough transmission capacity, the tariff administrator will consider preemption or redispatch options available to approve the request. If these steps do not permit approval of the request, the tariff administrator will inform the transmission customer that an Impact Study will be required to determine any facility additions or upgrades that may be required to provide the requested service.

Until MISO is confident the AFCs are good, the OASIS Automation flag will not be set to automatically approve or automatically deny a request. There may be other reasons why the OASIS Automation flag is set to not automatically approve a request. This would be done if it is a firm request and a deposit is required or if a check for some type of contract path limit may exist. MISO is performing a flow-based analysis but will recognize contract path limits in three circumstances:

- Transactions into, out-of or across MISO will recognize a contract path limit between MISO and its first-tier CAs.
- If a transaction is across a controllable device (i.e., a DC line) the size of the controllable device will be treated the same as a contract path limit.
- If a MISO CA is not directly connected to other MISO CAs and there is some transmission arrangement between them and other MISO CAs, the capacity of the transmission arrangement will be treated as if it is a contract path limit.

OASIS Automation automatically decrements AFC on the 15 most limiting flowgates for requests with status of Study, Accepted or Confirmed. The decrementing is done at the time the change in status occurs and the 15 most limiting flowgates have their AFC updated on the OASIS. At the next resynchronization, the reservation is included in the base case and its effects on all flowgates are considered.

MISO is investigating not including study requests in the power flow models used to calculate AFCs. MISO would only include accepted and confirmed reservations. The base flows produced from these models will not contain the impacts of study requests. After the base flows are passed to OASIS Automation, an adjustment will be made to the 15 most limiting constrained facilities for a source/sink pair to remove the effects of study requests. The adjusted values will be used to post AFCs on the OASIS, to automatically evaluate requests using OASIS Automation and to respond to Scenario Analyzer submissions.

Attachment A
ATC COORDINATION WITH OTHER TRANSMISSION PROVIDERS

ARTO, MISO, SPP ATC 'COORDINATION' DOCUMENT

May 25, 2001

Final Draft

Purpose and Background

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its ruling on the voluntary establishment of Regional Transmission Organizations (RTOs). This ruling, Order 2000, establishes a set of minimum characteristics and functions required of all RTOs. One of the functions required of RTOs by Order 2000 is Interregional Coordination. To fulfill this function, FERC requires that the RTO must ensure the integration of reliability practices within an Interconnection and market interface practices among regions. The integration of market interface practices among regions includes the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures. The RTO is required to develop mechanisms to coordinate their activities with other regions. While it is not required to include the mechanisms at the time of RTO application, reporting requirements must be proposed by the RTO to provide follow-up details for how the RTO is meeting the coordination requirements.

Representatives from the Alliance RTO (ARTO), Midwest Independent System Operator (MISO), and Southwest Power Pool (SPP) have been involved in a collaborative process to detail the data exchange requirements and mechanisms, data usage principles, and coordination of methodologies necessary to calculate TTC and ATC values for a seamless market interface across the ARTO, MISO, and SPP borders. This document describes the agreements reached by the three RTOs to facilitate fulfillment of this specific coordination requirement imposed by Order 2000 on all RTOs.

I. Data Exchange

The vast Eastern Interconnection is highly integrated and capable of reliably transmitting energy over long distances. The operational control of this Interconnection is distributed among various transmission providers and control area operators. The localization of control is accomplished effectively on a regional basis by RTOs, which provide the direct supervision necessary to respond to transmission contingencies and operational emergencies in a swift and effective manner. Typically, these contingencies will impact the operation in the vicinity of the contingency. For example, the status of the transmission system in New England has very little impact on the operation of the transmission systems in the Mid-Continent and Southern regions. However, one should not conclude that each of these transmission systems can or should operate independently. Since the Eastern Interconnection connects all transmission systems within the Interconnection, the conditions within one region can impact the loadings, voltages and stability of others within the Interconnection. The magnitude of this impact is a function of generation status (including the generation serving specific loads), transmission configuration, and load level. Since the operation of one system will impact the operation of neighboring systems, data must be exchanged in order to maintain the reliability of the Interconnection.

The calculation of Total Transfer Capability and Available Transfer Capability is a forecast of transmission capacity that may be available for use by transmission customers. Such use also impacts the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data in order for each entity to determine the TTC and ATC values for its own transmission system. This data is also necessary so that one RTO can refuse transmission service, if it is determined that the reservation request under consideration—if implemented—may overload facilities in the adjacent RTO.

The NERC SDX System currently is used to exchange statuses of generators rated greater than 150 MW, outages of all interconnections and other transmission facilities operated at greater than 230 kV, and peak load forecasts. This system has the capability to house daily data for the next seven days, weekly data for the next month and monthly data for the next year. Since this tool is currently being used and is maintained by NERC, the parties to this discussion believe that it would be prudent to use existing tools and methods as much as practical to accomplish the needed data tasks and avoid duplication of effort to the extent possible. Therefore the participating RTOs have agreed to fully populate the SDX System and update the data in the SDX System on a daily basis.

Therefore, the following data must be exchanged for each RTO to adequately determine its own TTC and ATC values and determine the impact of a proposed transmission service request on adjacent systems. Appendix A contains the procedural details of this data exchange.

<u>Generation Outage Schedules from SDX</u>

The projected status of generation availability over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that this data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete generation maintenance schedules are reflected in this data exchange. The RTOs have agreed that the 'return date' of a generator—either from a scheduled or forced outage— is necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the generator availability data provided to the other RTOs will be the most current data available. If the status of a particular generator of less than 150 MW is used within an RTO's TTC/ATC calculation, the status of this unit shall also be supplied via the NERC SDX System.

Generation Dispatch Order

In addition to the availability status of each 'significant' generator in a neighboring RTO, the dispatch of the available generation is necessary to accurately model future transmission system conditions. Broad assumptions can be made concerning generation, such as scaling all available generation to meet the generation commitments within an area and then increasing all generation uniformly to model an export, or similarly uniformly decreasing all generation to model an energy import. Excluding nuclear generation or hydro units from this scaling would provide some level of refinement. It was agreed that this simplistic approach may not be adequate to identify transmission constraints and determine rational TTC/ATC values. On the other extreme, economic data could be shared to allow an economic dispatch to be determined for each level of generation commitment. It was recognized that this level of refinement was generally unnecessary, and the data will likely be considered confidential by the generation owners, and therefore unavailable. As a practical alternative, each RTO will provide each neighboring RTO a typical generation dispatch order or generation participation factors of all units on a control area basis. With this information, combined with the availability of the units as provided by the SDX System, a reasonably accurate dispatch can be developed as necessary for any modeled condition. The generation dispatch order would be updated as required by changes in unit statuses; however, it is envisioned that a new generation dispatch order would not be necessary more often than prior to each peak load season.

Transmission Outage Schedules from SDX

The projected status of transmission outage schedules over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that these data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete transmission facility maintenance schedules are reflected in this data exchange. The RTOs have agreed that the 'outage date' and 'return date' of a transmission facility (either from a scheduled or forced outage) are necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the available data provided to the other RTOs will be the most current data available. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC of an RTO, the status of this facility would also be supplied via the NERC SDX System.

Transmission Interchange Schedules and Reservations

Schedules

The existing transmission reservations and interchange schedules of each neighboring RTO are also required to accurately determine the TTC and ATC values. Since interchange schedules impact the short-term use of the transmission system, the interchange schedules are necessary to determine the remaining capacity of the transmission system as well as determine the net impact of others' activities on the operation of each RTO. The resultant 'loop flow' has a direct impact on the amount of transmission service that can be accommodated by a transmission system. The parties have agreed that the interchange schedules will be made available to neighboring RTOs for their use. Because of the shear volume of this data, it may be more practical to post these data to a FTP site for downloading by neighboring RTOs as required by their own process and schedules. As an alternative, the parties have considered requesting NERC to modify the IDC to allow for selected interrogation by the RTOs. The actual method used to accomplish this data exchange will be determined in future discussions.

Reservations

Beyond the operating horizon, the impacts of existing transmission reservations are also necessary for the calculation of TTC and ATC for future time periods. The actual transmission reservation information will be exchanged among the RTOs for integration into their own TTC/ATC determination process. This information will also be made available via an FTP site. However, since a transmission reservation is a 'right to use' not an obligation to use the transmission system, the certainty of any particular reservation resulting in a corresponding interchange schedule is open to some level of speculation. This is especially true considering that the pro forma tariff allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, as yet, purchased all transmission reservations on a particular source-to-sink path. Further complicating this dilemma is that the duration or firmness of the 'second half' of the reservation may not be the same as the 'first half'. Therefore, since the portions of a source to sink reservation may not be able to be associated, prior to scheduling, double counting in the ATC determination process is a possibility. Therefore, information exchange regarding transmission reservations is necessary; however, the reservations themselves may not be incorporated into transmission models of the neighboring RTO. Each RTO will develop practices for modeling reservations, including external reservations, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. The procedures developed and implemented by each RTO to model intra-RTO reservations, reservations on external RTOs, and reservation netting practices will be shared with all adjoining RTOs.

Each RTO should also create and maintain a list of reservations from their OASIS that should not be considered in ATC calculations. Reasons for these exceptions may include grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched intra-RTO partial path reservations. If the RTO does not include it in its own evaluation, it should be excluded in other RTOs' analysis.

- Load Data

Peak load data for the period (e.g. daily, weekly and monthly) will continue to be provided via the NERC SDX System. Since, by definition, peak load values may only apply to one hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next 7-day horizon, it was agreed to either: supply hourly load forecasts OR daily peak load forecasts with a load profile. All load forecasts would be provided on a Control Area basis.

- Calculated Firm and Non-firm Available Flowgate Capability (AFC)

The Available Flowgate Capability (AFC) is the applicable rating of the Flowgate less the projected loading across the particular flowgate less Transmission Reliability Margin and Capacity Benefits Margin. The Firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, while the non-firm AFC is determined with both firm and non-firm reservations (or interchange schedules) modeled. Each RTO will accept or reject transmission service requests based upon projected loadings on their own flowgates as well as the loadings on 'foreign' flowgates, this data is required to determine if a transmission service reservation (or interchange schedule) will impact flowgates to an extent greater than the (firm or non-firm) AFC. Therefore, the Firm and Non-firm AFC for all relevant flowgates will be exchanged among the RTOs. Each RTO will also limit approvals of Transmission Service Requests so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the RTOs.

- Available Flowgate Rating

The Available Flowgate Rating is the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the flowgate. The flowgate rating is in units of megawatts. If the flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions. The RTOs will provide the neighboring RTOs with (seasonal, normal and emergency) ratings as well as the limiting condition (thermal, voltage, or stability). This information will be updated as required by changes on the system, but these ratings are currently fairly static values and do not currently require frequent updating.

- Identification of Flowgates

Flowgates that may initiate a TLR event must be considered in the RTO's TTC and ATC determination process. Foreign Flowgates that have a response factor equal to or greater than the distribution factor cut-off must be included in the evaluating RTO's model, as practical.

- Configuration/facility changes (for EMS model updates)

Transmission configuration changes and generation additions (or retirements) are normally communicated via the NERC MMWG process. The short term TTC/ATC determination processes are (will be) based upon an EMS model of the transmission system. Since frequently comparing the MMWG cases with the RTO's EMS models would be a significant, if not impractical task, a mechanism must be instituted to ensure that all significant system changes of a neighbor are incorporated in each RTO EMS model. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the 'major' changes that should be included in the EMS based Models in a more timely manner. This type of data change would be similar to the 'New Facilities' Listings usually included in Interregional reports; however, explicit modeling information would need to be supplied along with the listing. It is envisioned that this data exchange should occur no less often than prior to each peak load season. In addition, the RTOs agree to exchange EMS models of their transmission systems as mechanisms can be established to facilitate this exchange.

II. Procedures

The three RTOs participating in this seams effort have agreed to ATC coordination procedures designed to minimize the likelihood of over-reserving or over-scheduling of the transmission system. The procedures call for exchanging information that enables each RTO to identify the effects of system conditions in adjoining RTOs on their own flowgates. These procedures also call for exchanging flowgate AFCs with adjoining RTOs to recognize limits on foreign flowgates as well as their own flowgates as each RTO accepts Transmission Service reservations and/or schedules that transmission service.

These procedures describe the process for exchanging near-term planning information and AFCs. Each RTO will have its own internal procedures for incorporating information provided by the adjoining RTOs in their power flow models and utilizing foreign flowgate information when granting and scheduling transmission service. How these internal procedures work are not part of the coordination procedures. Each RTO can use different internal procedures and still accomplish acceptable coordination.

The following sections describe the ATC coordination procedures each RTO will follow. The ATC coordination procedure will be integrated by the RTOs into their own internal procedures for creating power flow models for determining AFCs. The ATC coordination procedures can be divided into two distinct activities: 1) calculation and posting of AFCs and 2) granting and scheduling transmission service. Individual descriptions of each activity are detailed below. However, these two activities are inter-dependent. (See figures 1 and 2)

- <u>Calculating and Posting ATCs</u>

Coordination of ATCs requires that system conditions in neighboring RTOs will be recognized and included when calculating AFCs. Therefore, each RTO will use AFCs for foreign flowgates when evaluating transmission service requests. A flow diagram of the process that the RTOs will follow for calculating and posting ATCs is included in Figure1. The flow diagram describes AFC determination. AFC values can be converted to Control Area (CA) to Control Area ATC values by dividing the most limiting flowgate AFC by its response factor.
The process was developed based on the following assumptions:

- Each RTO will develop its own set of flowgates and their applicable ratings and margins. Adjoining RTOs will acknowledge foreign flowgate limitations to the extent the owning RTO operates to its own flowgate limitations.
- Power flow models will be developed on a periodic basis to calculate AFC using information available via the data exchange from adjoining RTOs.

- AFCs are to be updated (i.e. decrement AFC using response factors and reservations) on a continuous basis but no less frequently than:
    - Once an hour for hourly and daily AFCs
    - Once a day for monthly AFC
- Each RTO will determine the response factors for local and foreign flowgates for use by the individual RTO.
- Each RTO will post CA-to-CA ATC and/or flowgate AFC for both their own flowgates and adjoining RTO flowgates. This allows transmission customers to view postings that may impact their ability to obtain transmission service
- Each RTO will compare adjoining RTO flowgate AFCs they calculate with the AFC exchanged by the RTO responsible for the flowgate for similar time periods and types of service (in the case of ARTO, the AFCs used to develop posted ATC will be used). Where significant differences are caused by factors other than the recognition of different transmission services sold by each RTO, the RTOs will, either individually or on a joint basis, take steps to improve the AFC calculation process.
- Each RTO will update their own flowgate AFCs on the data exchange. The data exchange update should be done at the same time the OASIS postings are updated to assure consistency in the data used by others. The participating RTOs will post these data no less often than once per hour or more often if necessary.
- An RTO will use the foreign flowgate AFCs provided via the data exchange in their respective ATC determination processes. If valid (i.e. 'fresh') foreign AFC values are not available from an RTO, the calculating RTO will default to use the local RTO's current AFC value for the foreign flowgates.
- The participating RTOs have agreed to monitor their processes and shorten the periodicity if they find overselling of transmission service or underutilization of the transmission system is occurring. (Note: The periodicity that is used to post AFC on the data exchange and the periodicity used by the participating RTOs accessing and utilizing foreign flowgate information in the ATC determination process is an ATC coordination issue. This time lag represents the amount of time each RTO continues to do business without recognizing recent commitments of other RTOs). .
- All participating RTOs shall use the response factor cut-off that the owning/operating RTO uses for their flowgate in their ATC determination efforts.

The sequence for calculating and posting AFCs is summarized below. Refer to Figures 1 and 2.

1. Each RTO will have its own periodicity for calculating (i.e. full network analysis) and updating AFCs. A RTO may have several periodicities depending on the service being offered (i.e., hourly AFC for the first 7 days may be updated once an hour, daily AFC for days 8 through 31 may be updated once a day and monthly AFC for months 2 through 13 may be updated once a week).

2. Each RTO will utilize data from the data exchange and the SDX as inputs to model development. These power flow models will also reflect system conditions in adjoining RTOs.
3. The power flow models will provide flowgate base flows used to determine AFC and will be used to calculate response factors for CA-to-CA transactions.
4. Before utilizing calculated AFCs from the power flow models, a check will be made whether it is a foreign flowgate. If it is a foreign flowgate, the AFC value from the data exchange will be used unless the time stamp indicates the data exchange supplied data is 'aged'. If the foreign RTO data is aged then the AFC from the power flow model is used.
5. If it is a local RTO flowgate, AFC from the power flow model is used for posting on OASIS and sent to the data exchange for use by other RTOs.
6. A continuous function is shown on Figure 1 that checks for changes in AFC on all posted flowgates. If the flowgate is a foreign flowgate, no action is taken. If the flowgate is a local flowgate and has changed, the changed AFC is posted on the data exchange. This is intended to capture the effects of periodic calculations of AFC and the effects of changes to AFC when transmission service is granted.

- Granting and Scheduling Transmission Service

Coordination of ATC values is involved in the granting of transmission service in that service should not be sold if it results in projected loading on a flowgate that exceeds the flowgate operating security limits. A general flow diagram of the process that the RTOs will follow when granting transmission service is in Figure 2. The process was developed based on the following assumptions:

- It is assumed a request for transmission service will be refused if AFC is not available. A request will not be refused if there are alternatives that can be used to create AFC (bumping lower priority service, offering higher price for same priority service, customer initiated redispatch, etc.).
- The RTOs are updating flowgate AFCs as transmission service requests are accepted.
- A check will be made of all foreign flowgates that are impacted by the pending transmission service request to ensure that they have been updated in the data exchange.
- Response factors for all flowgates are calculated by each RTO.
- This process assumes that other mechanisms are in place to ensure that partial path issues that may result in inadvertent double counting the same transmission service is addressed. These are coordination details that need to be addressed.
- This process addresses only limitations that can be quantified or equated to thermal limits. Other reviews such as voltage, stability and network analysis may be required before granting the service.

The sequence for granting and scheduling transmission service is summarized below.

1. When a request is received, the set of response factors for the specific source and sink will be checked for impacts on foreign flowgates. If there are no foreign flowgates with impacts, the request will be processed without further consideration of foreign impacts.
2. If a transmission service request impacts a foreign flowgate by equal to or greater than the response factor cut-off, the process is to check whether there has been a recent update of the foreign AFC via the data exchange. If the data exchange has been updated the foreign AFC will be decremented accordingly.
3. If the data exchange has not been updated, the process will decrement the RTOs own calculated AFC of the foreign flowgate.
4. This process is repeated for all impacted flowgates. If all flowgate AFCs remain positive after decrementing, the request is approved and its impact will be included in the next OASIS update.
5. If the request results in a projected flowgate loading exceeding its operating limits, then the request should be denied and the OASIS postings remain unchanged.
6. As described in Calculating and Posting ATCs section, once the evaluating RTO OASIS is updated with AFC changes, these changes will be posted on the data exchange for the RTO’s own flowgates. The newly approved reservation will be available to adjoining RTOs as they calculate their own flowgate AFCs.

Use of Schedules Not Reservations for Horizons where Schedules Exist

Schedules should replace reservations in the power flow model being used to determine AFCs. This may result in additional transmission capacity being available if the schedule is less than the reservation or if the schedule is creating a counter-flow to a constraint.

III. Other Issues

As part of the Inter-regional ATC coordination there are certain rights and responsibilities that are agreed to be reserved for the owning RTO. These rights include the sole determination of the AFC value to be honored by participating RTO's. The TRM and CBM values for each flowgate will be determined by the owning RTO.

The modeling of transmission reservations for determination of AFC within each participating RTO remains a concern. Problems with partial path reservations, inadequate tag information, and accuracy in predicting actual energy flow are issues that every RTO must address. The balance between over or under utilization of the transmission system resides with the decision on which transactions to model in determining remaining AFC. As described previously, each participating RTO will share data on transactions and flowgate impacts of modeled transactions. It will be each RTOs responsibility to determine which reservations and schedules are to be incorporated in their model to determine AFC values for the period in question. Each RTO will commit to standardizing this process as much as practical within RTO operating guidelines.

The congestion management plan that each RTO implements may affect the coordination process for determining inter-regional transfer capability. A reexamination of the treatment of foreign flowgates may be necessary depending on the congestion management plans.

ARTO/MISO/SPP
Flowgate Information Exchange Process

The following types of data will be exchanged among the RTOs for the purpose of setting up more accurate network modeling cases, determining the impact of other's transmission service sales on internal flowgates, and for the purpose of honoring external flowgates when selling transmission service.

Reservation Information – Transmission Service sold will be used by each RTO in determining the impact on internal flowgates of service sold by the other RTOs.

Scheduling Information – Used for the same purpose as reservation information, except in the scheduling time frame.

Flowgate Ratings and Available Capability – When determining whether to accept a new transmission reservation, each RTO will honor the AFC values calculated by the RTO that "owns" the flowgate.

System Information such as loads, equipment outages, generator availability and generation dispatch order.

Transmission Reservations

1. Transmission reservations that are in confirmed, accepted, or study mode will be exchanged via a file that contains all Transmission Reservations made on the RTO system for a minimum of 13 months and beyond this as necessary.

2. Transmission reservation data will be exchanged via two types of files, a base file and an update file.

3. The base file will be updated once a day and will contain all reservations on the RTO system for a minimum of 13 months and beyond this as necessary. This file should be generated and sent by 2330 each day.

4. Within each day, a file will be generated every hour which contains the new reservations in either confirmed, accepted, or study status within the last hour. The time that this file will be sent will be determined at a later date.

5. All files generated will have as the first record, the date and time the data was last updated. All dates and times will be in GMT or as mutually agreed.

6. Each RTO will use the reservations contained in these files for calculating base flow information.

7. The data to be included in the reservation file is as follows: OASIS number, Transmission Provider, Start Time, Stop Time, MW sold (All segments), Priority, Source/Sink. All times shall be in GMT or as mutually agreed.

Scheduling Information

1. Schedules will be exchanged via a file that contains all schedules for the current and next day.

2. The data to be included in the schedule file is as follows: Tag #, OASIS number(s), Transmission Provider, Start Time, Stop Time, MW schedule, Source/Sink. All times shall be in GMT or as mutually agreed.

3. Schedule Files will be updated as new schedules come in.

Flowgate Ratings and Available Capability

1. Total Flowgate Capability (TFC) and Available Flowgate Capability (AFC) information will be exchanged via a file that contains this data for a RTOs flowgates for a minimum of 13 months and beyond this as necessary.

2. TFC and AFC data will be exchanged via two types of files, a base file and an update file.

3. The base file will be updated once a day and will contain all TFCs and AFCs on the RTO system for a minimum of 13 months and beyond this as necessary. This file should be generated and sent by 2330 each day.

4. The update file will be continuously updated during the day as new transmission reservations are accepted, confirmed, or placed in study mode. This will be done at the same time as the OASIS posting is made.

5. Once flowgate values are received, decisions to sell service will be made using internally calculated response factors on the external flowgates.

6. This file will be considered old when it is not updated as follows: 1 hour for either hourly or daily AFCs, 1 day for monthly AFCs.

System Information

1. The NERC SDX System is the vehicle to exchange system information.

2. SDX data will be updated at least daily for all time horizons through month 13.

3. Load Data will supplied as follows: Daily peak forecasts (for 30 days) and monthly peak load forecasts for months 2 through 13. For the next 7 day horizon, hourly load forecasts OR daily peak load forecasts with a load profile will be provided. All of the above load forecasts would be on a Control Areas basis.

4. Transmission outages (including critical lower capability facilities), forced outages and return dates, and generation availability will be provided.

5. Generation dispatch order will be exchanged to determine appropriate generation dispatch for various scenarios.

ARTO/MISO/SPP
AFC Rating and AFC File Format

Each Filename would have the name: RTONAME_flowgateinfo

The format of the file is as follows:

1. The first record of the file should contain the date and time the data was calculated in the following format: mm/dd/yyyy xx:xx:xx

2. Each Record of the file following the first record should indicate flowgate ratings and values as follows:

- The first letter of each record indicate the time of the flowgate record as follows:
  - Y = Year, M = Month, D = Day, and H = Hour

- The second letter of each record indicates whether the record is a firm or a non-firm record type with F meaning Firm and N meaning Non-Firm

- Following these two record type indications would be entries indicating the timeframe of the values given in the record, the flowgate name, the Total Flowgate Capacity (TFC) for each period (with TRM and CBM already excluded), and Available Flowgate Capacity (AFC) for each period.

An example for each time frame is as follows:

YF, yyyy-yyyy, flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,, AFCX
MF, mm/yyyy-mm/yyyy, flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
MN, mm/yyyy-mm/yyyy, flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
DF, mm/dd/yyyy-mm/dd/yyyy, flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
DN, mm/dd/yyyy-mm/dd/yyyy, flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
HN, mm/dd/yyyy/hh-mm/dd/yyyy/hh, flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX

Where:
All Dates and Times are in CST
yyyy = year
mm = month (1=Jan, … 12=December)
dd = Day of the month
hh = Hour of the day (Hour Ending 1 through Hour Ending 24)

ARTO/MISO/SPP
Partial-Path ATC Methodology Proposal
April 30, 2001

I. Background

The Alliance RTO (ARTO), Midwest Independent System Operator (MISO), and Southwest Power Pool (SPP) have filed or plan to file to become FERC recognized RTO's. To fulfill this function, FERC requires that the RTO must ensure the integration of reliability practices within an interconnection and market interface practices among regions. The integration of market interface practices among regions includes the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures. The RTO is required to develop mechanisms to coordinate their activities with other RTOs. While it is not required to include the mechanisms at the time of RTO application, reporting requirements must be proposed by the RTO to provide follow-up details for how the RTO is meeting the coordination requirements.

Representatives of ARTO, MISO, and SPP, hereafter known as ARMISP, have been involved in a collaborative process to detail the data exchange requirements and mechanisms, data usage principles, and coordination of methodologies necessary to calculate coordinated TTC and ATC values across flowgates for a seamless market interface across the ARTO, MISO, and SPP borders. As part of the TTC and ATC calculations, this document describes the agreements reached by the three RTOs to facilitate fulfillment of available flowgate capability (AFC) coordination related to partial-path reservations made to accommodate transactions that cross RTO boundaries. It does not address intra RTO reservations that are partial path between individual transmission providers/control areas prior to the formation of the RTO.

II. Recent Activity

The ARMISP team has worked through a collaborative effort in developing fundamentals for coordination. One of the key issues for ARMISP, as well as the industry as a whole, has been partial-path reservations. Partial-path reservations are reservations on a single transmission provider that will require complementing reservations on adjacent transmission providers to complete the intended source to sink path. These partial path reservations are often requested from the transmission providers at different times with differing priority and durations. This practice has caused difficulty in assessing transmission requests by the transmission providers. In some instances the partial-path requests have caused double counting of reservations that will ultimately be used as a single schedule. This has resulted in a reduced ATC for transmission customers and reduced transmission revenues for transmission owners.

ARMISP has developed a collaborative partial-path methodology to accommodate these transmission reservations that affect the three RTO's while maintaining reliability.

III. Partial-Path Analysis Methodology

The objective of these principles is to provide a mechanism to evaluate Flowgate limits within the evaluating RTO and RTOs not on the source to sink path at the time of evaluation. The following principles apply to reservation requests that are made on any of the ARMISP OASIS systems:

Each RTO is responsible for evaluating transmission requests made on its own OASIS. For requests that have the source and sink within a single RTO, the RTO shall consider AFC on all flowgates including those of neighboring RTOs. For a transmission request made on an RTO's OASIS, which has a source/sink and/or POR/POD in the external RTOs, the evaluating RTO shall consider AFC on all flowgates including those of neighboring RTOs except those of any RTO that is a required party to complete the source to sink path identified in the reservation request.
Each RTO is responsible for evaluating the impact of a request on all flowgates of the transmission providers not on the source to sink path.

When a transaction crosses several RTO's appropriate reservations must be made on each RTO in series within the source to sink path. This proposed process recognizes this fact and provides a mechanism to avoid double counting and thereby result in more accurate AFC's. This partial-path methodology provides for reasonable AFC determination accuracy on flowgates by including reservation impacts from other RTO's.

These basic principles are explained further by illustrative examples. Four examples show how the methodology is implemented within the participating RTO's. The examples are sourced in SPP, but the same principles apply regardless of which RTO is the source.

Example 1: SPP to MISO

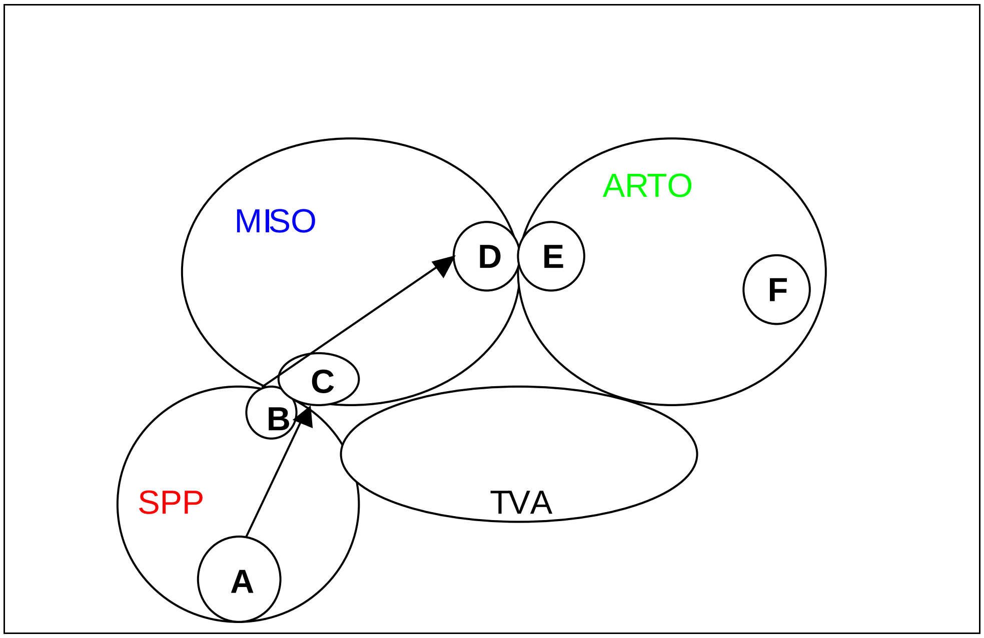


Figure 1: SPP to MISO Reservation

The reservation on SPP is an A to C transmission request. This reservation allows a transmission user to move energy from a location within SPP to SPP's inter-ties with the MISO at C. The initial reservation is made on the SPP OASIS followed by a later reservation completing the path on the MISO OASIS. When the MISO receives a corresponding reservation request, it will be from B to D with a stated source of A and sink of D. The table below shows the reservations requested on each system.

ARTO				MISO				SPP			
POR	POD	Source	Sink	POR	POD	Source	Sink	POR	POD	Source	Sink
-	-	-	-	B	D	A	D	A	C	A	C

SPP would evaluate the request from A to C as requested, excluding the MISO flowgates from SPP's evaluation but including TVA and ARTO. (Note: AFCs for all affected flowgates, including MISO flowgates, in the SPP model would be decremented based on that transmission request. The reason AFCs for MISO flowgates are adjusted is to mitigate the possibility that a second unrelated reservation on SPP could result in an over-subscription on the MISO flowgates.) Once the corresponding request is received by the MISO, MISO would evaluate it on the source and sink information contained in the MISO request. However in the MISO evaluation, all SPP flowgates would be excluded from the MISO evaluation.

The SPP flowgates are evaluated on the initial reservation information and the MISO would evaluate the corresponding reservation request with the information provided on the MISO reservation.

Example 2: SPP to ARTO through MISO

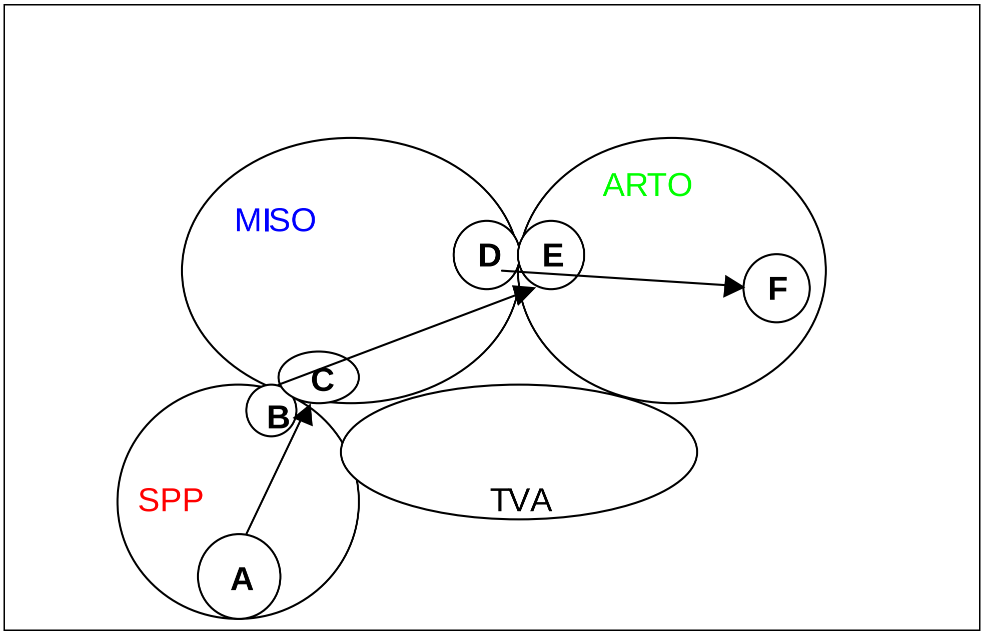


Figure 2: SPP to ARTO through MISO

This example illustrates a request made first on SPP, followed by a request on the MISO and then a request on the ARTO to complete the source to sink path. Three requests are made at different times to illustrate putting a deal together which encompasses three RTO's. The following table shows the detail of each respective request.

ARTO				MISO				SPP			
POR	POD	Source	Sink	POR	POD	Source	Sink	POR	POD	Source	Sink
D	F	A	F	B	E	A	E	A	C	A	C

For the first request received by SPP, the evaluation would not consider the MISO flowgates; but would consider all other flowgates including those in TVA (and other external systems) and the ARTO. Next, the request is received by the MISO and evaluated. These impacts would be very similar to the example one request shown above. The MISO would not consider either the SPP or ARTO flowgates since both SPP and ARTO are part of the source to sink path. The MISO would consider flowgates in TVA and other external systems. The ARTO finally gets the full path for evaluation. However since both the SPP and MISO are on the source to sink path, only ARTO flowgates and non-ARMISP flowgates are evaluated.

Example 3: SPP to ARTO through TVA

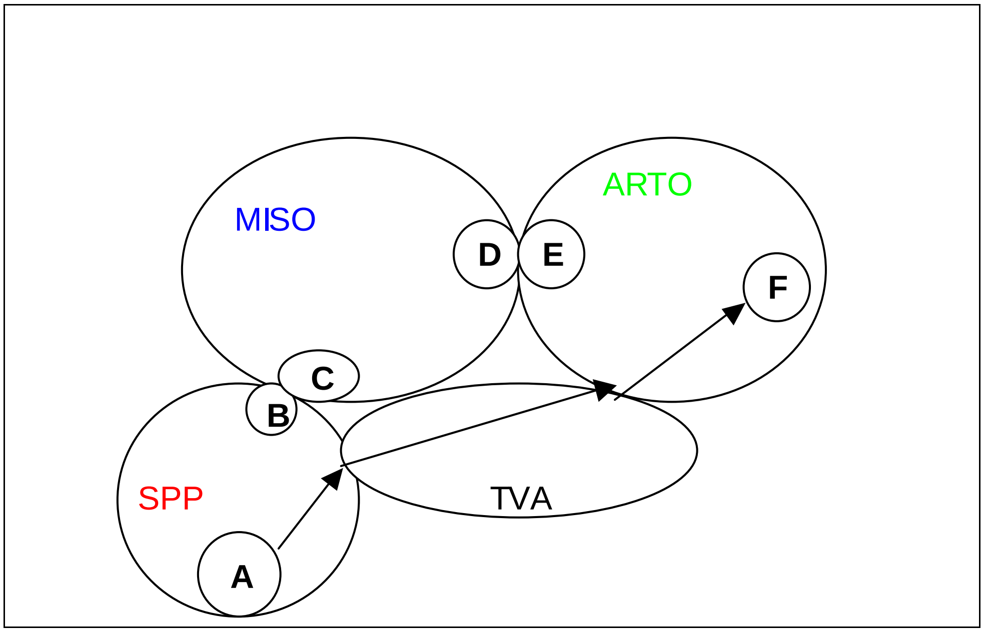


Figure 3: SPP to ARTO through TVA

This example illustrates how a reservation made on a parallel path will be evaluated. Similar to example 2, the request is sourced in SPP and sinks in ARTO. However, this request is routed through TVA instead of the MISO. The actual flows will be exactly the same as example 2, however the transmission reservations are different. The table below lists the transmission reservations.

ARTO				MISO				SPP			
POR	POD	Source	Sink	POR	POD	Source	Sink	POR	POD	Source	Sink
TVA	F	A	F	-	-	-	-	A	TVA	A	TVA

For the first request received by SPP, the evaluation would consider the MISO, ARTO and all relevant external flowgates, except TVA since TVA is in the source to sink path. Next, TVA receives and evaluates the request. The ARTO receives a request and, because the import is from a non-participant, evaluates the AFC on all flowgates, except TVA and SPP which are on the source to sink path.

Example 4: Market Risk for Delayed submittal of all Partial Path Requests

This example demonstrates how non-simultaneous submittal of all legs of a transaction requiring service on more than one RTO can result in a customer having a partial path reservation it cannot use. To avoid the situation, the Transmission Service Customer should consider making all associated requests involving multiple RTOs simultaneously.

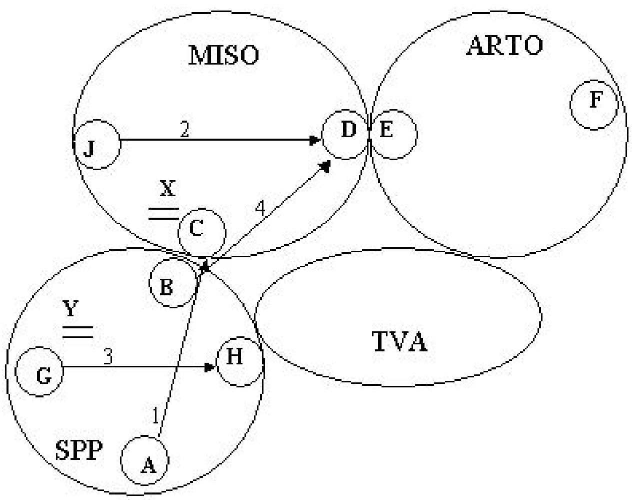
Initial Conditions

Flowgate X AFC posted by MISO = 45 MW

Flowgate Y AFC posted by SPP = 100 MW

Sensitivity from A – C on X = 0.30
Sensitivity from G – H on X = 0.15
Sensitivity from A – D on X = 0.15
Sensitivity from J – D on X = 0.30

Sensitivity from A – C on Y = 0.20
Sensitivity from G – H on Y = 0.30
Sensitivity from A – D on Y = 0.15
Sensitivity from J – D on Y = 0.10



Request #1 – Partial Path on SPP 100 MW

ARTO				**MISO**				**SPP**			
POR	POD	Source	Sink	POR	POD	Source	Sink	POR	POD	Source	Sink
-	-	-	-	-	-	-	-	A	C	A	C

This request is identical to that shown in example 1. SPP will evaluate this request exactly the same. There were no TVA or ARTO flowgates affected. SPP will decrement AFC on Flowgate Y by 20 MW. Flowgate Y is O.K. Flowgate X is decremented by 30 and is also O.K. SPP would ignore the result on the MISO flowgate even if it had been negative since the request was going to MISO. MISO will evaluate affects on its flowgates when the corresponding request is made on their system.

Since Flowgate Y is an SPP flowgate, SPP posts a revised Y AFC of 80 MW on the data exchange. Since Flowgate X is a MISO flowgate, SPP does not post a revised X AFC on the data exchange. However, SPP does post the approved request for use by other RTOs. SPP will continue to use its own internal calculation of the remaining capacity on Flowgate X until MISO changes the data exchange value posted for Flowgate X.

Request #2 – Unrelated Complete Path request received on MISO 100 MW

ARTO				MISO				SPP			
POR	POD	Source	Sink	POR	POD	Source	Sink	POR	POD	Source	Sink
-	-	-	-	J	D	J	D	-	-	-	-

This request was received by the MISO system. As described in the Coordination of ATC document, MISO determines Flowgates X and Y have response factors that meet the threshold requirements. MISO also determines Flowgate Y is a foreign flowgate belonging to SPP. MISO queries the data exchange and finds Flowgate Y has 80 MW AFC posted. MISO also sees the partial path reservation sold by SPP on the data exchange. MISO does not decrement Flowgate X for the partial path reservation sold by SPP because a reservation is required on the MISO OASIS to complete the path and no reservation has been submitted. Using data from the data exchange and its own internal flowgate calculation, MISO will decrement AFC on Flowgate X by 30 MW (from 45 MW to 15 MW) and decrements Flowgate Y by 10 MW (from 80 MW to 70 MW) but no violation has occurred. MISO must honor both MISO and foreign flowgates since this request is internal to MISO. Again, it is assumed that this transfer affected no ARTO or TVA flowgates.

MISO will post a revised Flowgate X AFC of 15 MW on the data exchange. MISO does not post a revised Flowgate Y on the data exchange. However, MISO does post the approved request for use by other RTOs.

Request #3 – Unrelated Complete Path request on SPP 100 MW

ARTO				MISO				SPP			
POR	POD	Source	Sink	POR	POD	Source	Sink	POR	POD	Source	Sink
-	-	-	-	-	-	-	-	G	H	G	H

This request was received by the SPP system. As described in the Coordination of ATC document, SPP determines Flowgates X and Y have response factors that meet the threshold requirement. SPP also determines flowgate X is a foreign flowgate belonging to MISO. Based on its own internal calculation, SPP has a remaining Flowgate X AFC of 15 MW. However, SPP also sees MISO has recently changed its X AFC posted on the data exchange so SPP will use the more recent MISO posted Flowgate X AFC of 15 MW. SPP also sees the 100 MW reservation posted by MISO is located entirely within MISO. SPP will decrement its Y AFC by 10 MW (from 80 MW to 70 MW to recognize the service sold by MISO. Using information from the data exchange and its own internal flowgate calculation, SPP will decrement AFC on Flowgate X by 15 MW (from 15 MW to 0 MW) and will decrement AFC on flowgate Y by 30 MW (from 70 MW to 40 MW). The MISO flowgate X was at 15 MW AFC, exactly enough AFC to provide this service. Flowgate Y has a resulting positive AFC of 40 MW. Therefore this request is approved also.

SPP will post a revised Y AFC of 40 MW on the data exchange. SPP does not post a revised Flowgate X AFC on the data exchange. However, SPP does post the approved request for use by other RTOs.

Request #4 – Partial Path on MISO to complete Request #1

ARTO				**MISO**				**SPP**			
POR	POD	Source	Sink	POR	POD	Source	Sink	POR	POD	Source	Sink
-	-	-	-	B	D	A	D	-	-	-	-

This request is identical to the second request of Example 1 made on the MISO OASIS. MISO determines Flowgates X and Y have response factors that meet the threshold. MISO also determines Flowgate Y is a foreign flowgate belonging to SPP. Based on its own internal calculation, MISO has a remaining Flowgate Y AFC of 70 MW. However, MISO also sees SPP has recently changed its Y AFC posted on the data exchange so MISO will use the more recent SPP posted Flowgate Y AFC of 40 MW. MISO also sees the 100 MW reservation entirely located within SPP. MISO will decrement its Flowgate X AFC by 15 MW (from 15 MW to 0 MW) to recognize the service sold by SPP. Using information from the data exchange and its own internal flowgate calculation, MISO will decrement AFC on Flowgate X by 15 MW (from 0 MW to –15 MW). Since the AFC on flowgate X has already gone to 0, MISO would refuse this request since it has a 15% response on the flowgate.

V. Observations

The following is a list of outstanding issues which need to be recognized by each RTO in establishing internal practices to determine ATC values.

1. **Designated and Undesignated Resources:** This procedure assumes that for all power transfers between RTOs that an OASIS reservation will exist on each RTO's OASIS for the segment of the source to sink path within each RTO. This includes imports for serving native load from designated and undesignated resources.
2. Grandfathered Transmission Service: Each grandfathered service must be explicitly addressed (i.e. via an OASIS reservation) in the determination of ATC.
3. **ATC 'Accuracy':** Ideally, every transmission reservation request would have the ultimate source and sink known at the time of the request which would result in more accurate ATC values. However, this is not practical under the current marketing business practices in place. This methodology does not guarantee that TLR's will not occur! TLR's may still be caused by parallel flows through neighboring systems that have no transmission service on the ARMISP. Additionally, as partial-paths are combined a small change in flow could occur on the actual completed path compared with the initially

reserved path causing TLR's. However, this methodology does provide a way to minimize the potential impacts of partial path reservations which could lead to TLR conditions.

Attachment B
Screening Reservations Used to Determine AFC

As MISO Carmel and MISO St. Paul begin exchanging reservations and as the Alliance Companies, MISO and SPP implement the interim ATC coordination process that includes exchanging reservations, there needs to be a screening of those reservations to remove duplicates that will be received when reading reservations from ftp sites of different transmission providers. In addition to duplicates, there needs to be a screening-out of partial path reservations whereby transmission service may have been bought from one transmission provider but not another. Where one transmission provider has sold the service and another transmission provider has not, the transmission provider that has not sold the service should exclude those reservations from its analysis. Otherwise, a customer would only need to buy service from one transmission provider and then have service along the entire path locked up.

Because of differences in how transmission service is sold between Alliance Companies, MISO and SPP, there will be different screening sets depending on which reservations are being read. The Alliance Companies have sold service along contract paths where multiple reservations exist and a reservation may or may not exist on the sink transmission provider OASIS node. The MISO and SPP, on the other hand have sold or will sell service on a regional basis that does not result in multiple reservations if the transaction stays within the footprint of the transmission provider. There also needs to be recognition that MAPP Schedule F will be treated as grandfathered transmission service by MISO and does not get converted to MISO service on February 1. This mean MISO will develop four screening sets (MISO Carmel reads MISO St. Paul reservations, MISO St. Paul reads MISO Carmel reservations, MISO Carmel/St. Paul reads SPP reservations and MISO Carmel/St. Paul reads ECAR/MAIN reservations). The rules for each of the screening sets are given below.

There are basic assumptions that went into development of the screening sets. If one of the basic assumptions is wrong or changes, the screening sets must be reviewed for impacts. The basic assumptions are:

- With the exception of MAPP Schedule F, all transmission service that has been arranged by MISO TOs either gets converted to MISO transmission service and appears on the MISO OASIS page or has been copied from the TO OASIS page on its regional OASIS node to a TO OASIS page on the MISO OASIS node by February 1. This means that starting on February 1, reservations for MISO TOs should come from the MISO OASIS node and not from one of the regional OASIS nodes.

- Prior to February 1, duplicate reservations are being entered on the regional OASIS nodes and the MISO OASIS node. The customers were told they must have their duplicate reservations entered on both the MISO OASIS node and the regional OASIS nodes by January 15. This delay in entering duplicate reservations allowed the customers to continue making requests on regional OASIS nodes until they got their MISO customer registration information completed. Starting on January 15, the MISO OASIS node will contain all reservations that involve MISO TOs and there is no need to read reservations on the regional OASIS nodes for MISO TOs. This means all reservation for service starting after February 1 or starting prior to February 1 but continuing after February 1 will be on the MISO OASIS, which establishes its place in the queue.

- MAPP Schedule F transmission service is grandfathered under the MISO tariff. This means that MAPP Schedule F service that involves MISO CAs in MAPP can be sold up until midnight on January 31. This MAPP Schedule F service does not get converted to MISO service. For MAPP Schedule F service sold prior to February 1, the MAPP OASIS node will be the only node that contains these reservations. There is no duplicate reservation on the MISO OASIS node.

- MAPP Schedule F transmission service that is sold on or after February 1 will only involve the non-MISO CAs. Where there is no connection between two non-MISO CAs in MAPP, they will either need MISO transmission service to complete the path or will use grandfathered transmission service to complete the path. In either case, MISO will have the new service or will have the grandfathered service on its OASIS node. MISO will only consider new MAPP Schedule F service sold on or after February 1 if it is between two directly connected non-MISO CAs.

- MISO offers both PTP service and NITS. Customers with network service will submit OASIS requests for designated and undesignated network resources. MISO will treat these as equivalent to firm and non-firm PTP transmission service requests as it calculates AFCs.

- Getting Alliance Company reservations from the ECAR and MAIN ftp sites is a temporary arrangement until Alliance Companies either join MISO or make arrangements to become part of another RTO. MISO is assuming there will be no Alliance RTO unless FERC reverse its decision. This means MISO is not anticipating a need to coordinate transmission service through an ARTO ftp site.

- For reservations placed on the ECAR, MAIN, MAPP and SPP ftp sites, the POR/POD, source/sink, and transmission service type are specific to the transmission provider that sold the service. MISO has developed a mapping table to convert these items to a format that can be used by MISO OASIS Automation. The rule sets to screen reservations are designed to be implemented after the reservations have been converted to a MISO format.

A generic rule set will be applied to all regional postings of reservations on ftp sites. Specific rules will then be developed for each region based on this generic rule set.

Generic Rule Set

1. MISO will always include transmission service that is on the MISO OASIS node. This means the screening set will be designed to ignore transmission service with other transmission providers that forms the remainder of the path with the MISO service.

2. The Alliance Companies, MISO and SPP have agreed in the ATC Coordination document to exchange both reservations on their OASIS nodes and a list of excluded reservations. MISO Carmel, MISO St. Paul and SPP will have exclude lists as part of their initial implementation. ECAR and MAIN do not have exclude lists. Where an exclude list exists, these reservations will be removed before the screening is made.

3. MISO will include MISO requests that have a status of study, accepted and confirmed in its AFC calculation. However, it will only include confirmed requests from other transmission providers.

4. If MISO can tell that transmission service sold by another transmission provider also has MISO transmission service, MISO will ignore the service sold by the other transmission provider. Examples of this are instances where either the source or the sink are a MISO CA or if neither the source nor the sink is a MISO CA but the customer has used a MISO interface in the POR/POD to indicate the service involves MISO. The only exception to this is MAPP Schedule F sold prior to February 1. It is grandfathered under the MISO tariff and will be kept even if the source and/or sink is a MISO CA.

5. MISO has a number of CAs that are non-contiguous. The only way to complete the path will be through an Alliance Company. The transmission service sold by the Alliance Company looks like a wheel with both the source and the sink being MISO CAs. Consistent with 4 above, the Alliance Company services will be ignored because MISO will have the request or it is a partial path where service has not been requested from MISO yet.

6. For service between two non-MISO CAs where MISO is getting reservations from both transmission providers (i.e. AMRN to AEP) MISO will always keep the source reservation and will throw away the sink reservation. We cannot be certain that sinks will always have an OASIS reservation because the sink may consider the import to be use of its network service tariff and does not require an OAIS request. Therefore, we always default to using the source reservation.

7. For service between two non-MISO CAs where MISO is only getting reservations from one of the transmission providers (i.e. PJM to AEP), MISO will keep the service if they are either the source or the sink.

8. If a non-MISO transmission provider has sold a wheel (the source CA and sink CA are not part of the transmission provider) and MISO is getting reservations from either

the source CA or the sink CA (i.e. AMRN sold AEP to EES and MISO is getting AEP reservations), MISO will throw away the wheel reservation.

9. If a non-MISO transmission provider has sold a wheel and MISO is not getting reservations from either the source CA or the sink CA (i.e. AEP sold PJM to TVA), MISO will keep the wheel reservation.

10. MISO Carmel will provide reservations on its ftp site from both the MISO OASIS page and the TO OASIS pages (contains grandfathered service that is not converted to MISO service). To avoid double counting, MISO St. Paul should only post on its ftp site MAPP Schedule F transmission service and transmission service sold my non-MISO CAs. As an alternative to restricting its posting, MISO St. Paul can post an exclude list that removes transmission service on the MAPP OASIS that is also on the MISO OASIS. SPP will post transmission reservations from both the SPP page and from the SPP control area pages. To avoid double counting, SPP needs to remove MPS and WPEK reservations from the set they post. They can either exclude them from their posting or they can include them in the posting and add them to the exclude reservation list. MISO will only read reservations on the ECAR and MAIN ftp sites where Alliance Companies are the transmission providers. This means that MISO will screen-out all reservations on the ECAR and MAIN ftp sites where the transmission provider is not an Alliance Company. MISO still must decide how it will get reservations from other transmission providers that are not part of the coordination effort.

Screening Rules when MISO Carmel Reads MISO St. Paul

- Use exclude list to remove reservations from MISO TOs on MAPP OASIS.

- Map the remaining reservations to MISO POR/POD, source/sink, type of service.

- For MAPP Schedule F service sold prior to February 1, include the service in the MISO review set.

- For MAPP Schedule F service sold on or after February 1, only include transmission service between two non-MISO CAs that are directly connected.

- The only remaining reservations on the St. Paul ftp site should be transmission service sold by the non-MISO CAs in MAPP. The non-MISO CA rules applies to this set. Starting on February 1, MAPP Schedule F will only provide up to 6 consecutive months of service that must be reserved no earlier than 120 days in advance of the start date. All other service will be arranged through the non-MISO CA tariffs and will appear on the CA OASIS pages.

Screening Rules when MISO St. Paul Reads MISO Carmel

- MISO St. Paul needs reservations from MISO Carmel that affect MAPP flowgates and that are not on the MAPP OASIS. If we assume grandfathered service that has been moved to the MISO OASIS node has been annulled on the MAPP OASIS, St. Paul will read-in all MISO transmission service on the MISO OASIS page and on the TO OASIS page on the MISO node by reading the MISO Carmel ftp site. If we cannot assume the grandfathered service has been annulled on the MAPP OASIS, the potential for double counting transmission service sold prior to February 1 exists. One alternative is to have MISO St. Paul create an exclude list which would exclude MISO reservations that are on both the MISO Carmel and MISO St. Paul OASIS nodes.

- MISO St. Paul will read the ECAR, MAIN and SPP nodes the same as MISO Carmel and does not require a special screening.

Screening Rules when MISO Reads SPP

- SPP has a regional tariff similar to MISO. This means that reservations where SPP is the transmission provider that stay totally within the SPP footprint only have a single reservation. The only screening that is needed is when the service goes outside SPP and involves one of the Alliance Companies, a MAPP CA or a MISO CA. If it has a source/sink that is a MISO CA or has a POR/POD that uses a MISO interface, it will be ignored because of the MISO rule to always include its own service. If it has a source/sink that is an Alliance Company or has a source/sink that is a non-MISO CA in MAPP, the rules on non-MISO CAs apply.

- There can be a small number of SPP transmission service that was sold by the SPP CAs separate from the regional tariff. We do not expect a significant amount of this service. If it exists, it could appear on multiple OASIS pages and the non-MISO CA rules apply.

Screening Rules when MISO Reads ECAR/MAIN

- An initial screen must be made to only read reservations where an Alliance Company is the transmission provider.

- There is no exclude list being exchanged with the ECAR and MAIN information. MISO will check whether the Alliance Companies are willing to provide excluded reservations separately from reading the ECAR and MAIN ftp sites.

- The non-MISO CA rules apply. We need to identify which Alliance Companies have reservations on the regional ftp sites that MISO will read. We will then set the rules for these Alliance Companies to indicate we are reading their reservations as non-MISO CAs.

- We may still have a timing issue in that we are only getting reservations either once a day (MAIN) or four times during the day (ECAR). MISO will check whether the Alliance Companies are willing to post their reservations to the ftp sites more frequently.

NPCC CO-13 Whitepaper on Regional Methodology and Guidelines for Forecasting TTC and ATC

NPCC CO-13
Available Transfer Capability Working Group
September 20, 2005

Table of Contents

1. Summary

This document establishes a common NPCC methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC).

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, and the Canadian provinces of Ontario, Québec and the Maritimes.

NPCC consists of five Control Areas[1] on the northeastern portion of the NERC Eastern Interconnection. Because of NPCC's geographic location, only the New York and Ontario Control Areas experience parallel flows. The remaining Control Areas, the Maritimes, Québec 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, Québec, and New England Control 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.

All five NPCC Control Areas are currently posting ATC values, however physical transmission service for reservation on their OASIS nodes is currently only offered by the Maritimes, Québec and select Transmission Providers in New England for service over the following interfaces Phase I/II (HQ-NE), Cross Sound Cable (NY-NE) and the MEPCO System (NB-NE). New Brunswick Power is the only Transmission Provider within the Maritimes Control Area that has external ties to other Control Areas. However, Nova Scotia and New Brunswick have separate Transmission Tariffs and are registered with NERC as separate Balancing Authorities, so ATC is calculated for the Nova Scotia – New Brunswick interface.

All transmission paths posted in the NPCC Region are flowgate based and there are no parallel fractional postings of flowgate values by different entities.

Within NPCC there presently exists two types of ATC, one in the market-based systems (New England, New York and Ontario) and one in the physical reservation based systems

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[1] The North American Electric Reliability Council (NERC) has been updating its reliability functions to unbundle the reliability functions that control areas have traditionally performed. Accordingly, NERC has developed a Functional Model to enable it to rewrite its reliability standards in terms of the responsible entity which now performs a given reliability function. In particular, with regard to the balancing function, a Balancing Authority is identified under NERC's Functional Model as having the responsibility to maintain the load-resource balance within a Balancing Authority Area. A Balancing Authority Area, in turn, is defined as the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. Balancing Authorities came into effect on April 1, 2005.

This document uses the term Control Area (capitalized) to refer to the five traditional Control Areas as define in the NPCC A-07 document.

(Québec and the Maritimes). The market-based systems publish forecast ATC in the operations horizon, based on the possible utilization of the system, as an indication of what may be available in the particular market.

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. New York and New England have FERC approved tariffs. Québec, Nova Scotia[2] and New Brunswick Power have established transmission tariffs based on FERC Order 888. Although the Ontario transmission tariff is not based on the FERC model, FERC has determined that it meets the principles of non-discriminatory transmission access[3].

There are essentially two types of transmission open access:

- Via physical reservations for transmission service, for the sake of a physical bilateral market. Those holding the reservations have the right to use the transmission to schedule their trade in the physical market.
- Via access to the dispatch in an energy market. Trades that clear the market automatically get transmission access. Participants in the energy market can buy financial rights that insure them from additional congestion costs.

Québec, Nova Scotia and New Brunswick post 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 operate electricity markets where energy is scheduled based on offers and bids, and access to the transmission system is automatic upon "clearing" the market (that is, 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 and the types of transmission service in each Area can be found in Section 10.

[2] The Nova Scotia Open Access Transmission Tariff was approved by the Nova Scotia Utility and Review Board on May 31, 2005 for full implementation before November 1, 2005.

[3] In a recent case (Ontario Energy Trading Corp., supra, 103 FERC 61,044 April 11, 2003, petition for review filed June 10, 2003, D.C. Circuit), FERC approved Ontario Energy Trading Corporation's power marketing authorization despite the fact that the Ontario Independent Market Operator did not have an Order 888 tariff. FERC noted that the IMO Tariff provided transmission service on a non-discriminatory basis; did not impede Ontario Energy Trading's competitors from reaching United States loads; and provided a service that was comparable to Order 888 point-to-point service for through-and-out service.

3. Objective of the NPCC Methodology

3.1. Common Methodology

This document establishes a common NPCC methodology for calculating TTC and ATC that complies with non-discriminatory open access principle, the NERC definitions for TTC and ATC, the NERC Reliability Standards MOD-001-0 through MOD-009-0, and NPCC Document A2 *Basic Criteria for Design and Operation of Interconnected Power Systems*.

3.2. Allowance for both Physical Transmission Reservations and Energy Market Systems

In recognition of physical transmission reservation systems in support of bilateral markets, and energy markets using financial congestion management, that have both 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 reasonably 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.

This methodology will also be consistent with NERC’s Reliability Standards

3.4. NPCC TTC/ATC Principles

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

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

1. Calculation and posting of TTC and ATC 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 Balancing Authorities, 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 Balancing Authorities, the definition of the interfaces (flowgates) 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 method, necessary data, and posting procedures will be made available to adjoining systems in other regions and sub-regions. Interregional coordination of ATC calculation and posting must recognize regional differences in the market structures.

7. Known operating conditions external to a Control Area (such as generation or transmission outages) that cause an operating limit violation within the Control Area must be reflected in TTC/ATC calculations. External operating conditions that do not cause operating violation within a Control Area are not reflected in TTC/ATC calculations. Reservations conducted external to a Control Area will not be considered for TTC/ATC calculations within the Control Area.

3.5. NPCC TTC/ATC Webpage

The NPCC TTC/ATC Webpage has provided the marketplace a single location to show ATC and TTC values across registered paths between Control Areas within and between adjoining Areas to NPCC. The link to the site is: http://www.nerro.org

4. TTC Forecasting – Components and Assumptions

4.1. Path requirements

All Balancing Authorities within NPCC that offer Open Access Transmission Services must define the transmission paths for which they allow energy transfers in to, out of, and through their systems. A transmission path is defined by the Point of Delivery (POD), where the energy is delivered to an adjacent system, and the Point of Reception (POR) where the energy is received from an adjacent system.

FERC Order 889 (Code of Federal Regulations Title 18, Section 37.6(b)) requires ATC and TTC for all Posted Paths to be calculated and posted on OASIS. A Posted Path is defined as "…any control area to control area interconnection; any path for which service is denied, curtailed or interrupted for more than 24 hours in the past 12 months; and any path for which a customer requests to have ATC or TTC posted."

Each Posted Path should be identified by its POR and POD. The POR and POD can be physical points on 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 Posted Path consisting of the aggregation of segments connected in series, the resulting TTC will be the minimum of the series segments. *And similarly, resulting ATC will be the minimum of the series segments ATC values.*

Connectivity of the Posted Paths through the overall network should use consistent POR/POD naming when applied to the same physical interconnection or interface. Appendix A lists Posted Paths in use in NPCC.

4.2 Determination of TTC

The TTC across a transmission Path is the pre-contingency level of power that can be transferred over said Path in such a way that following the most severe contingency of the network, system security (thermal, voltage and stability limits) is maintained in concordance with NPCC design and operating criteria as well as rules and practices adopted by the affected systems and Control Areas. The TTC on a transmission Path is direction specific and is evaluated along its whole path.

The following should be considered when determining TTC:

- System Conditions - the base case for the period being analyzed must consider projected customer demands, generation dispatch, system configuration, and scheduled transfers.
- Severe Contingencies - the most restrictive contingencies must be analyzed.
- System Limits - Impact analysis of the most severe 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 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:
- Radial Path, where the limiting element is within the path
- Non Radial Path, where the limiting element may be outside the path or parallel flows may reduce ATC.

In the case of an interconnection between adjacent Control Areas comprising radial connection to generation and/or load at one end, the individual respective TTC will reflect the minimum of the following:
- The transmission capability (thermal, voltage or stability)
- The installed generation capacity at the sending end in the case of radial connection to generation
- The maximum forecasted load at the receiving end in the case of radial connection to load
- The maximum amount of net load or net generation across the Path.

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 is defined as the total resulting power flow on the interface when a pre-contingency or post-contingency limitation (whichever is more limiting) 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.

In many cases, system conditions on a local system can impact TTC between Control Areas in ways that are not captured by joint operating studies. These conditions might arise in the operating horizon due to generation, load or transmission conditions. The resulting TTC will be provided to the NPCC web site by the party that recognizes the impact of these conditions, which can result in a different TTC value for the same path by each of the Control Areas that post the path. It is the responsibility of the transmission customer to recognize that, if there is an apparent discrepancy between the various TTC values posted on the NPCC web site, the minimum TTC is the ruling value.

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 future forecasts. Forecasts are provided on:

- An hourly basis for up to the next 168 hours;
- A daily basis for up to the next 30 days (excluding the first 7 days, which are provide hourly as above);
- A monthly basis for the current month and the 12 months next following;
- A yearly basis for up to 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.

Forecasted TTCs are defined according to the anticipated operating conditions that have an impact on operating limits within the Control Area the transmission Path belongs to.

Forecasted 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
- 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 shall be done to meet the specified timelines for the following classes of TTC:

- Before 15:00, hourly values for the next operating day at least once per day
- Hourly values for the current operating day to reflect real time conditions
- Daily values for the current week at least once per day.
- Daily values for day 8 through the first month at least once per week.
- Monthly values for months 2 through 13 at least once per month.

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 systems, TTCs will reflect the load and generation main characteristics such as installed generation capacity and maximum forecasted load.

TTCs posting requirements are as follows:

- TTCs posted yearly will be based on the maximum TTC for the year
- TTCs posted monthly will be based on the maximum daily TTC for the month
- TTCs posted daily will correspond to the minimum TTC for the day
- TTCs posted hourly will correspond to the minimum TTC for the hour.

For TTC calculations that are affected by radial loads, the forecasted seasonal or long-term peak value can be used.

For TTCs that are affected by radial generation, TTC calculation should reflect the installed generation capacity.

5. ATC Forecasting – Components and Assumptions

5.1. Determination of ATC in a Physical Market

Essentially, ATC is the amount of transmission service available for use by the electric power market. There are different ways to access the transmission system

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 (TRM), less the sum of existing transmission commitments (including native and firm and non-firm load) 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". See Section 3.3 above.

The process for determining ATC must also comply with the relevant NPCC principles contained in Section 3.4 above.

5.1.1. Accounting for 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[4] and non-firm ATC[5] 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) - 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 – schedule with firm Transmission Service[6]

[4] Also referred to as non recallable (NATC)
[5] Also referred to as recallable (RATC)
[6] Firm Transmission Service is not offered on an hourly basis, so the use of Firm ATC in the operating horizon is dependent on local market rules.

Non-Firm ATC = TTC - b(TRM) -net schedule (firm/non-firm, forward/reverse)

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

5.1.2. Recognition of Points of Injection and Withdrawal

Due to the nature of the power systems and the market practices within NPCC, ultimate 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, or equivalent.

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.

5.1.3. 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

5.1.4. Allowances for Varying Demand and how ATC assumptions vary with time

The uncertainties of varying customer demand are reflected in ATC through TRM calculations (see Section 7).

5.1.5. 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.

NATCs posting requirements are as follows:
- NATCs posted yearly will be available 95 % of the year
- NATCs posted monthly will be available 95 % of the month
- NATCs posted daily will correspond to the minimum ATC for the day

RATCs posting requirements are as follows:
- RATCs posted yearly will be based on the maximum RATC of the year
- RATCs posted monthly will be based on the maximum daily RATC for the month
- RATCs posted daily will correspond to the maximum RATC for the day
- RATCs posted hourly will correspond to the minimum RATC for the hour.

5.1.6. Netting of Transmission Reservations or Schedules

- 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 schedules are not netted for forecasting firm ATC.

5.2 ATC Determination in the Energy Markets

For energy markets, transmission access is obtained via the market dispatch, not by granting physical service via ATC posting. Transmission system availability may be published to provide information to market participants to assist them in moving energy between adjacent markets. This information may be of such form as transmission availability according to the market bids or according to the market resolution. Note that in an energy market, a zero or negative ATC value does not mean that no one else can participate, it indicates that there may be congestion, and congestion costs could be incurred to transfer energy over the path. See Appendix B for individual market calculations of posted 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 or 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.

Generation reliability requirements will be reviewed on a regular basis at least annually consistent with NPCC criteria

6.2. Calculation

If CBM is used, it must be calculated for:

a) The long-term planning period, according to the Resource Adequacy assessment requirements of *Basic Criteria for Design and Operation of Interconnected Power Systems* (NPCC Document A-2, Section 3.0) and *Guidelines for Area Review of Resource Adequacy* (NPCC Document B-8). The methodology used to derive CBM must be documented and consistent with published Transmission Provider and NPCC planning criteria.

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 a Load Serving Entity (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.

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).

The 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. 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 that 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. When new TRM values are used, the transmission providers must notify the markets (publish a notice) that new values are in effect. TRM values and methodology must be made available to NPCC, NERC, and transmission users in the electricity market, within 30 days of a request.

7.4. Intra-NPCC TRM

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

7.5. Interregional TRM

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, Québec 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 Québec, 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 Québec, 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 Québec 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 Québec. In some cases where load or generation is physically switched from one 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 Nova Scotia, New Brunswick, New England, Québec 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 Facilities Notification List. 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. Inter and Intraregional data coordination

NPCC members participate in the following information exchange processes that will be used for the ATC and TTC forecasting. Information provided by other regions is utilized by NPCC members in the process for calculation of ATC and TTC. This information is used to determine the impact of external conditions on internal and control area to control area transfer capabilities. When such an impact has been identified, the ATC and TTC will reflect the external conditions as per agreements.

- NPCC annually participates in providing load flow models to the NERC Multiregional 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 NPCC Facilities Notification List is exchanged on a regular basis to notify the affected Control Areas, as documented in NPCC Procedure C-13, "*Operational Planning Coordination*". In addition, weekly conference calls are conducted to provide updates on conditions that could affect neighbouring Control Areas.

- NPCC Areas synchronously connected participate in the NERC System Data Exchange (SDX) and must update their information at least once daily, and as frequently as hourly if conditions on their system warrant an update. "The SDX is the NERC approved method for the submittal of operational planning horizon data that is required in NERC Policy 9 Subsection A – Next Day Operations Planning Process, Requirement 1. This data is shared throughout the interconnection(s) for use in ATC calculations and the NERC TLR application, the Interchange Distribution Calculator (IDC) and power system studies. The data is required to be submitted hourly for each Control Area and received by the SDX system by 20 minutes prior to the reporting hour. Updates to these data may be submitted more frequently."[7]

- Transaction Information System (electronic tagging) provides all the short-term transactions information.

[7] Updated language from the NERC Reliability Coordinator Reference Document dated March 25, 2004.

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 post 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.

NPCC's TTC/ATC web page includes the co-ordinated TTC values, and forecast ATC values on each of the NPCC control area to control area paths, uploaded from the OASIS or web page of each individual NPCC Control Area. The NPCC web page shows, for each control area to control area path, a side-by-side comparison of each Area's TTC and ATC values.

9.2 Interregional Coordination

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 that 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 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 MISO for ECAR and MAPP regions.

MISO utilizes a market based system and is the transmission provider for the ECAR and MAPP regions bordering NPCC. MISO posts TTC values, receives requests for transmission service, and grants transmission access. The ATC and TTC values for the NPCC to MISO ties are determined by the respective transmission owners under MISO; IESO determines the ATC and TTC values for the Ontario ties based on facility ratings and any other restrictions identified by the Hydro One (the relevant transmission owner in Ontario). IESO will use ATC and TTC values from its calculations to forecast the Ontario transfer capability.

MISO will use the TTC developed by the transmission owners in MISO, and will check these against the Ontario ATC and TTC before transmission access is granted in MISO.

MISO to IESO hourly schedules will respect the most restrictive transfer capability.

The IESO and MISO are currently working on an operating agreement that will clearly delineate roles responsibilities between the IESO and MISO and its internal control areas and transmission owners.

9.2.3 Coordination of Interdependent TTCs

Currently, there is a multi-dependent relationship among the Québec to New England transfer, Québec 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 - IESO

10.1.1. Market Information

In the Ontario market, the IESO administers access to the market, in place of physical reservations for access. The following transmission owners have transmitter licences:

- Hydro One, one of the successor companies to Ontario Hydro, holding the majority of transmission assets in Ontario,
- Canadian Niagara 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,
- Five Nations Energy Inc., supplying Moosonee in the northeast,
- Cat Lake Power Utility Ltd., supplying part of the northwest,
- Niagara West Transformation Corporation, supplying part of the Niagara region in southern Ontario.

The Ontario market is an electricity market allowing participants to buy and sell energy via bilateral contracts and an energy spot market. The schedules for injection are determined from sellers' minimum offer prices to sell quantities of electricity, while schedules to withdraw energy are 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 is calculated from the selected bids and offers. This price is applied to all participants inside Ontario. Participants outside Ontario, who are offering or bidding to the Ontario market across control area ties, are 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 IESO 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 uses a hybrid method of congestion management. All participants outside of Ontario who inject or withdraw via an external tie line are 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 is 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 is based on the second dispatch, and the additional re-dispatch costs are charged to all market participants as a congestion management charge.

Internal to Ontario, generation and dispatchable load are sent a dispatch instruction every five minutes. In recognition of hourly scheduling of control ties, the Ontario control area ties are scheduled on an hourly basis, and their schedules are then fixed for the hour, unless transmission reliability dictates a curtailment. The dispatches are selected on the basis of price in the hour-ahead time frame. Compensation is provided for transactions to protect against real-time price variations contrary to their bids and offers, e.g. an energy offer that clears in the hour ahead time frame will be guaranteed the minimum of its offer or the market clearing price, if the 5-minute price were to drop below the hour-ahead pre-dispatch price estimate. Congestion costs would be added in the event of congestion.

10.1.4 ATC in the Market System

Because access to the market is via the dispatch, the IESO does not offer transmission service independent of its dispatch and does not grant requests for reservations of physical transmission access. Therefore, the IESO does not operate an Open Access Same-Time Information System (OASIS). Market information and specifically forecasts and results of its dispatch process, is posted on the IESO public web site. Confidential information specific to individual market participants is provided via participant-specific reports.

In the IESO energy market, transactions, generation, and dispatchable loads are given access to the dispatch based on their energy bids and offers. Once they clear the market they all get equal access to the transmission system. Since transmission service will be granted automatically to any transaction that clears the market, all service will have the same priority. Therefore there is no need to calculate both recallable and non-recallable ATC. The IESO posts the same value for both recallable and non-recallable ATC.

The IESO uses its Dispatch Scheduling and Optimization (DSO) tool to produce its advisory dispatches for the day-ahead period (first published at 11:00 am for the following day) up to one hour in advance of real-time. The pre-dispatch scheduling limits used for the DSO are posted as the ATC and some TTC values.

For more information on how ATC/TTC is calculated by the IESO, reference the IESO ATC/TTC Methodology.

10.1.5 Ontario OASIS Node

Because access to the Ontario market is via dispatch, the IESO does not offer transmission service independent of its dispatch, and does not grant requests for reservations of physical transmission access. Therefore the IESO does not operate an OASIS. Market information, including ATC, is posted on the IESO public web site:
http://www.ieso.ca/imoweb/marketdata/marketData.asp.

10.2. New York ISO

10.2.1 Market Information

The NYISO has been designated as the Transmission Provider for transmission service in the NY Control Area by the eight transmission owners in New York and is responsible for coordinated operation between the NY utilities and neighboring 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 and 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. RTC 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 resources that were provided schedules and the accepted transactions are defined as the Transmission Interface Flow Utilization, resulting from the day-ahead and real time 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 constrained unit 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 assigned 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 Real Time Commitment (RTC) and Real Time Dispatch (RTD) programs for real time operation. The NYISO is dispatched in real time, using accepted bids and transactions supplied to the Real Time 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 their 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.

10.2.4 ATC in the Market System

ATCs 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.

10.2.5 New York OASIS Node

ATC/TTC is posted on the NY ISO public web site at:
http://www.nyiso.com/public/market_data/power_grid_data.jsp

10.3. ISO New England

10.3.1 Market Information

Within ISO New England there are 12 transmission providers and one Merchant Transmission Facility (MTF). They are:

<u>TRANSMISSION PROVIDERS</u>

- Bangor Hydro Electric Company (BHE)
- Central Maine Power Company (CMP)
- Central Vermont Public Service Company (CVPS)
- Citizen Utilities Company (CZN)
- Florida Power and Light (FPL)
- Green Mountain Power Company (GMP)
- Maine Electric Power Company (MEPCO)
- ISO New England (ISNE). Also know as the Pool Transmission Facilities
- 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)
- Unitil (UNITIL)
- Vermont Electric Company (VELC)

MERCHANT TRANSMISSION FACILITY:
- Cross Sound Cable (CSC)

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-Québec TransEnergie control area.

10.3.2 Transmission Access

There are two types of Open Access for transmission services available in the New England Control Area: financial transmission under the ISO New England markets and the Physical transmission under the traditional Pro Forma Reservation System.

Services under ISO New England Markets
The implementation of the ISO New England markets on March 1st 2003 has changed the calculation, posting and use of ATC values on the ISNE Node.

Under ISNE market rules, there are no advanced transmission reservations required for external transactions over the ISNE facilities known as Pool Transmission Facilities (PTF). External energy is scheduled economically based on offers and bids within the market, and transmission service is automatically granted to those offers and bids that are scheduled to flow at the beginning of the scheduling hour.

Requests for external energy schedules are not restricted by the ATC value at the time of submittal. The posted ATC is simply calculated based on the MW amount of accepted offers and bids submitted to the market and serves as an indicator of the requested utilization of the external interfaces.

Physical Based Transmission Service
The other Transmission Providers within New England will continue offering advanced reservations for Pro Forma transmission service under the traditional Physical Reservation System. Firm and non-Firm ATC will continue to be decremented by advance reservations and where appropriate TRM

10.3.3 Congestion Management

The overall objective of the ISO New England market design is to establish a common market framework that promotes greater economic efficiency and completion, promotes power system reliability and provides reasonable wholesale electricity prices. ISO New England provides Locational Marginal Prices in a Day Ahead Energy Market and a Real Time Energy Market, and offers financial hedging through the auction of Financial Transmission Rights.

Security constrained interface limits are developed and enforced for each hour in the Day Ahead Market and on an ongoing basis in Real-time Operations. Congestion over the external ties is managed by curtailment of transactions according to Market indicators and/or 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.

10.3.4 ATC in the Market System

ISNE does not require physical reservations for transmission service on the PTF; therefore, the designation of Firm and Non-firm to ATC in regard to the PTF is no longer appropriate. There is only a single value for ATC. Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM), parameters associated are not needed for the Market System and have zero MW value. ATC is used as an indicator of utilization of the interfaces. In the operational horizon, when market participants may have interest in an ATC value, the ATC is the related to the amount of energy transactions that have been submitted to the ISNE market system.

Negative ATC in the ISNE market-based system can be an indication of increased demand for transactions flowing in a particular direction. Since ATC will not limit the amount of transactions to be considered for scheduling there could be times when ATC indicates a substantially negative value. It must be recognized that a negative ATC should not discourage the submittal of a transactions, as the economic evaluation of these schedules will determine the actual energy flow in Real Time.

10.3.5 New England OASIS Node

http://nepool.jtsin.com/OASIS/NODE

10.4. Québec

10.4.1 Market information

Within Québec there are six transmission providers:

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

- McCormick (LCHM), which is interconnected with TÉ.

These Transmission Providers are not under FERC jurisdiction; however TÉ, CRT and Brascan provide Open Access to their system. TÉ operates an OASIS site that posts ATC for only TÉ and CRT.

10.4.2. Transmission Access

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

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.

10.4.4 Québec OASIS Node

The Hydro-Québec TransÉnergie OASIS site is located at:
http://www.transenergie.com/oasis/hqt/en/entree.htmlx

10.5. Maritimes

10.5.1. Market information

Within the Maritimes Area there are five transmission providers:
- NB Power, which is interconnected with NE, NSPI, TE, MECL, EMEC and MPSC. (http://www.nbpower.com/)
- Nova Scotia Power (NSPI), that is interconnected to NB Power only. (http://www.nspower.ca/)
- Maritime Electric (MECL), that is interconnected to NB Power only. (http://www.maritimeelectric.com/)
- Maine Public Service (MPS), that is interconnected to NB Power only. (http://www.mainepublicservice.com/)
- Eastern Maine Electric Cooperative (EMEC), that is interconnected to NB Power only. (http://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 fall under FERC jurisdiction.

On October 1, 2004, the independent crown corporation New Brunswick System Operator (NBSO) assumed the role of Operator of the NB transmission system and electricity market (http://www.nbso.ca/).

10.5.2. Transmission Access

NB Power is the only transmission provider in the Maritime area that has interconnections external to the Maritime area. Both NB Power/NBSO and NSPI have open access transmission tariffs based on FERC Order 888 *pro forma*. NB Power/NBSO offers access to its transmission system for eligible external customers (for through and out service), and eligible NB customers (municipal electric utilities and large industrial customers connected directly to the transmission system at 69kV and above). NSPI offers wholesale transmission access to municipal electric utilities as well as out service (through service is not possible due to the geographic location of NS).

The NS-NB interconnection is operated in the same manner as Control Area interconnections. Physical transmission reservations are taken for the NS-NB interconnection, requiring the calculation and posting of ATC and TTC on both the NS and NBSO OASIS systems. TTC and ATC for interconnections with other Control Areas are posted on the NBSO OASIS.

10.5.3. Congestion Management

Congestion on the interconnections between NB Power and neighbouring utilities is managed on a non-discriminatory base by NBSO. Congestion is managed by curtailment of transactions according to FERC and NERC principles and the NBSO 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.]

Congestion on the NSPI system is handled on a non-discriminatory basis as prescribed by the FERC *pro forma* tariff. Congestion on internal (non-posted) paths is handled by economic re-dispatch of generation, with out-of-merit dispatch costs shared among all transmission users according to their share of transmission usage at the time of the congestions. Congestion on the NS-NB interconnection is handled by curtailment of transactions on priority basis (firm over non-firm) or pro-rated over the same class of transmission service.

10.5.4 Maritimes Area OASIS Nodes

The NBSO OASIS node, for access to NB Power transmission system is located at http:/www.nbso.ca.

The NSPI OASIS node, for access to transmission in Nova Scotia, is located at http://oasis.nspower.ca/

Appendix A: Posted Paths in NPCC

Incoming paths on the ISNE OASIS	POR	POD
NE/ISNE/ISNE/ME ISNE INT-ISNE PTF/	ME ISNE INT	ISNE PTF
NE/ISNE/NYIS-ISNE/NY NE BORDER-ISNE PTF/	NY NE BORDER	ISNE PTF
NE/ISNE/HQT-ISNE/HQ_PHI_OR_II-ISNE PTF/	HQ_PHI_OR_II	ISNE PTF
NE/ISNE/HQT-ISNE/VTHVDCBORDER-ISNE PTF/	VTHVDCBORDER	ISNE PTF
NE/ISNE/NYIS-ISNE/LI CT CSC-ISNE PTF/	LI CT CSC	ISNE PTF
NE/ISNE/HQT-ISNE/NEHVDCBORDER-HQ_PHI_OR_II/NEU	NEHVDCBORDER	HQ_PHI_OR_II

Outgoing paths on the ISNE OASIS	POR	POD
NE/ISNE/ISNE-NYIS/ISNE PTF-NY NE BORDER/	ISNE PTF	NY NE BORDER
NE/ISNE/ISNE/ISNE PTF-ME ISNE INT/	ISNE PTF	ME ISNE INT
NE/ISNE/ISNE-HQT/ISNE PTF-HQ_PHI_OR_II/	ISNE PTF	HQ_PHI_OR_II
NE/ISNE/ISNE-HQT/ISNE PTF-VTHVDCBORDER/	ISNE PTF	VTHVDCBORDER
NE/ISNE/ISNE-NYIS/ISNE PTF-LI CT CSC/	ISNE PTF	LI CT CSC
NE/ISNE/ISNE-HQT/HQ_PHI_OR_II-NEHVDCBORDER/NEU	HQ_PHI_OR_II	NEHVDCBORDER

Through paths on the ISNE OASIS	POR	POD
NE/ISNE/HQT-NYIS/VTHVDCBORDER-NY NE BORDER/	VTHVDCBORDER	NY NE BORDER
NE/ISNE/HQT-ISNE/VTHVDCBORDER-ME ISNE INT/	VTHVDCBORDER	ME ISNE INT
NE/ISNE/HQT-NYIS/VTHVDCBORDER-LI CT CSC/	VTHVDCBORDER	LI CT CSC
NE/ISNE/HQT-NYIS/HQ_PHI_OR_II-NY NE BORDER/	HQ_PHI_OR_II	NY NE BORDER
NE/ISNE/HQT-NYIS/HQ_PHI_OR_II-LI CT CSC/	HQ_PHI_OR_II	LI CT CSC
NE/ISNE/HQT-ISNE/HQ_PHI_OR_II-ME ISNE INT/	HQ_PHI_OR_II	ME ISNE INT
NE/ISNE/NYIS-HQT/LI CT CSC-HQ_PHI_OR_II/	LI CT CSC	HQ_PHI_OR_II
NE/ISNE/NYIS-ISNE/LI CT CSC-ME ISNE INT/	LI CT CSC	ME ISNE INT
NE/ISNE/NYIS-NYIS/LI CT CSC-NY NE BORDER/	LI CT CSC	NY NE BORDER
NE/ISNE/NYIS-HQT/LI CT CSC-VTHVDCBORDER/	LI CT CSC	VTHVDCBORDER
NE/ISNE/ISNE-NYIS/ME ISNE INT-NY NE BORDER/	ME ISNE INT	NY NE BORDER
NE/ISNE/ISNE-NYIS/ME ISNE INT-LI CT CSC/	ME ISNE INT	LI CT CSC
NE/ISNE/ISNE-HQT/ME ISNE INT-HQ_PHI_OR_II/	ME ISNE INT	HQ_PHI_OR_II

NE/ISNE/ISNE-HQT/ME ISNE INT-VTHVDCBORDER/	ME ISNE INT	VTHVDCBORDER
NE/ISNE/NYIS-ISNE/NY NE BORDER-ME ISNE INT/	NY NE BORDER	ME ISNE INT
NE/ISNE/NYIS-HQT/NY NE BORDER-HQ_PHI_OR_II/	NY NE BORDER	HQ_PHI_OR_II
NE/ISNE/NYIS-HQT/NY NE BORDER-VTHVDCBORDER/	NY NE BORDER	VTHVDCBORDER
NE/ISNE/NYIS-NYIS/NY NE BORDER-LI CT CSC/	NY NE BORDER	LI CT CSC

Incoming paths on the HQTE OASIS	**POR**	**POD**
IMO/HQT/LAW-HQT	LAW	HQT
IMO/HQT/P33C-HQT	P33C	HQT
IMO/HQT/Q4C-HQT	Q4C	HQT
IMO/HQT/CHNO-HQT	CHNO	HQT
IMO/HQT/OTTO-HQT	OTTO	HQT
IMO/HQT/DYMO-HQT	DYMO	HQT
IMO/HQT/MAHO-MATI	MAHO	MATI
NYIS/HQT/CRT-HQT	CRT	HQT
NYIS/HQT/MASS-HQT	MASS	HQT
ISNE/HQT-HIGH-HQT	HIGH	HQT
ISNE/HQT/NE-HQT	NE	HQT
ISNE/HQT/DER-HQT	DER	HQT
NBPC/HQT/NB-HQT	NB	HQT

Outgoing paths on the HQ-TÉ OASIS	**POR**	**POD**
HQT/IMO/HQT-LAW	HQT	LAW
HQT/IMO/HQT-P33C	HQT	P33C
HQT/IMO/HQT-Q4C	HQT	Q4C
HQT/IMO/HQT-CHNO	HQT	CHNO
HQT/IMO/HQT-OTTO	HQT	OTTO
HQT/IMO/HQT-DYMO	HQT	DYMO
HQT/IMO/MATI-MAHO	MATI	MAHO
HQT/NYIS/HQT-CRT	HQT	CRT
HQT/NYIS/HQT-MASS	HQT	MASS
HQT/ISNE/HQT-HIGH	HQT	HIGH
HQT/ISNE/HQT-NE	HQT	NE
HQT/ISNE/HQT-DER	HQT	DER
HQT/NBPC/HQT-NB	HQT	NB

Internal paths on the HQTE OASIS	POR	POD
HQT/HQT/HQT-MATI	HQT	MATI
HQT/HQT/HQT-MAFA	HQT	MAFA
HQT/HQT/MATI-HQT	MATI	HQT
HQT/HQT/MAFA-HQT	MAFA	HQT

Incoming paths on NYISO OASIS	POR	POD
HQ-NYISO	HQ	NYISO
IMO-NYISO	IMO	NYISO
ISONE-NYISO	ISONE	NYISO
PJM-NYISO	PJM	NYISO
NPX-CSC	NPX-CSC	NYISO

Outgoing paths on NYISO OASIS	POR	POD
NYISO-HQ	NYISO	HQ
NYISO-IMO	NYISO	IMO
NYISO-ISONE	NYISO	ISONE
NYISO-PJM	NYISO	PJM
CSC-NPX	CSC-NPX	NYISO

Through service paths on NYISO OASIS	POR	POD
HQ-NYISO / NYISO-IMO	HQ	IMO
HQ-NYISO / NYISO-ISONE	HQ	ISONE
HQ-NYISO / NYISO-PJM	HQ	PJM
HQ-NYISO / CSC-NPX	HQ	CSC-NPX
IMO-NYISO / NYISO-HQ	IMO	HQ
IMO-NYISO / NYISO-ISONE	IMO	ISONE
IMO-NYISO / NYISO-PJM	IMO	PJM
IMO-NYISO / CSC-NPX	IMO	CSC-NPX
ISONE-NYISO / NYISO-HQ	ISONE	HQ
ISONE-NYISO / NYISO-IMO	ISONE	IMO
ISONE-NYISO / NYISO-PJM	ISONE	PJM
ISONE-NYISO / CSC-NPX	ISONE	CSC-NPX
PJM-NYISO / NYISO-HQ	PJM	HQ
PJM-NYISO / NYISO-IMO	PJM	IMO
PJM-NYISO / NYISO-ISONE	PJM	ISONE
PJM-NYISO / CSC-NPX	PJM	CSC-NPX
NPX-CSC / NYISO-HQ	NPX-CSC	HQ
NPX-CSC / NYISO-IMO	NPX-CSC	IMO

NPX-CSC / NYISO-ISONE	NPX-CSC	ISONE
NPX-CSC / NYISO-PJM	NPX-CSC	PJM

Incoming paths on NBSO OASIS	**POR**	**POD**
HQ-HVDC to EMEC	HQ-HVDC	EMEC
HQ-HVDC to MECL	HQ-HVDC	MECL
HQ-HVDC to NBPC	HQ-HVDC	NBPC
HQ-HVDC to MPS	HQ-HVDC	MPS
HQ-Radial to NBPC	HQ-RADIAL	NBPC
MEPCO to MECL	MEPCO	MECL
MEPCO to MPS	MEPCO	MPS
MEPCO to NBPC	MEPCO	NBPC

Outgoing paths on NBSO OASIS	**POR**	**POD**
EMEC to HQ-HVDC	EMEC	HQ-HVDC
MECL to HQ-HVDC	MECL	HQ-HVDC
NBPC to HQ-HVDC	NBPC	HQ-HVDC
MPS to HQ-HVDC	MPS	HQ-HVDC
NBPC to HQ-Radial	NBPC	HQ-RADIAL
MECL to MEPCO	MECL	MEPCO
MPS to MEPCO	MPS	MEPCO
NBPC to MEPCO	NBPC	MEPCO

Through service paths on NBSO OASIS	**POR**	**POD**
NSPI to HQ-HVDC	NSPI	HQ-HVDC
MEPCO to HQ-HVDC	MECL	HQ-HVDC
NSPI to MEPCO	NSPI	MEPCO
HQ-HVDC to MEPCO	MPS	MEPCO
HQ-HVDC to NSPI	HQ-HVDC	NSPI
HQ-HVDC to MEPCO	HQ-HVDC	MEPCO
MEPCO to NSPI	MEPCO	NSPI
MEPCO to HQ-HVDC	MEPCO	HQ-HVDC

Paths Listed on IESO OASIS

Path Name	POR	POD	Injection Zone	Withdrawal Zone	Path Description
MAN-ON	MHEB	IESO	Manitoba	Ontario	Manitoba to Ontario on Circuits K21W & K22W
MICH-ON	IESO	DECO	Michigan	Ontario	Michigan to Ontario
MIN-ON	MP	IESO	Minnesota	Ontario	Minnesota to Ontario
NY-ON	NYIS	IESO	New York	Ontario	New York to Ontario
ON-MAN	IESO	MHEB	Ontario	Manitoba	Ontario to Manitoba on Circuits K21W & K22W
ON-MICH	IESO	DECO	Ontario	Michigan	Ontario to Michigan
ON-MIN	IESO	MP	Ontario	Minnesota	Ontario to Minnesota
ON-NY	IESO	NYIS	Ontario	New York	Ontario to New York
ON-QBEAU	IESO	HQT	Ontario	PQ.B5D.B31L	Ontario to Québec on Circuits B5D & B31L
ON-QD4Z	IESO	HQT	Ontario	PQ.D4Z	Ontario to Québec on Circuit D4Z
ON-QD5A	IESO	HQT	Ontario	PQ.D5A	Ontario to Québec on Circuit D5A
ON-QH4Z	IESO	HQT	Ontario	PQ.H4Z	Ontario to Québec on Circuit H4Z
ON-QH9A	IESO	HQT	Ontario	PQ.H9A	Ontario to Québec on Circuit H9A
ON-QP33C	IESO	HQT	Ontario	PQ.P33C	Ontario to Québec on Circuit P33C
ON-QQ4C	IESO	HQT	Ontario	PQ.Q4C	Ontario to Québec on Circuit Q4C
ON-QX2Y	IESO	HQT	Ontario	PQ.X2Y	Ontario to Québec on Circuit X2Y
QBEAU-ON	HQT	IESO	PQ.B5D.B31L	Ontario	Québec to Ontario on Circuits B5D & B31L
QD4Z-ON	HQT	IESO	PQ.D4Z	Ontario	Québec to Ontario on Circuit D4Z
QD5A-ON	HQT	IESO	PQ.D5A	Ontario	Québec to Ontario on Circuit D5A
QH4Z-ON	HQT	IESO	PQ.H4Z	Ontario	Québec to Ontario on Circuit H4Z
QH9A-ON	HQT	IESO	PQ.H9A	Ontario	Québec to Ontario on Circuit H9A
QP33C-ON	HQT	IESO	PQ.P33C	Ontario	Québec to Ontario on Circuit P33C
QQ4C-ON	HQT	IESO	PQ.Q4C	Ontario	Québec to Ontario on Circuit Q4C
QX2Y-ON	HQT	IESO	PQ.X2Y	Ontario	Québec to Ontario on Circuit X2Y

Appendix B: Area Methodologies

Ontario Independent Electricity System Operator
ATC/TTC METHODOLOGY

June 6, 2005

INTRODUCTION

This document describes the methodology used by the Ontario Independent Electricity System Operator (IESO) to calculate Total Transfer Capability (TTC) and Available Transfer Capability (ATC).

MARKET INFORMATION

The IESO-administered electricity market in Ontario allows participants to buy and sell energy via bilateral contracts and an energy spot market. Access to the market is via the IESO dispatch, not via physical transmission reservations.

DEFINITIONS

ATC is defined by NERC as:

"A measure of transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin."

ATC = TTC - TRM - CBM - existing transmission commitments

TTC is defined by NERC as:

"The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions"

CBM is defined by NERC as:

"The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE 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 transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies."

TRM is defined by NERC as:

"The amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change."

To determine a TRM value, the following factors should be considered to account for uncertainties in systems conditions:

a) aggregate load forecast error
b) load distribution error
c) variations in facility loading
d) uncertainties in system topology
e) simultaneous transfers and parallel path flow
f) variations in generation dispatch
g) calculation inaccuracies
h) short-term operator response factor
i) short-term vs. long-term time frames

ATC/TTC DETERMINATION

In the IESO energy market, transactions, generation, and dispatchable loads are given access to the dispatch based on their energy bids and offers. Once they clear the market they all get equal access to the transmission system. Since transmission service will be granted automatically to any transaction that clears the market, all service will have the same priority. Therefore there is no need to calculate both recallable and non-recallable ATC. The IESO posts the same value for both recallable and non-recallable ATC.

Because access to the market is via the dispatch, the IESO does not offer transmission service independent of its dispatch and does not grant requests for reservations of physical transmission access. Therefore the IESO does not operate an Open Access Same-Time Information System (OASIS). Market information, and specifically forecasts and results of its dispatch process, is posted on the IESO public web site. Confidential information specific to individual market participants is provided via participant-specific reports.

The IESO uses its Dispatch Scheduling and Optimization (DSO) tool to produce its advisory dispatches for the day-ahead period (first published at 11:00 am for the following day) up to one hour in advance of real-time. The pre-dispatch scheduling limits used for the DSO are posted as the ATC and some TTC values.

The IESO uses TRM components (c), (d) and (e) from above for the ATC calculation on the Michigan, New York, Manitoba, Minnesota, and select Quebec interconnections. For the New York and Michigan interconnections, the parallel path flow component is applied to account for the Lake Erie circulation, and the variations in facility loading is applied to account for automatic generation control (AGC). The system topology uncertainties are applied to the Manitoba and Minnesota interconnections to account for deadband on the phase shifters. For the Quebec interconnections, system topology uncertainties are applied to account for operating margin on D4Z imports into Ontario; Beauharnois imports into Ontario; and H4Z exports out of Ontario. For the remaining Quebec interconnections TRM components are not used, therefore, the ATC value and TTC value are the same.

NEAR-TERM ASSESSMENTS AND REPORTS

If market participants require additional information with regard to IESO interconnections beyond the hourly time frame posted on the NPCC ATC/TTC webpage, participants can access additional information via IESO Security and Adequacy Assessment and/or System Status Reports (http://www.ieso.ca/imoweb/marketdata/marketData.asp). The IESO "Market Rules" describe near-term weekly (3 and 4 weeks out) and daily (up to 14 days out) forecasts and assessments (C. 5, S.7.1.1 of the market rules). The "Market Rules" also require the IESO to produce System Status Reports at specific times and under certain conditions. The procedures for the short-term forecasts and assessments are described in "Market Manual 2: Market Administration".

The purpose of the Weekly SAA Report and the Daily SAA Report is to inform market participants of expected conditions on the IMO-controlled grid and in the IESO-administered markets in the near-term, up to 4 weeks out. The information should assist market participants in making appropriate operational decisions.

The purpose of the System Status Reports is to inform market participants of expected conditions on the IESO-controlled grid and in the IESO-administered markets in the current day up to two days out.

The SSR and the Daily SAA Report cover the current day (day 0) out to 14 days (day 14) with hourly granularity. The SSR covers days 0-2 while the Daily SAA Report details days 3-14. The SSR and the Daily SAA Report are the same except that the SSR includes System Advisories and pre-schedules of intermittent, self-scheduling and transitional scheduling generators. Each day, the IESO publishes a Daily SAA Report that includes a new day 14 (i.e yesterday's 'day 15', part of the Weekly SAA Report). Each day, the IESO publishes a SSR with a new day 2 (i.e. yesterday's day 3, part of the Daily SAA report).

At any time, the IESO will update the SSR and/or Daily SAA for any hour for which there has been a material change.

The weekly SAA Report covers the days beyond the Daily SAA Report period – that is, day 15 and out. Every Thursday, the IESO will publish a new Week 4 (i.e. 25-31 days out) for the Weekly SAA Report. At any time, the IESO will update the Weekly SAA Report for any day for which there has been a material change.

SHORT-TERM AND LONG-TERM REPORTS

If market participants require additional information with regard to IESO interconnections beyond the time frame of the SAA and/or the SSR, participants can access additional information via the Transmission Rights Auction (http://www.ieso.ca/imoweb/marketdata/marketData.asp). The short-term pre-auction reports (Pre Auction TTC ST) indicate what the forecasted Total Transfer Capability (TTC) is on a monthly basis. The monthly values are based on the lower of the monthly thermal ratings, stability limit, or voltage limits. The long-term pre-auction reports (Pre Auction TTC LT) indicate what the forecasted TTC is on a yearly basis. The long-term TTC values are based on the lower of summer or winter thermal ratings, stability limits, or voltage limits.

New York Independent System Operator TTC/ATC Methodology

Introduction:

This document describes the underlying assumptions used in determining TTC and ATC on NYISO transmission interfaces as well as the use and meaning of the applicable margins in use namely TRM and CBM.

Transmission Transfer Capability

Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The NYISO has the responsibility of calculating Interface Transfer Capabilities of the NYS Transmission System (both within NYS and on the Interfaces between the NYCA and neighboring Control Areas), from time to time, as required by the Reliability Rules.

The units of transfer capability are in terms of electric power, generally expressed in megawatts. In this context, "area" may be an individual electric system, power pool, Control Area, sub region, NERC Region, or a portion of any of these. Transfer capability is also directional in nature, That is, the transfer capability from Area A to Area B is not generally equal to the transfer capability from Area B to Area A.

Capability versus Capacity:

Individual transmission line capacities or ratings cannot be added to determine the transfer capability of a transmission path or interface (transmission circuits between two or more areas within an electric system or between two or more systems). Such aggregated capacity values may be vastly different from the transmission transfer capability of the network. Generally, the aggregated capacity of the individual circuits of a specific transmission interface between two areas of the network is greater than the actual transfer capability of that interface.

Limits to Transfer Capability:

The ability of interconnected transmission networks to reliably transfer electric power may be limited by the physical and electrical characteristics of the system including any one or more of the following:

- ***Thermal Limits*** — Thermal limits establish the maximum amount of electric current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

- ***Voltage Limits*** — System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits. A widespread collapse of system voltage can result in a blackout of portions or the entire interconnected network.

- ***Stability Limits*** — The transmission network must be capable of surviving disturbance through the transient and dynamic time periods (from milliseconds to several minutes, respectively) following the disturbance. If a new, stable operating point is not quickly established after a disturbance, the generators will likely lose synchronism with one another, and all or a portion of the interconnected electric systems may become unstable. The results of generator instability may damage equipment and cause uncontrolled, widespread interruption of electric supply to customers.

The limiting conditions on some portions of the transmission network can shift among thermal, voltage, and stability limits as the network operating conditions change over time.

Determination of Transfer Capability:

The calculation of transfer capability is generally done with computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. Each simulation represents a single "snapshot" of the operation of the interconnected network based on the projections of many factors, such as:

- customer demands
- generation dispatch
- system configuration
- base scheduled transfers
- system contingencies

The conditions of the interconnected network continuously vary in real time. Therefore, the transfer capability of the network will also vary from one instant to the next. For this reason, transfer capability calculations are updated periodically for applications in the operation of the network.

The Total Transfer Capability (TTC) between any two areas or across particular paths or interfaces is the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.

3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in (2) above, and after the operation of any automatic operating system, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility

loadings are within emergency ratings and all voltages are within emergency limits.

4. With reference to condition (1) above, in the case where pre-contingency facility loadings reach normal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.

5. In some cases, individual system, power pool, sub regional, or Regional planning criteria or guides may require consideration of specific multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive that the single contingency consideration described above, the more restrictive reliability criteria or guides must be observed.

TTC = Minimum of {Thermal Limit, Voltage Limit, Stability Limit}

The NYISO's calculation of Transfer Capability will be consistent with NERC, NPCC, and NYSRC standards and criteria. These calculations will be performed by the NYISO through the execution of off-line and real-time analytical processes (i.e., SCUC, RTD, and the RTC).

Available Transfer Capability

Available Transfer Capability (ATC) between two areas is a measure of the transfer capability remaining in the physical transmission network. This capability may be used for further commercial activity over and above already committed uses (for a specific period for a specific set of conditions). The amount reserved to support existing transmission commitments is defined in the Existing Transmission Agreements and Existing Transmission Capacity for Native Load. Mathematically, NERC defines ATC as the Total Transfer Capability less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

The NYISO assesses available transfer capability ("ATC") when developing the Day-Ahead and Real-Time schedules using the SCUC and RTC processes and dispatching the NYS Power System in real-time with RTD. Transfer capability is evaluated based on base system loading and an assessment of critical contingencies on the Transmission System.

ATC may be defined as:

ATC = TTC – Transmission Interface Flow Utilization – (TRM) – (CBM)

Transmission Interface Flow Utilization is based upon the resulting interface power flows of the NYCA generation commitment, load pattern and external control area transactions determined by the DAM and RTS evaluations. The scheduling of firm counter flow external control area transactions in either the DAM or RTS can create the equivalent of NYISO RTD increased capacity at an external control area interface that will be reflected in Real-Time Scheduling (RTS). Transmission Interface Flow Utilization. The ATC is the remaining transfer capability based on the Transmission Interface Flow Utilization, less any Transmission Reliability Margin (TRM) that may be warranted. For DAM and RTS scheduling purposes, Capacity Benefit Margin (CBM) is not used by NYISO.

ATC Postings

Two values of ATC, one for firm and one for non-firm transactions, are determined as a result of each SCUC and RTC evaluation process. As a final step in the SCUC and RTC processes the Non-Firm Transaction Scheduler (NFTS) performs the calculation for determining ATC values. ATC is first calculated taking into consideration only firm transactions with the resultant value being ATC exclusive of non-firm transactions. The Non-Firm Transaction Scheduler subsequently determines if there is remaining ATC for submitted non-firm transactions for the given study period. NFTS will then schedule those non-firm transactions and calculate the ATC value inclusive of non-firm transactions. Both ATC values are then posted to the NYISO OASIS as “ATC w/o Non-Firms” and “ATC w/Non-Firms” for the respective study period.

ATC for the Day-Ahead Market

In the DAM, the SCUC process calculates ATC values for each hour of the next day. The DAM SCUC run incorporates the TTC values for each operating interface recognizing scheduled transmission facility maintenance outages. ATC values are determined based upon the interface power flows as a result of the generation commitment, load pattern and external control area transactions in the forecast re-dispatch pass of the SCUC evaluation. Note that DAM prices, including congestion costs, are the result of the bid load re-dispatch pass of the SCUC evaluation. Therefore, DAM values of ATC based on the forecast redispatch pass cannot be directly related to DAM LBMP congestion values that result from the bid load re-dispatch pass of SCUC. The forecast re-dispatch and bid load Redispatch passes of the SCUC evaluation are detailed in Technical Bulletin #49. Following the completion of the DAM process, the TTC and ATC values for each interface are then posted on the NYISO OASIS.

ATC for the Real-Time Market

The NYISO monitors existing system conditions and implements the RTS evaluation for a three-hour period, beginning with the next hour and forward for the next two consecutive hours. The RTS evaluates all accepted DAM bids and additional Hour Ahead bids received. The TTC values for the RTS evaluation are based on the known hourly maintenance schedules of generation and transmission. The TTC values also consider real time outages that may not have been prescheduled in the DAM. In addition, the NYISO Operator may adjust the TTC’s in the RTS based upon real time operating conditions to address in-day reliability issues of the NYISO Secured System. Following the top-of-the-hour RTS execution process, on an hourly basis forty-five minutes before the start of the next hour, the TTC's and ATCs are updated and posted on the NYISO OASIS.

Real Time Operations

Total Transfer Capability and ATC values are not posted in real time, but are represented by those values that are posted on an hourly basis. In-hour changes that may occur are not posted on the NYISO OASIS until the next hour RTS evaluation is posted.

Total Transfer Capability

The NYISO develops Total Transfer Capability (TTC) values for the transmission operating interfaces within and relating to the NYCA as defined in the ***NYISO Transmission and Dispatching Operations Manual***. Interfaces in New York are a predefined set of transmission circuits that represent transfer capability between Locational Based Marginal Pricing (LBMP) load zones and neighboring control areas. These interfaces are defined within the Security Constrained Unit Commit (SCUC) and Real-Time Commitment (RTC) software.

These interfaces are also defined as flow gates for NERC procedures. The interfaces are monitored in SCUC for the DAM and in RTC for the RTS processes. Following the top-of-the-hour RTC execution process, on an hourly basis forty-five minutes before the start of the next hour, the TTC's and ATCs are updated and posted on the NYISO OASIS.

TTC values are also provided for the next 30-day period to account for all scheduled transmission facility maintenance outages. The NYISO Transfer Limit Report (see NYISO OASIS at http://www.nyiso.com/public/pdf/ttcf/ttcf.pdf) indicates the normal TTC value with all facilities in service and the reduced TTC value corresponding to the maintenance outage condition(s) listed.

Offline studies performed by the NYISO in cooperation with NYISO Committees and neighboring control areas as well as NPCC studies are utilized in addition to real time system monitoring to determine the appropriate TTC values for the DAM and RTS time frames. The TTC values are reviewed by NYISO Market Operations and may be updated as warranted to ensure that accurate values are posted. TTC values for the interfaces are the result of thermal, voltage and/or stability limitations. TTC values for all NYISO interfaces include a normal operating margin in lieu of a Transmission Reliability Margin component. The normal operating margin is typically 100MW for all scheduling interfaces.

Transmission Reliability Margin

Transmission Reliability Margin (TRM) is defined as the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. Transmission Reliability Margin provides a reserve transfer capability that ensures the reliability of the interconnected transmission network under a broad range of potential system conditions.

Transmission Reliability Margin accounts for the inherent uncertainty in system conditions and their associated affects on TTC and ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change. The TRM may be applied to the ATC calculation to address unanticipated system conditions such as normal operating margin, parallel flows, load forecast uncertainty and other external system conditions. The TRM may be used to insure the transmission system is not over scheduled thus causing or aggravating real time operational problems. For firm scheduling purposes in the DAM and RTS, TRM is not used by the NYISO. TTC values for all NYISO interfaces include a normal operating margin in lieu of a TRM component.

Capacity Benefit Margin

Capacity Benefit Margin (CBM) is defined as that amount of Transmission Transfer Capability reserved by Load Serving Entities to ensure access to generation from interconnected systems to meet generation reliability requirements. 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 transmission capacity associated with CBM will not be withheld from the scheduling or dispatch of the NYS Transmission System in either the Day-Ahead or Real-Time Markets. Capacity Benefit Margin will not be reserved in any of the calculations or software that the NYISO will use for scheduling and dispatching the transmission system. Capacity Benefit Margin will not reduce the transmission capacity that is available for scheduling transactions. The NYISO will schedule transactions up to the limits of the transmission system, taking into account only the operating margin, which, unlike CBM, will be observed in actual system operation. Similarly, CBM will not be withheld in determining the quantity of Transmission Congestion Contracts (TCC's) that can be made available for the NYS Transmission System. The set of TCC’s that are assigned and sold for the system must be simultaneously feasible, i.e., they must correspond to a set of transactions that could be undertaken without violating any security limits on the system. The NYISO will be responsible for determining whether or not a given set of TCC’s passes this test. In doing so, it will not subtract CBM in determining the transmission capacity that is available for assignment or sale as TCC’s. The transmission capacity available as TCC’s will correspond to that available in the actual operation of the system, i.e., TCC’s will be sold up to the limits of the transmission system

ISO NEW ENGLAND

ATC METHODOLOGY

Rev. February 2005

1. INTRODUCTION

The New England Control Area covers the six New England states: Vermont, New Hampshire, Maine, Massachusetts, Connecticut, and Rhode Island.
Within New England Control Area there are 12 Transmission Providers (TP) and one Merchant Transmission Facility (MTF). They are:

<u>TRANSMISSION PROVIDERS:</u>

- Bangor Hydro Electric Company (BHE)
- Central Maine Power Company (CMP)
- Central Vermont Public Service Company (CVPS)
- Citizen Utilities Company (CZN)
- Florida Power and Light (FPL)
- Green Mountain Power Company (GMP)
- Maine Electric Power Company (MEPCO)
- **ISO New England (ISNE)**

  - also known as the Pool Transmission Facilities (PTF)
- New England Power Company (NEP)/National Grid USA.
  - It includes former Eastern Utilities Association (Montaup) (EUA)
- Northeast Utilities System (NU)
- NSTAR:
  - Former Boston Edison Company (BECO)
  - Former Cambridge Electric Company (CELC)
  - Former Commonwealth Electric Company (COM)
- United Illuminating Company (UI)
- Unitil (UNITIL)
- Vermont Electric Company (VELCO)

<u>MERCHANT TRANSMISSION FACILITY:</u>

- Cross Sound Cable (CSC)

ISO New England (ISO) provides administration services for the ISO New England Transmission Provider (ISNE). This document describes the methodology used by ISO to calculate Total Transfer Capability (TTC) between the New England Control Area and neighboring Control Areas (New York, Quebec and New Brunswick). The document also describes the Available Transfer Capability (ATC) between ISNE and non-ISNE interfaces.

The other transmission providers and the transmission merchant facility listed above have their own methodologies.

TTC and ATC values for ISNE are posted on the ISO NEW ENGLAND OASIS under the ISNE Node. Transmission Services for the other transmission providers are also posted on the ISO NEW ENGLAND OASIS under their unique nodes.

2. OPEN ACCESS WITHIN ISO NEW ENGLAND

There are two types of Open Access for transmission services available in the New England Control Area: financial transmission under the Standard Market Design System (SMD) and the Physical transmission under the traditional Pro Forma Reservation System.

ISNE Services under SMD

The implementation of the Standard Market Design (SMD) on March 1st 2003 has changed the calculation, posting and use of ATC values on the ISNE Node.

Under SMD rules, there are no advanced transmission reservations required for external transactions over the ISNE facilities known as Pool Transmission Facilities (PTF). External energy is scheduled economically based on offers and bids within the SMD, and transmission service is automatically granted to those offers and bids that are scheduled to flow at the beginning of the scheduling hour.

Requests for external energy schedules are not restricted by the ATC value at the time of submittal. The posted ATC is simply calculated based on the MW amount of accepted offers and bids submitted to the market and serves as an indicator of the requested utilization of the external interfaces. Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM), parameters associated are not needed for the Market System and have zero MW value.

Under SMD the need to calculate both Firm and non-Firm ATC will no longer be required. Since transmission service will be granted as part of a transaction that actually flows, all service will have the same priority, therefore ATC will be representative of this.

Physical Based Transmission Service

The other Transmission Providers within New England will continue offering advanced reservations for Pro Forma transmission service under the traditional Physical Reservation System. Firm and non-Firm ATC will continue to be decremented by advance reservations and where appropriate TRM

3. ISO NEW ENGLAND INTERFACES

The following is a list of Transmission providers that offer service over the external Control Area Boundaries. With the exception of the New York free-flow ties and the Highgate tie, all other external control area interfaces required service from both the ISNE and another Transmission Provider.

Note: Appendices A, B, and C provide further detailed information of interfaces.

ISNE – Interfaces

- NE –New York (Free-Flow Ties),
- NE –MEPCO
- NE – Phase I/II (Comerford / Sandy Pond)
- NE – Highgate
- NE – Cross Sound Cable

(Note: Market Based Service, No physical reservations are needed)

MEPCO – Interfaces

- MEPCO – ISNE
- MEPCO – New Brunswick

(Note: Advance Physical Reservations required, administered by MEPCO)

Phase I/II – Interfaces

- Phase I/II – ISNE (Comerford / Sandy Pond)
- Phase I/II – Hydro Quebec

(Note: Phase I and II cannot operate simultaneously. Normal Operation is over Phase II facility. Advance Physical Reservations required, administered based on ownership share by NSTAR, CMP, CVPS, Citizens Utilities, GMP, NEP, NU and UI)

Highgate – Interface

- ISNE– Hydro Quebec

Cross Sound Cable – Interfaces

- CSC – ISNE
- CSC – New York (Long Island) (Note: Advance Physical Reservations required, administered by CSC)

4. TOTAL TRANSFER CAPABILITY (TTC)

NERC Definition

The Total Transfer Capability (TTC) for an interface is the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame.

Basis For TTC

TTCs for ISO NEW ENGLAND interfaces are forecast by the ISO based on thermal, voltage, and/or stability limitations of the ties that comprise the interface. Power flow and transient stability analysis is used to ensure that physical limits will not be violated for credible system contingencies per NPCC and ISO NEW ENGLAND reliability criteria.

Future Forecasts

The TTC forecast for periods beyond 40 days out is based on seasonal operating studies that take into account anticipated peak loads and generator maintenance schedules.

Within 40 days, a base TTC is calculated from historical "all lines in" data that takes into account seasonal load distributions. The base TTC is adjusted daily into a forecast value that accounts for:

- Forecast loads
- Actual and scheduled transmission and generator outages in ISO NEW ENGLAND and neighboring systems
- Changes in facility ratings
- Anticipated loading of generators
- Anticipated inter-Area schedules or bids and offers for the Market System

Variations Across Interfaces

Factors used in calculating TTC for each of the ISO NEW ENGLAND interfaces vary.

ISO vs. Transmission Provider Responsibility

ISO will calculate and post TTC for ISNE and the external Control Area Interfaces.

Individual Transmission Providers will post TTC for their individual system.

(Note: ISO provides a service to the other Transmission Providers to fulfill this requirement and provide coordination between the interfaces within New England.)

ISNE Posted TTC Values (as posted by ISO-NE)

Hourly TTC

Hourly values are provided for the current day, plus the next 7 days, for each ISNE interface

Adjustments made to the base TTC values for posted interfaces can be seen in hour-byhour detail.

The Hourly TTC is the MINIMUM TTC for that Hour.

Daily TTC

Daily values for the current day plus the next 39 days for each ISNE interface.

The TTC values for the first 8 days in this group are adjusted for hourly maintenance and details can be viewed in the Hourly TTC section. Days 9 through 40 use historical database TTC values.

The Daily TTC is the MINIMUM Hourly TTC for the Day.

Weekly TTC

Weekly values are shown for the current week plus the next 12 weeks for each interface.

A week always starts at 0001 on a Monday and ends hour ending 24 on the following Sunday.

Note that the TTC values for the first 5 weeks (made up of the current week plus the next 5 weeks) will reflect adjustments made for known hourly or daily maintenance.

The Weekly TTC is the MAXIMUM Daily TTC for the 7-day week.

Monthly TTC

Monthly values cover the current month and the next 12 months for a total of 13 calendar months. Each interface has the **MAXIMUM** value posted which is based on the historical data.

If maintenance is scheduled for an entire month it will be reflected in the Monthly TTC. *The Monthly TTC is the MAXIMUM Daily TTC for the month.*

Yearly TTC

Yearly values reflect 2 years beyond the current year.

Yearly TTC is the MAXIMUM value between summer and winter Analysis for the year.

5. TRANSMISSION RELIABILITY MARGIN (TRM)

Definition

The Transmission Reliability Margin (TRM) is the portion of TTC that cannot be used for reservation of firm transmission service because of uncertainties in system operation. It is used only for interfaces under the physical reservation system.

Variability Of TRM

The TRMs are interface-dependent, direction specific and time-dependent.

ISO vs. Transmission Provider Methodology

For Market based ISNE services, there is no TRM and it has zero MW value

For Physical based services TRM will be dependant on forecasted system conditions and the interface.

TRM Values

INTERFACE	TRANSMISSION PROVIDER	TRM
NY-NE	ISNE	0 MW
PHASE II/I (NE-HQ)	Individual Owners	Posted by TPs
HIGHGATE (NE-HQ)	ISNE	0 MW
NB- NE	ISNE and MEPCO	Posted by MEPCO
CSC (NE-LI)	ISNE and CSC	TRM=346MW(both directions)

NOTE: Appendix D illustrates typical TRM and TTC values for the interfaces under the Physical Reservation System. The exact values are posted on the appropriate OASIS node

6. CAPACITY BENEFIT MARGIN (CBM)

Definition

The Capacity Benefit Margin (CBM) is the required MW amount of Total Transfer Capability to meet generation reliability requirements. CBM allows Load Serving entities to reduce its installed generating capacity. CBM is an importing quantity.

Capacity Benefit Margin Under SMD

The implementation of the Market System in the New England Control Area (May 1999) eliminated the need to hold transmission capability from the Market in the form of Capacity Benefit Margin (CBM). ISO New England uses zero MW of CBM when calculating Available Transfer Capabilities on its interconnection with other Control Areas.

Under the current Standard Market Design (SMD) implemented on March ^{1st} 2003, Load Serving Entities (LSEs) operating in the New England Control Area are required to arrange their Installed Capability requirements (generation reliability requirements) prior to the beginning of any given month.

Since the present SMD accepts bids and offers only for 10 days ahead for a maximum duration of 30 days and there are no transmission reservations under SMD, CBM is zero MW and all LSEs in New England must meet generation requirements before actual dispatch occurs.

7. AVAILABLE TRANSFER CAPABILITY (ATC)

ATC For Market Based Services

SMD does not require physical reservations for transmission service on the PTF; therefore, the designation of Firm and Non-firm to ATC in regard to the PTF is no longer appropriate. There is only a single value for ATC

ATC is used as an indicator of utilization of the interfaces.

The market ATC will be calculated according to the following equations:

- Hourly ATC = TTC –Submitted Schedules (current day plus 7 days in advance)
- Daily ATC = TTC –Submitted Schedules (current day plus 39 days in advance)
- Weekly ATC = TTC –Excepted Transactions Reservations (current week plus 5 weeks in advance)
- Monthly ATC = TTC –Excepted Transactions Reservations (current month plus 12 months in advance)
- Long Term ATC = TTC –Excepted Transactions Reservations (up to 2 years in advance)

Negative ATC

Negative ATC in the market-based system can be an indication of increased demand for transactions flowing in a particular direction. Since ATC will not limit the amount of transactions to be considered for scheduling there could be times when ATC indicates a substantially negative value. It must be recognized that a negative ATC should not discourage the submittal of a transactions, as the economic evaluation of these schedules has not taken place. It is this economic evaluation that will assure that transfer limits are honored.

Definition Of Firm ATC For The Physical Reservation System (non-PTF and MTF Transmission Services)

Firm Available Transfer Capability (Firm ATC) for an interface is the capability for firm transmission reservations that remains after allowing for existing firm commitments and the TRM. Mathematically, Firm ATC is calculated using the equation:

FIRM ATC = TTC – TRM – CBM (for Imports) – Existing Firm Commitments *

* Existing Firm Commitments consist of, Firm transmission requests in the following status: Confirmed, Accepted and Study.

Definition Of Non-Firm ATC For The Physical Reservation System (non-PTF and MTF Transmission Services)

Non-firm Available Transfer Capability (Non-Firm ATC) for an interface is the capability for non-firm transmission reservations that remains after allowing for existing commitments in the Confirmed and Accepted status.

Mathematically, Non-Firm ATC is calculated using the equation:

- NON-FIRM ATC = TTC – Existing Firm & Non-Firm Commitments in the Confirmed and Accepted Status.

8. DETERMINATION AND POSTING OF TTC AND ATC

Location Of Posting

TTC and ATC values for all New England interfaces are posted on the ISO NEW ENGLAND OASIS web page (PTF, non-PTF and MTF). The values are accessed through the OASIS node by selecting the Transmission Provider's page (ISNE, MEPCO, CSC, etc.). Some interfaces are posted by more than one Transmission Provider, such as, Phase I/II where there is joint ownership.

Updates To TTC And ATC

TTC and ATC values are calculated and posted for each of the following time frames:

- Hourly
- Daily
- Weekly
- Monthly
- Yearly

Base TTC values for the longer term postings are determined using "all lines in" normal system configuration. Closer to real time, changes to the normal configuration as a result of scheduled maintenance or unscheduled outages are known and can result in more or less restrictive transfer limitations.

Short-term analysis may be performed to assess the effects of outages and other changes on base TTCs. Adjustments to the base TTC values are made to nearer term values as appropriate to reflect the changes in limitations.

Updates To TTC

The ISO evaluates all TTC values, with the exception of yearly values, for each interface a minimum of once per business day and whenever changes in system conditions warrant.

Updates To ATC

Market Based

The ISO has software applications that dynamically recalculate the single value ATC and update the OASIS posting as each transaction request with the ISO NEW ENGLAND RTG is received.

Physical Reservation Based

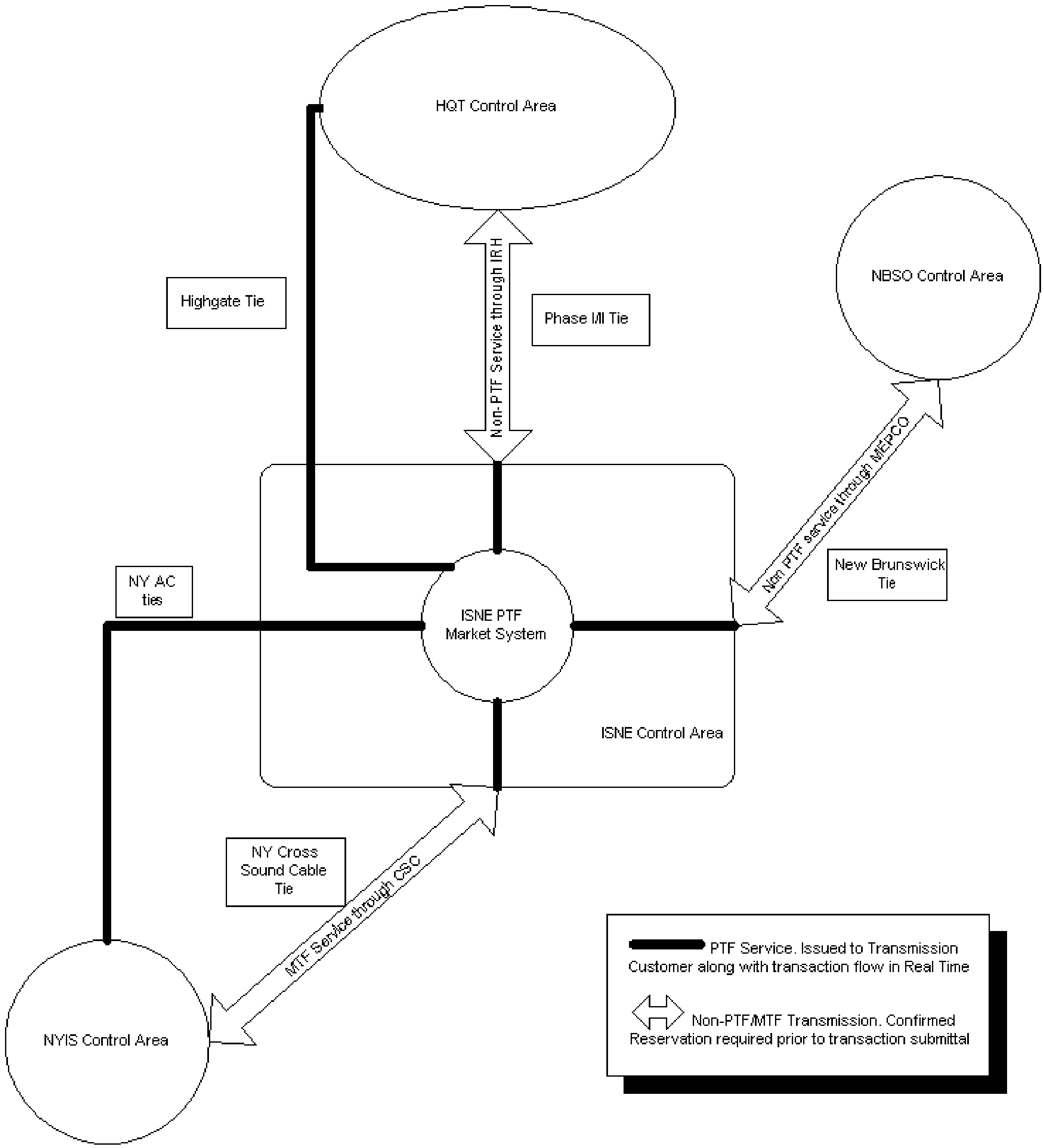
Individual Transmission Providers will calculate ATC and post both TTC and ATC for their individual system.

Firm ATC and Non-Firm ATC values for the interface posted by other transmission providers are calculated and updated based on reservations received by those transmission providers.

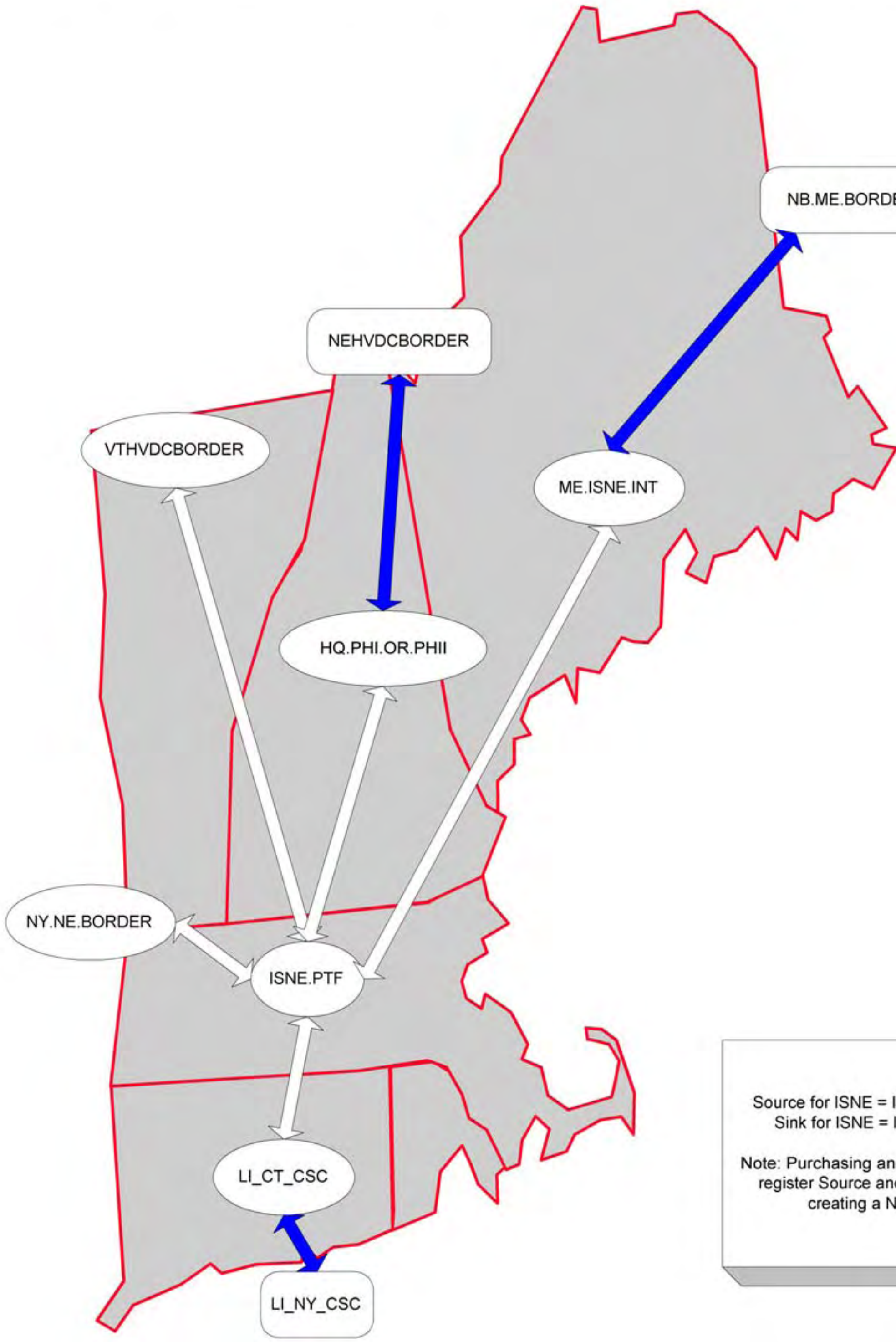
9. REFERENCES

- Transmission Transfer Capability. NERC, May 1995
- Available Transfer Capability Definitions and Determination. NERC June 1996
- NPCC Methodology and Guidelines for Forecasting TTC and ATC. NPCC. April 2001
- ISO NEW ENGLAND Open Access Transmission Tariff. Attachment C
- ISO NEW ENGLAND Operating Procedure 19 (OP19) Transmission Operations
- NPCC Document A2 Basic Criteria for Design and Operation of Interconnected Power Systems. January 2003

Appendix A: ISNE Control Area Reservation System



Appendix B:
POR and POD definitions within ISNE Control Area



Source for ISNE = ISNESYSPOWER
Sink for ISNE = ISNESYSLOAD

Note: Purchasing and Selling entity must register Source and / or sink prior to creating a NERC e-tag

APPENDIX C: DETAILED INTERFACES

Common Name/ External Node	Transmission Provider	Associated Transmission Facilities
NB-NE .I.KESWICK 345 1	ISNE and MEPCO	Keswick - Orrington (396 Line)
Phase I/II .I.HQ_P1_P2345 5	Individual Owners	HQ - Comerford 451+452 Lines (Phase 1) HQ - Sandy Pond 3512+3521 Lines (Phase 2)
Highgate .I.HQHIGATE 120 2	ISNE	Bedford - Highgate Line (1429 Line) (Georgia Tap)
NY-NE .I.ROSETON 345 1	ISNE	Plattsburg - Sandbar Line (PV-20 Line) Whitehall - Blissville Line (K-37 Line) Hoosick - Bennington Line (K-6 Line) Rotterdam - Bearswamp Line (E205W Line) Alps - Berkshire Line (393 Line) Salisbury - Smithfield Line (690 Line) Pleasant Valley - Long Mountain Line (398 Line) Northport - Norwalk Harbor (1385 Line)
CSC .I.SHOREHAM138 99	ISNE and CSC	Shoreham - Halvarsson Converter (481 Line)

NY=New York , NE=New England, HQ=Hydro-Quebec, LI = Long Island-NY, CSC=Cross Sound Cable

APPENDIX D - Typical TTC And TRM Values For Non-PTF (Physical Based) Interfaces

Cross Sound Cable (New York)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	346	= TTC	0	346	= TTC
Monthly	346	= TTC	0	346	= TTC
Weekly	346	= TTC	0	346	= TTC
Daily	346	= TTC	0	346	= TTC
Hourly	346	= TTC	0	346	= TTC

ISNE (MEPCO)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	700	TTC – 700	0	600	TTC x .10
Monthly	700	TTC – 700	0	790	TTC x .10
Weekly	700	TTC – 700	0	714	TTC x .10
Daily	700	TTC – 700	0	746	TTC x .10
Hourly	Dependant on Forecast Load	TTC – 700	0	Historic	TTC x .10

MEPCO (New Brunswick)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	700	50	0	600	=TTC
Monthly	800	50	0	790	=TTC
Weekly	1000	50	0	714	=TTC
Daily	1086	50	0	746	=TTC
Hourly	Dependant on Forecast Load	50	0	Historic	=TTC

Phase I/II (Hydro Quebec) * Phase I and II are not posted separately.

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	1800	TTC - 1200	0	1200	500
Monthly	2000	TTC - 1200	0	1200	500
Weekly	2000	TTC - 1200	0	1200	500
Daily	2000	TTC - 1200	0	1200	500
Hourly	2000	TTC - 1200	0	1200	500

Highgate (Hydro Quebec)

	Import TTC	Import TRM	Import CBM	Export TTC	Export TRM
Yearly	218	TTC - 200	0	20	= TTC
Monthly	225	TTC - 200	0	20	= TTC
Weekly	225	TTC - 200	0	20	= TTC
Daily	225	TTC - 200	0	20	= TTC
Hourly	225	TTC - 200	0	Dependant on Forecast Load	= TTC

Hydro Québec
TransÉnergie

TRANSÉNERGIE TRANSFER CAPABILITIES

Release Note

This version supercedes that dated November 15, 2002.

A substantive change has been made to the one item below:

- methods for calculating TTC and TRM for deliveries over interconnections comprising generating stations synchronized to neighboring systems.

  For interconnections involving generating stations synchronized to a neighboring system, TTCs toward the neighboring systems amount to the transfer capability between the generating stations and the neighboring system.

Besides the above change, various passages have been reworded to make it easier to understand, we hope, TransÉnergie practices with respect to calculating and posting system transfer capabilities.

I - Introduction

Following industry standards, transfer capabilities over TransÉnergie OASIS paths can be expressed by the generic equation below:

ATC = TTC – TRM – existing transmission commitments

ATC (available transfer capability) denotes the transmission capacity available for wholesale over a given path during a given future period of time. ATC values are thus values forecast for a given future hour, day, week, month or year. TTC (total transfer capability) denotes the capacity it is feasible to transmit over a given path during a given future period of time (hour, day, month or year). TRM (transmission reliability margin) quantifies the variability and imprecision of transfer capability forecasts. TRM is used in calculating non-recallable ATC (NATC), or firm ATC; it is not used in calculating recallable ATC (RATC), or non-firm ATC.

Section II, *Factors Affecting OASIS Path Transfer Capability*, sets out key factors impacting TTC and TRM forecasts.

Section III, *General Principles for TTC and TRM Forecasts*, sets down rules for developing TTC and TRM calculation methods.

Readers must note that in this document the term “interconnection” applies exclusively to interconnections linking two transmission systems.

II – Factors Affecting OASIS Path Transfer Capability

The various factors affecting TransÉnergie transfer capabilities are listed below and later explained individually:

- transfer capability of interconnection networks
- interconnection equipment ratings
- equipment outages for facility maintenance
- loads linked to interconnection systems
- generation linked to interconnection systems
- first-contingency load loss (FCLL) limit
- first-contingency generation loss (FCGL) limit
- total control area wheel-in capacity

II.1 Transfer capability of interconnection networks

Interconnection systems are generally comprised of regional transmission systems carrying power at 120 kV, 230 kV or 315 kV. These systems feed interconnections and sometimes also load-serving substations. The transfer capability of such systems can be limited by thermal constraints of component facilities (transformers, transmission lines). The transfer capability of such systems can also be limited by minimum-voltage constraints of nearby load-serving substations or by stability constraints of nearby generating stations.

II.2 Interconnection equipment ratings

Normally, the thermal capacity of equipment at an interconnection point varies as a function of the ambient temperature at the interconnection substation. For most equipment, increased temperature results in decreased capacity.

II.3 Equipment outages for facility maintenance

For facility maintenance purposes, power system equipment must occasionally be taken out of service. Such outages can sometimes reduce the transfer capability of interconnections. Annual availability of TransÉnergie interconnection facilities is estimated at 95% or more. Outages lasting less than 5% of the posted period are ignored in calculating monthly and yearly ATC. Major upgrades to key facilities can lower annual availability to 80%. These are exceptional events normally announced at least one year in advance. They are scheduled taking into account the requirements of customers who have reserved transmission capacity.

II.4 Loads linked to interconnection systems

Some interconnection networks feed load-serving substations along the way. For deliveries to a neighboring system, the transfer capability at the interconnection point is then determined by the interconnection networks' transfer capability less the value of the load served by these substations.

II.5 Generation linked to interconnection networks

Some interconnection systems are partly supplied by local generating stations. For flows from a neighboring system, the interconnection's transfer capability is determined by its capacity to receive less the amount of generation from local stations.

For certain interconnections, energy transfer between systems is achieved by transferring a block of generation from one system to another. In such instances, the capacity that can be delivered to the neighboring system is determined by rated output of the generating stations that can be transferred to the neighboring system.

II.6 First-contingency load loss (FCLL) limit

The tripping of an interconnection being used for deliveries means a loss of load on the system and results in a rise in system frequency. In order to ensure TransÉnergie system integrity and continuity of service to customers connected to the TransÉnergie system, the system operator limits the amount of load (MW) that can be tripped in the event of a single incident. This FCLL limit depends on the spinning capacity feeding the system and on the interconnection's location. The greater the spinning capacity, the higher is the FCLL limit. Generally, spinning capacity increases with deliveries, decreases with receipts and follows changes in load. The FCLL limit is thus most constrictive at low loads and maximum receipts.

II.7 First-contingency generation loss (FCGL) limit

The tripping of an interconnection being used to receive power means a loss of generation on the system and results in a drop in system frequency. Like the FCLL limit, the FCGL limit helps control system frequency deviations. In order to ensure TransÉnergie system integrity, only limited generating capacity can be tripped in the event of a single incident. The FCGL limit depends on the spinning capacity feeding the system. The greater the spinning capacity, the higher is the FCGL limit. Generally, spinning capacity increases with deliveries, decreases with receipts and follows changes in load. The FCGL limit is thus most constrictive at low loads and maximum receipts.

II.8 Total control area wheel-in capacity

Total wheel-in capacity of the Québec Control Area varies as a function of the balance of the system load, deliveries to neighboring systems, and the minimum generating capacity to be maintained on the system. Wheel-through service (simultaneous receipt and delivery) is not affected by the control area's total wheel-in capacity.

III – General Principles for TTC and TRM Forecasts

This Section sets out the guiding principles for calculating TTC and TRM values posted for TransÉnergie OASIS paths. Calculation methods specific to each OASIS path can be found on the TransÉnergie OASIS site in “Miscellaneous information” under “TTC and TRM calculation methods”. The principles set out below comply with the latest version of *NPCC Methodology and Guidelines for Forecasting TTC and ATC* (April 2001 Draft) that can be found at:

http://www.nerro.org/pdfs/NPCC_Methodology_41901.pdf.

The calculation methodology was established following NERC guidelines while considering NPCC region specifics. It is worth noting that the Hydro-Québec system is connected asynchronously to the rest of the Northeast region, so electrical characteristics of our interconnections are quite unlike others. These interconnections comprise the essential TransÉnergie OASIS paths.

The reader must note that the principles discussed were valid at the time this document was drafted but are apt to be further refined and developed in light of changes to industry rules, standards and guidelines and TransÉnergie system’s unique characteristics. Since these changes can take some time to implement, there may arise temporary discrepancies between actual TTC and TRM calculation and posting practices and the principles set out below.

III.1 Definition of TTC and TRM for OASIS paths

TTCs are projected transfer capabilities between two locations. These transfer capabilities must be feasible without jeopardizing system and facility security. For interconnections, TTC values are assessed at the boundary of TransÉnergie facilities.

Projected TTC values for a path are always less than or equal to that path’s reference total transfer capability (TTC_{ref}). TTC_{ref} is a value proven feasible without jeopardizing security. The proof of this is based on system stability studies or on measurements under actual operating conditions. The system studies used to set TTC_{ref} are carried out by simulating systems with existing or planned interconnected networks.

For interconnections involving generating stations disconnected from the Québec system and reconnected to a neighboring system, TTCs toward the neighboring system amount to the transfer capability between the generating stations and the neighboring system.

Since TTC is a forecast value based on several assumptions, every TTC value has an associated forecasting error, the TRM.

TTC and TRM are values used for business purposes to determine the transfer capabilities available for wholesale power transmission.

NATC = TTC – TRM – existing transmission commitments

RATC = TTC – existing transmission commitments

TTC and TRM are closely related and for each TTC calculation, an associated TRM is calculated. That TRM may equal zero.

III.2 Determining TRM

TRM is calculated as the difference between maximum potential TTC during a given period and the minimum transfer capability available for the major part of the same period. TRM values quantify inaccuracies associated with transfer capability forecasts. These inaccuracies stem from the variability of certain parameters affecting TTC (system load, ambiant air temperature, internal generation on the interconnection system, and spinning capacity of the system as a whole). Potential transmission equipment or generating unit failures are currently not factored into TRM calculations.

III.3 Native loads affecting transfer capability at points of delivery

For deliveries, when loads on the Québec side of the border affect available transfer capability at the border, the effect of such native loads is factored into TTC calculations.

III.4 Internal generation affecting transfer capability at points of receipt

For power received, when priority generating requirements on the Québec side of the border affect available transfer capability at the border, the effect of such native generation is factored into TTC calculations.

III.5 Internal radial generation

For interconnections involving a generating station reconnected to a neighboring system, the TTC for delivery to that system is based on transmission capacity without regard to the station's available output. The interconnection's TTC_{ref} does, however, take into account the generating station's rated output.

HQT-MASS is comprised of an asynchronous transmission link (DC converters) and a generating station that can be reconnected to a neigboring system (radial generation). For this particular interconnection, an exception, transfer capability for deliveries is based on available radial generation and transmission facility transfer capability.

III.6 Partial coordination of TTC with neighboring systems

TTC values for a specific period are calculated based on projected system operating conditions for that period. Such values are not coordinated with the neighboring system's calculated TTCs but at no time exceed TTC_{ref} values.

TTC_{ref} values are coordinated with the neighboring system at the design stage and are reassessed annually during operation.

The transfer capability of neighboring systems has a direct impact on the amount of power that can be transferred over interconnections. Except for jointly owned interconnection facilities, parameters outside TransÉnergie control (planned facility outages, and system operating conditions and limits) that affect the transfer capability of neighboring systems are not factored into TransÉnergie TTC calculations. Each system determines and posts its own TTC values. Operating conditions on neighboring systems can bring constraints on top of TransÉnergie constraints.

III.7 External radial load (neighboring system)

For an interconnection where load-serving substations on the neighboring system can be reconnected to the TransÉnergie system, the TTC_{ref} value for deliveries is determined by those substations' peak annual load or as the maximum load the TransÉnergie system has proven it can safely supply. The actual value of available load does not enter into the TTC calculation.

III.8 External radial generation

For an interconnection where a generating station on the neighboring system can be connected to the TransÉnergie system, the TTC_{ref} value for power received is based on the amount of installed capacity that can be safely linked to the interconnection. The actual value of available generation does not enter into the TTC calculation.

III.10 Calculating the 35-day horizon

For the horizon between the next hour and 35 days hence, a TTC value is calculated for every hour based on mean forecast temperature, average projected load, and scheduled facility outages affecting interconnection transfer capability. TRM is zero barring exceptional circumstances.

III.11 Calculating the 13-month horizon

For the 13-month horizon, a set of TTC-TRM pairs is calculated, one pair for each of the 13 months. These pairs are used to determine each month's non-recallable ATC value, corresponding to at least 95% of the total hours in that month. The TTC value must be feasible for a period greater than or equal to 5% of the total hours in the month.

III.12 Calculating multi-year horizons

The multi-year horizon covers the current calendar year and the following year. A TTC-TRM pair is calculated for each of the years. These pairs are used to determine each year's non-recallable ATC value, corresponding to at least 95% of the total hours in that year. The TTC value must be feasible for a period greater than or equal to 5% of the total hours in the year.

ATTACHMENT C

Methodology For Calculating Transfer Capabilities for the Transmission Provider's Interfaces With Neighboring Utilities

Objective

The purpose of this document is to describe the methodology used to determine the Total Transfer Capability (TTC) and the Available Transfer Capability (ATC) of the interfaces between the Transmission Provider's Transmission System and the transmission systems of its neighboring utilities.

Determination of TTC

The Total Transfer Capability (TTC) of an interface is a best engineering estimate of the total amount of electric power, measure in MW, that can be transferred over an interface in a reliable manner for a given time frame.

The TTC of an interface is determined by performing power flow and stability studies under seasonal system conditions. Normal operation (all elements in service) and first contingency (N-1) scenarios are studied using summer and winter base case models to determine the summer and winter TTC of each interface. For the Non-Simultaneous TTC values, these studies are done on a single interface at a time, with power flows on all other interfaces equal to 0 MW. For Simultaneous TTC values, these studies are done taking into account all acceptable power flows which may occur simultaneously on the other interfaces. Simultaneous TTC values will be used in the calculation of Available Transfer Capability for OASIS posting purposes when real-time conditions warrant. The TTC value (simultaneous and non-simultaneous) for a given interface is defined as the lowest of the transfer limits defined by:

Thermal Limit: This limit is reached when the most restrictive element in the transfer path is loaded to its seasonal thermal limit. For normal operation, no element will be loaded above its Normal seasonal thermal rating. For first contingency operation, no element will be loaded above its Emergency seasonal thermal rating.

Voltage Limit: This limit is reached when, due to interface transfers, System Voltage levels fall outside of a certain acceptable range. For normal operation Voltages at all transmission levels will be kept in the range of 0.95 to 1.05 per unit. For first contingency operation, Voltages at all transmission levels will be kept in the range of 0.90 to 1.07 per unit.

Stability Limit: This limit is reached when, due to interface transfers, system instability may result during either normal conditions or single contingency scenarios.

Inclusion of Special Protection System (SPS) Actions in TTC Calculations

The Transmission Provider employs a number of Special Protection Systems (SPSs), designed in accordance with Northeast Power Coordinating Council (NPCC) guidelines, to enhance the transfer limits on its interfaces with its neighboring utilities. Whenever applicable, the SPSs are identified and their action is taken into consideration as a part of the TTC calculations.

Determination of Transmission Reliability Margin (TRM)

The Transmission Reliability Margin (TRM) is the portion of transfer capability which is reserved to cover for uncertainties in system conditions. A portion, or all, of the transfer capability reserved for TRM may be offered for non-firm transmission reservations/service. However, it cannot be offered for firm transmission reservations/service. TRM for Transmission Provider interfaces are determined to cover for uncertainties within the Transmission Provider's Transmission System and neighboring systems to maintain adequate Operating Margin to meet reliability requirements, including Reserve Pickup Margin (such as reserve sharing). At a minimum, TRM values will be such that following a single contingency, interface power flows up to the Firm ATC will not result in any transmission element being loaded above its seasonal normal thermal rating. Whenever applicable, associated SPSs are identified and their actions are taken into consideration as a part of the TRM calculations on a particular interface.

Determination of Capacity Benefit Margin (CBM)

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.

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.

Regional reviews of generation adequacy will continue to permit capacity imports from the interconnected systems.

Generation reliability requirements will be reviewed on a regular basis at least annually consistent with NPCC criteria

Determination of ATC

The Available Transfer Capability (ATC) of an interface is a measure, in MW, of the transfer capability remaining on an interface for further commercial activity over and above previously committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the Capacity Benefit Margin (CBM) less the sum of any existing transmission commitments.

Recallability is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with the OATT or other contract provisions. Therefore, ATC is calculated for two categories:

1) Firm ATC - which is not recallable (non-recallable)
2) Non-Firm - which is recallable

Procedure for Calculating the Firm ATC Values

The firm ATC value for a given interface, in a specific direction, is evaluated as follows *(the equations are the same for both the Operational and the Planning Horizons)*:

1) Determine the TTC value for this interface (taking into consideration any firm simultaneous transactions on other interfaces that impact the limit of this interface).
2) Determine the TRM and CBM values for this interface.
3) List all firm transmission reservations on the given interface, and calculate the total firm transmission reservation.
4) Firm ATC = TTC – TRM – CBM – Total Firm Transmission Reservations (all terms of the ATC equation are directional).

Procedure for Calculating the Non-Firm ATC

The Non-Firm ATC value for a given interface, in a given direction, is evaluated using different equations in the planning and operating horizons, as follows:

Planning Horizon: Beyond the operating horizon and takes into consideration the transmission reservations.

1) Determine the TTC value for this interface (taking into consideration the firm and non-firm transmission reservations on other interfaces that impact the simultaneous TTC value for this interface).
2) Determine the TRM and CBM values and the portion β of the TRM, that will not be available for any transactions, because of reliability concerns, where $O \leq \beta \leq 1$.
3) List all Firm Transmission Reservations, on the given interface, and calculate the total Firm Reservations.
4) List all Non-firm Transmission Reservations, on the given interface, and calculate the total Non-firm Reservations.
5) Non-firm ATC = TTC – β (TRM) – Non-firm Transmission Reservations – Firm Transmission Reservations (all terms of the ATC equation are directional).

Operating Horizon: Takes into consideration the transmission schedules.

1) Determine the TTC value for this interface (taking into consideration the firm and non-firm transmission schedules on other interfaces which impact the simultaneous limit of this interface).
2) Determine the TRM and CBM values and the portion (α) of the TRM, that will not be available for any transactions, because of reliability concerns, where $O \leq \alpha \leq 1$.
3) List all Firm Scheduled Services, on the given interface, and calculate the net schedule.
4) List all Non-firm Scheduled Services, on the given interface, and calculate the net schedule.
5) Non-firm ATC = TTC – (TRM) – Non-firm Transmission Schedules – Firm Transmission Schedules (all terms of the ATC equation are directional with the exception of the "net" schedule).

Updating Periods for the TTC, TRM, CBM and ATC

Updating of the TTC, TRM, CBM and ATC values will be done according to the following guidelines:

Updating the TTC Values:

The posted seasonal (summer and winter) TTC values for each individual interface, will be considered constant and valid for the entire season. TTC values will be reviewed and updated as necessary, to account for any changes in system conditions that may affect the TTC.

Updating the TRM and CBM Values:

The TRM and CBM values will be reviewed, and updated as necessary, to account for any changes in system conditions that may require new margins.

Updating the ATC Values:

The Firm and Non-Firm ATC values for the operating and planning horizons are automatically calculated and available on the OASIS based on the most up to date:

- Firm Scheduled Transmission Service.
- Non-Firm Scheduled Transmission Service.
- Firm Transmission Reservations.
- Non-Firm Transmission Reservations.
- TRM and CBM values.
- The magnitudes of α & β factors that may influence the amount of TRM that is available for non-firm transactions.
- Individual and Simultaneous TTC values

ATTACHMENT C

Methodology To Assess Available Transmission Capability

1. Objective

The purpose of this document is to describe the methodology used by the Transmission Provider to determine the Total Transfer Capability (TTC) and the Available Transmission Capability (ATC) between the Transmission Provider and its neighboring utilities. The Transmission Provider is Nova Scotia Power, Inc. (NSPI), which owns, controls, and operates facilities used for the generation and transmission of electric power and energy and provides transmission services under the OATT. NSPI is also the System Operator for the electric system in Nova Scotia.

The following documents were used as references:

i. *Revised NPCC Methodology and Procedure for the Determination and Posting of Available Transfer Capability*; NPCC Ad Hoc ATC Working Group Report, Northeast Power Coordinating Council, June 2, 1998

ii. *Available Transfer Capability Definitions and Determination*; North American Electric Reliability Council, June 1996.

iii. *Basic Criteria for Design and Operation of Interconnected Power Systems*; NPCC Document A-2, Northeast Power Coordinating Council, Revised August 9, 1995.

iv. *Special Protection Systems Criteria*, NPCC Document A-11; Northeast Power Coordinating Council, November 14, 2002.

2. Transmission Interfaces

Given Nova Scotia's geographic location, interconnection with other transmission systems is provided by a single interface with New Brunswick, although there are three transmission lines crossing the NS-NB border (one 345kV and two 138kV lines). From the perspective of NS-NB transfer capability, there is a single 345kV line in parallel with a single 138kV line, since the two 138kV lines merge into a single 138kV line at Springhill Nova Scotia.

It may be necessary to calculate ATC/TTC on internal interfaces as a means of managing congestion.

3. General Outline for Evaluation of the ATC

As defined by NERC, ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of Existing Transmission Commitments (ETC) (which includes retail customer service), less the Capacity Benefit Margin (CBM).

Since the Maritimes Area is radially connected to the Eastern Interconnection, and Nova Scotia is radially connected to the New Brunswick system, the calculation of ATC does not involve "parallel path flows". However, the NS-NB interconnection capability is dependent on a number of operational considerations that introduce uncertainty into the value of ATC for long-term reservation requests.

The determination of ATC and TTC requires the cooperation of the transmission providers on each side of the interconnection. NSPI and NB Power must agree on the limiting factor to establish the capacity of the interconnection in each direction. The NS-NB interconnection is limited by thermal equipment ratings and system stability for the export limit, and thermal, voltage, and stability ratings for the import limit. The interconnection capability relies heavily on the design and operation of Special Protection Systems, as defined by NPCC. Import capability is a function of the power that can be reliably delivered to the interface via the NB Power Transmission System, and the power that can reliably received into Nova Scotia. The NB Power Transmission Tariff highlights the methodology used to determine the former quantity. It should be noted that the NB Power transmission system has “simultaneous transfer limits”, which means that they cannot support simultaneous transfers on multiple interfaces. The simultaneous transfers on the following interfaces impact the NS-NB transfer limits:

- New Brunswick – New England interface
- New Brunswick – Prince Edward Island interface

Load flow base cases for winter peak and summer conditions are used in the determination of seasonal and long-term TTC and ATC values. For the winter case, an in-province forecasted peak load is modeled. In the summer case, in-province forecasted load is modeled on the basis of residential/commercial load at 60% of winter peak and large industrial at 100% of winter peak. All transmission facilities are assumed to be in-service and “normal” generation dispatch patterns are modeled.

Studies are then conducted to determine the TTC values under all possible combinations of transactions as explained in Section 4. The interface TRM and the CBM are determined using the principles given in Sections 5 and 6 respectively. Firm ATC and non-firm ATC values are calculated using the set of equations given in Sections 7 and 8 respectively.

4. Procedure for Calculating TTC

Based on load flow and stability studies, normal and first contingency scenarios are analyzed to determine the TTC of each interface independent of transactions on the other interfaces. The non-simultaneous TTC value for a given interface is defined as the lowest of the transfer limits defined by:

<u>Thermal Limit:</u> This is based on the most restrictive element in the transfer path (including internal Nova Scotia transmission) under normal or first contingency scenarios. Normal summer and winter thermal ratings are used under non-contingency scenarios. Emergency ratings are used for single contingency scenarios.

<u>Voltage Limit:</u> Network voltage will be kept in the range from 0.95 to 1.05 per unit for pre-contingency conditions, and between 0.90 and 1.07 per unit following single contingencies (10 minutes following the contingency for automatic tap changer operation).

<u>Stability Limit:</u> This limit is reached when further increase of a particular TTC results in system instability during normal conditions or single contingency scenarios.

<u>Frequency Limits:</u> If the Nova Scotia transmission system becomes isolated while importing power, frequency will decline until the load and generation balance is restored. This may require the activation of underfrequency load shedding (UFLS) in conjunction with generator governor response. The converse is true when exporting power, but limits on overfrequency are based on adverse impacts on generation. Frequency excursions for a single contingency must be maintained between 59.3 Hz and 61 Hz to avoid disruption to firm load or generating units.

NSPI uses a number of Special Protection Systems (SPS's), designed according to NPCC guidelines, to enhance the transfer limits between NSPI and NB Power. Whenever applicable, the SPS's are identified and reviewed as a part of the TTC calculations.

5. Procedure for Calculating Transmission Reliability Margin (TRM)

TRM for the NS-NB interface are determined on the basis of maintaining adequate Operating Margin, including Reserve Pickup Margin (such as reserve sharing), and to cover uncertainties within Nova Scotia and neighboring systems. Therefore, coordination with the concerned utilities is carried out in order to arrive at TRM values that produce a set of commercially viable and reliable ATC values. The TRM values are posted on OASIS, and are used in the calculations to arrive at the ATC values. In some cases no TRM is applied because the interface is protected by SPS action.

6. Procedure for Evaluation of the Capacity Benefit Margin (CBM)

Adequacy planning for Nova Scotia is conducted in accordance with the NPCC A-2 Criteria (Basic Criteria for Design and Operation of Interconnected Power Systems). The NSPI system is designed under the assumption that CBM is applied to the NS-NB interconnection capability. Long-term reservations must respect this margin. CBM is applicable to import capacity only.

7. Procedure for Calculating the Firm ATC Values

The firm ATC value for a given interface, in a specific direction, is evaluated as follows:

1) Determine the TTC value for this interface (taking into consideration any firm simultaneous transactions on other interfaces that impact the limit of this interface).

2) List all firm transmission reservations on the given interface, and calculate the total firm transmission reservation.

3) Determine the TRM and CBM values for this interface.

4) Firm ATC = TTC – TRM – CBM – Total Firm Transmission Reservations (all terms of the ATC equation are directional).

8. Procedure for Calculating the Non-Firm ATC

The non-firm ATC value for a given interface, in a given direction, is evaluated using different equations in the operating and planning horizons, as follows:

Operating Horizon: Takes into consideration transmission schedules.

1) List all Firm Scheduled Services on the given interface, and calculate the net schedule.

2) List all Non-firm Scheduled Services on the given interface, and calculate the net schedule.

3) Determine the TTC value for this interface (taking into consideration the firm and non-firm transmission schedules on other interfaces which impact the simultaneous limit of this interface).

4) Determine the TRM and CBM values and the portion (α) of the TRM that will not be available for any transactions, because of reliability concerns, where $0 \leq \alpha \leq 1$.

5) Non-firm ATC = TTC – α (TRM) – Non-firm Transmission Schedules – Firm Transmission Schedules (all terms of the ATC equation are directional with the exception of the "net" schedule).

Planning Horizon: Beyond the operating horizon and takes into consideration the transmission reservations.

1) List all Firm Transmission Reservations on the given interface, and calculate the total Firm Reservations.

2) List all Non-firm Transmission Reservations on the given interface, and calculate the total Non-firm Reservations.

3) Determine the TTC value for this interface (taking into consideration the firm and non-firm transmission reservations on other interfaces that impact the simultaneous TTC value for this interface).

4) Determine the TRM and CBM values and the portion of (β) of the TRM, that will not be available for any transactions, because of reliability concerns, where $0 \leq \beta \leq 1$.

5) Non-firm ATC = TTC – β (TRM) – Non-firm Transmission Reservations – Firm Transmission Reservations (all terms of the ATC equation are directional).

6) Long term ATC results do not include short-term equipment outages for maintenance and emergency repairs.

9. Updating Periods for the TTC and ATC

Because the TTC and ATC values depend on system conditions, actual schedules and planned transmission reservations, it is necessary to conduct periodic reviews to ensure that the posted values take into consideration the most recent information available to the Transmission Provider. Therefore updating of the TTC and ATC values will be done according to the following guidelines:

9.1 Updating the TTC Values:

The posted seasonal (summer and winter) TTC values for the NS-NB interface (and any future posted interface), under normal conditions, will be considered constant and valid for the entire season. These will be reviewed annually to ensure their validity for future years. Actual or forecast changes in system conditions will require a review and, if necessary, revision of the impacted TTC value(s).

9.2 Updating the TRM and CBM Values:

The TRM and CBM values will be reviewed, and updated as necessary, to account for any changes in system conditions that may require new margins. As previously indicated these values will not be posted on the OASIS, but will be used in the calculation of the ATC values.

9.3 Updating the ATC Values:

The Firm and Non-Firm ATC values for the operating and planning horizons are automatically calculated for the appropriate time frame, based on the following:

- Firm Scheduled Transmission Service,
- Non-Firm Scheduled Transmission Service,
- Firm Transmission Reservations,
- Non-Firm Transmission Reservations,
- TRM and CBM values,
- The magnitudes of α & β factors that may influence the amount of TRM and CBM that is available for non-firm transactions, and
- Individual and Simultaneous TTC values.

Appendix 4

SERC Supplement to the NERC I.E.1.S1 Planning Standard

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Measurements – I.E1.S1.M1, M3, & M4
System Adequacy and Security
Transfer Capability
Total and Available Transfer Capability

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NPCC CO-13 Whitepaper on Regional Methodology and Guidelines for Forecasting TTC and ATC

NPCC CO-13
Available Transfer Capability Working Group
September 20, 2005

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List of Attachments

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I. Introduction / Purpose

A. History

The Southeastern Electric Reliability Council (SERC), along with other Regions of the North American Electric Reliability Council (NERC), has responded to NERC initiatives to improve system security. These initiatives include the Security Process Task Force's (SPTF) recommendations and the NERC Security Coordination Subcommittee's (SCS) *Security Coordinator Procedures* to establish Security Coordinators and implement improved data sharing and coordination among operating utilities. In addition, the SERC members are also complying with the Federal Energy Regulatory Commission's (FERC) Orders 889 and 889A.

In June 1996, the NERC Transmission Transfer Capability Task Force (TTCTF) published its document titled *Available Transfer Capability Definitions and Determination*, (the ATC Document). In this document, Available Transfer Capability (ATC) is defined as "a measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already committed uses." ATC for a Transmission Provider (TP), Control Area, Subregion, or Region is a commercial value; however, the coordination of ATC values among neighboring transmission systems has both commercial and security implications.

In August 1996, the SERC Engineering Committee (EC) charged the SERC Reliability Review Subcommittee (RRS) with preparing ATC Coordination Procedures for SERC. The purpose of the procedures is to describe, from a Regional perspective, 1) the methodology used by the SERC Transmission Providers to calculate Total Transfer Capability (TTC) and Available Transfer Capability (ATC), 2) the coordination of ATC information and issues, and 3) the posting of ATC values.

The RRS published the *SERC ATC Coordination Procedures* on March 28, 1997. That document established the framework and procedures necessary to coordinate those values. By coordinating ATC values, the SERC Transmission Providers accomplished the following goals:

- Ensured that all commercially viable transfer limits within SERC are identified and evaluated periodically regardless of their location

- Increased communication and coordination of ATC values among neighboring systems so that comparable information is available on paths that have the same source and destination. This communication provides consistency of information in the marketplace.

- Enhanced the sharing of information to facilitate the calculation of ATC and the increased utilization of the transmission system without degrading reliability.

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The SERC Region supports the six ATC principles found in the NERC ATC Document. The following procedures discuss SERC's commitment to meeting Principle #4 that states:

> "Regional or wide-area coordination is necessary to develop and post information that reasonably reflects the ATCs of the interconnected network. ATC calculations must use a regional or wide-area approach to capture the interactions of electric power flows among individual, subregional, regional, and multiregional systems."

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Toward that end, SERC established the SERC ATC Working Group on October 1, 1997. The focus of this group is to improve the coordination of ATC activities of the Transmission Providers within SERC and with neighboring systems.

The following procedures address compliance with the Regional measures contained in NERC I.E1 Planning Standards (Total and Available Transfer Capabilities).

Note: Definitions for some of the terms found in this document may be found in the Reference Document, the ATC Document, or in the NERC Glossary of Terms.

B. Executive Summary

The ATC calculation efforts in SERC are in accordance with the six principles for calculating and applying ATCs specified in the NERC ATC Document. The SERC ATC coordination procedures utilize a distributed ATC calculation methodology. This methodology requires each SERC Transmission Provider to determine ATC values for each of its interfaces with directly interconnected systems and on an as needed basis for other commercially viable paths across its system. The SERC Transmission Providers are also responsible for monitoring and assessing the condition of the facilities under their operational control to ensure that they are operated within the Transmission Provider's safety standards and reliability criteria, including NERC and SERC policies and guidelines. The results of the individual efforts are then coordinated and compared with neighboring systems to identify and recognize the most limiting facility to determine the appropriate wide-area TTC/ATC values within the Region.

The coordination of ATC values among the SERC Transmission Providers is a two-phase process. The first phase has been a manual coordination process. The SERC Transmission Providers directly exchange information to support the calculation of ATC values for transfers to and from directly connected neighboring transmission systems. This data exchange is used to explore discrepancies in ATC values if necessary. Similar arrangements are in place for neighboring Regions. Outside of the regularly scheduled exchange of ATC data, the SERC Transmission Providers utilize the following tools:

- the NERC Security Coordination Information System (SCIS)
- the NERC System Data Exchange (SDX)
- the NERC Interchange Distribution Calculator (IDC)
- the NERC Power Transfer Distribution Factor (PTDF) viewer
- the NERC ISN

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These tools are necessary for the Transmission Providers to properly assess when the operation of the system has significantly impacted the ATC values. When these impacts have been identified, the SERC Transmission Providers notify each other and other Regions as soon as practicable.

The Transmission Providers in SERC participate in quarterly "OASIS Support Studies." These studies perform two-party non-simultaneous transfer capability assessments for the purposes of producing TTC values that may be used by Transmission Providers to derive seasonal and

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ultimately monthly ATC values. The time frame covered by these assessments is for the next five seasons (approximately eighteen months). The first of these studies was completed on schedule at the end of May, 1998. These studies ensure that all SERC Transmission Providers have coordinated TTC values, and through coordination, ATC values through the operational planning horizon.

For coordination in the Operating Horizon, a conference call is held within SERC every morning at 4:00 AM EPT. This conference call is designed to exchange data and usually has representation from each subregion. Data regarding and pertaining to TTC, ATC, limiting facilities and generation and transmission outages is shared. In addition, a SERC Security Coordinator conference call is held daily during peak demand periods and as needed (at least weekly) during lower demand periods. The emphasis of these calls is system security and the ability of each subregion to transmit power to other subregions.

In addition to the regularly scheduled conference call, SERC Control Area Operators are constantly in communication with each other and with other regions to ensure that security concerns and issues are made known and recognized. As new constraints are identified, these constraints are communicated and recognized through the determination and posting of TTC/ATC.

The second phase of the SERC ATC coordination process will be to use automated procedures to compare ATC values. SERC has considered the automated exchange of TTC and/or ATC values; however, the SERC ATC Working Group still does not believe that the tools allow for an automated comparison/coordination of values to occur at this time. The reservation and scheduling process for the use of the transmission system is not yet automated. Until this occurs and until a comparison tool can be developed to detect disparities in the transmission reservations and energy schedules, the automated comparison of ATC and TTC values will be at best problematic. However, SERC is committed to coordinate ATC and TTC values manually including the daily exchange of information. SERC has also committed to share information with other regions and is currently exchanging data with ECAR, FRCC, MAAC, MAIN, MAPP and SPP. In addition as automation of data exchange proves to be effective, consistent and with minimal problems, SERC will participate in that process toward achieving the goal of hourly coordination.

SERC will periodically review and modify this document as operating experience is gained and additional coordination needs are identified. It is necessary for the SERC ATC Coordination Procedures to evolve as the industry introduces new tools and as enhancements are made to the OASIS. It is also recommended that the SERC ATC Working Group continue to modify the document as improvements are recognized and can be incorporated into the procedures. The members of SERC are communicating and cooperating with ECAR, FRCC, MAAC, MAIN, MAPP and SPP in joint efforts to coordinate ATC.

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C. Introduction

The North American Electric Reliability Council (NERC) Transmission Transfer Capability Task Force (TTCTF) has published two documents that define transmission transfer capability and provide the basis for its calculation. The first document is *Transmission Transfer Capability: A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems*, (the Reference Document) which was published in May 1995. This document provides background and examples for calculating both incremental and total transfer capabilities under various conditions in the Eastern, ERCOT, and Western Interconnections. The second NERC document, *Available Transfer Capability Definitions and Determination: A framework for determining available transfer capabilities of the interconnected transmission networks for a commercially viable electricity market,* (the ATC Document), was published in June 1996 and responds to the need for Transmission Providers to comply with Federal Energy Regulatory Commission (FERC) initiatives.

When the NERC Board of Trustees accepted the ATC Document, it also approved three recommendations from the Task Force. These recommendations are as follows:

1. All Regions (or Sub-regions) should develop procedures for the determination and posting of available transfer capabilities and the allocation of transmission services (including reservations and scheduling), taking into account the ATC Principles in the Task Force's report.

2. NERC Planning and Operating Policies need to be reviewed and modified, as appropriate, to address the reservations and scheduling of transmission services recognizing the interdependent characteristics of the interconnected networks and the actual use that will be made of the networks for electric power transfers.

3. A NERC ATC Implementation Group should be formed to monitor and review the procedures developed by the Regions (or Sub-regions) for determining ATC to ensure that they are in concert with the ATC Principles in this report. All Regions (or Sub-regions) are expected to develop and submit such procedures and implementation plans to this NERC ATC group by January 1, 1997.

In response to these recommendations, the SERC Engineering Committee (EC) charged the SERC Reliability Review Subcommittee (RRS) with the task of developing ATC coordination procedures within the SERC Region and with Regions adjacent to SERC. The SERC EC later commissioned the SERC ATC Working Group to implement these procedures and to revise them as necessary.

Note: Definitions for some of the terms found in this document may be found in the Reference Document, the ATC Document, or in the NERC Glossary of Terms.

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II. Principles

A. NERC

The ATC calculation efforts in SERC will be in accordance with the six principles for calculating and applying ATCs specified in the NERC ATC Document as follows:

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

2. ATC calculations must recognize 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 transfers across the interconnected transmission 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 reasonably reflects the ATCs of the interconnected network.

5. ATC calculations must conform to NERC, Sub-regional, 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.

B. SERC

In addition to the NERC principles, SERC will adhere to the following principles:

1. ATC values will not be used by SERC as a reliability assessment or as an indication of system security.

2. SERC is responsible for coordinating reliability assessment within the region. Transfer capability assessments will continue to be performed by SERC Transmission Providers in accordance with the principles contained in the Reference Document. These transfer capability assessments are performed by the individual Transmission Provider or in joint studies as prescribed in joint reliability coordination agreements.

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3. Each SERC Transmission Provider will continue to have the responsibility to monitor and assess the facilities under its operational control to ensure that they are operated within the Transmission Provider's safety standards and reliability criteria including NERC and SERC policies and guidelines.

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4. Each SERC Transmission Provider has the responsibility to evaluate and quantify TTCs/ATCs as limited by facilities or conditions under its operational control.

5. Each SERC Transmission Provider will determine ATC values for each of its interfaces with directly interconnected systems and on an as needed basis for commercially viable paths across its system.

6. SERC members will cooperate with adjacent Regions to accomplish coordination of ATC procedures on an interregional basis.

7. Each SERC Transmission Provider will consider to the extent possible ultimate source, ultimate sink, point of delivery (POD), and point of receipt (POR) when evaluating transmission service requests.

The SERC ATC Coordination procedures and principles will continue to evolve as the OASIS and associated processes and procedures mature. All SERC members will continue to be provided an opportunity to participate in the future development and modification of these procedures.

III. SERC ATC Calculation Considerations

The following considerations will be used by SERC Transmission Providers to determine ATC values to be posted to the OASIS[1]. The ATC calculations are defined by SERC for the following three discrete horizons: operating, operational planning and planning.

A. General

The determination of ATCs will require knowledge of the most up-to-date transmission reservations, scheduled interchange transactions, TRMs, CBMs, projected generation dispatches, ongoing generation and transmission forced/planned/scheduled outages, load projections, and system topology. It is important that ATC values be calculated using a consistent methodology and frequency to provide a compatible evaluation process and to ensure the ATC values reasonably reflect the available transfer capability within SERC.

The Transmission Providers in SERC will derive transfer capability values using on-line and off-line power flow models to determine TTC and ATC that adjust for TRM, CBM, known schedules and reservations and any critical system or interregional constraints. Each Transmission Provider is responsible for determining the appropriate values for TRM and CBM for their control area on each interface in accordance with SERC's *Procedures for Transmission Capability Margins*.

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[1] The development of SERC OASIS nodes was implemented in an expedient manner to comply with the FERC Order 889. As a result the following nodes have been established: MAIN (Entergy/TVA), Southern (GTC/ MEAG), and VACAR.

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B. Guidelines

The following guidelines are to be used for the determination of TTC and ATC:

1. **Dispatch Methodology** - The dispatch methodology used for studies is based on an "emergency demand" scenario. In this scenario, an emergency situation is simulated in which critical generating facilities within one system are unexpectedly outaged, causing that system to request backup power from a neighboring system. The neighboring system, in response to the request, increases its dispatch to a new level in order to meet the importing system's deficiency in addition to its own generation requirements. Therefore, when modeling a transfer, the exporting system increases generation according to economics and operational requirements. The importing system, on the other hand, reduces generation at certain plants in order to represent a pessimistic, but realistic emergency transfer scenario. For the exporting system, increased generation should be represented at actual (physical) generation locations and should reflect the most reasonable expectation of the units on line and generation level. For the importing system, the lowered generation dispatch should be modeled at actual (physical) generating locations.

2. **Contingency Criteria** - The transmission system must be able to sustain at least a single contingency. More stringent local contingency criteria may be used to determine ATC values, but those criteria must be documented, noted in relation to the ATC/TTC being posted, and included with the Transmission Provider's FERC Form 715 filing.

3. **Transfer limits** - The determination of thermal, voltage and stability limits to transfer are the responsibility of the individual Provider.

4. **Maximum Practical TTC Values** - Posted TTC values will not exceed the level at which they were tested. The TTC could be re-evaluated if commercial activity on that particular interface indicated a need. The maximum TTC value to be used in the ATC calculation is the lesser of the contract path capacity on a posted path or the calculated FCTTC value.

5. **Exports from Generation Limited Areas** - To obtain a realistic test level for exports when a system is limited by available generation, it is permissible to reduce load in the exporting system up to 10 percent. Special circumstances may dictate a load reduction greater than this, but it should be done with care. It is also permissible to commit units that were not on line in the base case. Obtaining additional resources from systems "behind" the exporting area should only be done as a last resort in order to produce commercially viable TTC values and should be avoided altogether unless it can be shown that using such resources does not unrealistically skew the results for the transfer being studied.

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6. **ATC Calculation Frequency** - The ATC calculation will be performed and updated in accordance with FERC requirements.

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7. **Planned / Scheduled / Forced Outage Data** - SERC Transmission Providers should make available and incorporate information on outages of transmission facilities and generation units for the calculation of TTCs and ATCs.

8. **Reservations and Schedules for Service included in Base Case Data** - SERC Transmission Providers should include in the base case appropriate reservations and/or schedules. Coordinated interchange schedules/reservations are included in the MMWG, VST Databank, and VAST OASIS Support Study cases. As appropriate, those interchange schedules included vary with loading levels (e.g., peak, shoulder, light load) and with season. For ATC/TTC or other studies, partial path reservations may be included in individual TP's internal cases.

9. **System Load** - The load in the power flow model should be representative of the system conditions being modeled. The MMWG and VST Databank base case libraries include power flow models with the following system loads: Summer Peak, Winter Peak, Light Load, Shoulder Peak, Fall Peak, and Spring Peak.

   Load distribution should be considered based on historical and forecast load data. To the extent practical, load in external areas should be adjusted to reflect the system conditions being modeled. As appropriate, demand-side resources should generally include consistent program ratings and seasonal variations. Availability and contractual arrangements must also be considered. If an approved operating procedure utilizes a load shedding scheme, this data must be included for contingency analyses.

10. **Interchange** - Interchange in the power flow model should be representative of the system conditions being studied. In general, firm contract transactions should be modeled in planning horizon studies, while operating horizon studies should attempt to model all scheduled and reserved transactions.

11. **Facility Ratings** - Facility ratings in the power flow model will be based on summer or winter peak ambient conditions. Adjustments may be made to critical facility thermal ratings to account for expected weather during conditions under study. Ratings applied in the determination of TTC should be contingency-based (e.g. emergency) ratings.

12. **Response Factor Cutoffs -** A facility should generally have a transfer response greater than or equal to three percent to be identified as a transfer limiting facility. Limiting facilities having less than a three percent response to transfer are not normally reported unless the owner of the facility deems the limiting facility significant. Engineering judgment should be used in deciding if lower response facilities should be recognized as transfer limiting facilities.

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13. **Operating Procedures** - Operating procedures that have been identified to relieve loading problems should be considered in the transfer capability analysis according to

NERC guidelines. However, the implementation of an operating procedure normally requires the removal of a transmission facility from service or may involve the redispatch of generation to relieve the overloaded facility. This will impact the reliability and

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economics of system operations. Under certain system conditions and configurations, operating procedures may be reserved for emergency needs only. The recognition of operating procedures should be coordinated between Transmission Providers.

14. **Netting of Schedules/Reservations –** The following guidelines are used by SERC Transmission Providers and Control Areas when evaluating whether or not to net energy schedules/reservations:

    a. Abide by NERC Operating Policies

    b. Consider the effects of existing transmission reservations that are included in the base case of power flow studies for TTC and ATC determination when evaluating new transmission service requests

    c. Source and Sink information is required for evaluation and approval of requests for transmission service.

    d. When submitting Interchange transactions to the Control Areas, all PSEs should complete the NERC Interchange Transaction Tag with the correct source and sink information.

    e. Transmission Providers should not net energy schedules in excess of what Control Area operators can manage in a real-time environment.

    f. The Transmission Provider in conjunction with the Control Area operators is accountable for establishing the linkage between netted energy schedules in order to ensure reliability during curtailments.

    g. Energy schedules beyond the next day may be netted at the discretion of the Transmission Provider.

    h. The netting of energy schedules by the SERC TPs should not increase the availability of firm transmission service on the Provider's system.

    i. Consideration for netting of energy schedules should be given as to whether a scheduling limitation is based on Total Transfer Capability or the total capacity of facilities.

C. Common Base Assumptions

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Operating Horizon - The operating horizon typically varies in time from next hour to 31 days. Within this horizon, ATC values are calculated for various time periods on a continuous basis. Both off-line and on-line power flow models as available will be used by SERC Transmission

Providers to perform transfer studies and to calculate TTC and ATC values for these time periods. Each SERC Transmission Provider will share near-real-time information regarding generation outages, changes in transmission topology, reservations, and schedules.

Operational Planning Horizon - The operational planning horizon typically is from month two through month thirteen. Seasonal power flow models will be developed by the appropriate reliability study groups and subsequently updated with more current assumptions as needed. SERC Transmission Providers will then use these models as a starting point to calculate TTC values. The SERC Transmission Providers can use these TTC values to calculate monthly ATC values. Each SERC Transmission Provider will be responsible for calculating the projected ATC values using these and other study results.

Planning Horizon - The planning horizon is typically from one to ten years. The appropriate reliability study groups are responsible for preparing future year power flow models for a variety of purposes. These models can be used by the SERC Transmission Providers to perform transfer studies from which TTC and ATC values can be derived.

D. Transmission Provider Calculation Requirements

Each SERC Transmission Provider will calculate non-firm and firm ATC and TTC values, as limited by the individual Transmission Providers' own facilities for directly interconnected systems and for commercially viable paths as requested. These values will be determined using conventional linear analysis, AC power flow analysis or other industry accepted methodologies.

In addition to its own facilities the Transmission Provider should also consider transmission facilities in other systems as warranted by experience and good engineering judgment, consistent with NERC guidelines.

E. Review Procedures

The SERC ATC Working Group, as the Reliability Review Group for the I.E Standards, will annually audit member Transmission Providers to ensure compliance with these *SERC ATC Coordination Procedures* and the NERC Planning Standards. Results of the audits will be made available to NERC on request.

F. Transmission User Complaint/Question Forum

The SERC ATC Working Group has developed a procedure for transmission users of the various OASIS sites within SERC to submit questions or concerns directly to SERC transmission providers. It is available at the SERC web site, www.serc1.org. These questions/concerns may be related to actual TTC/ATC calculations or methodology. Transmission users may also submit questions to those transmission providers not required to operate an OASIS site. The user may choose the transmission provider from the “drop-down” list to which the question/concern is being addressed. The user’s question/concern will be forwarded to a designated contact for the transmission provider. The name and phone number of the contact is provided. A copy of the submittal will be sent to the Co-Chairs of the ATCWG and to the SERC Staff Representative to the ATCWG.

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Questions/concerns regarding particular TTC/ATC values or methodology should be limited to the previous thirty days. The transmission provider should respond within 30 days to the question/concern via e-mail. Additionally, the question/concern will be reviewed at the following ATCWG meeting if deemed appropriate by the Co-Chairs or if requested by the transmission

user. The transmission user may attend a SERC ATCWG meeting if the response of the transmission provider is deemed unsatisfactory. If the transmission user desires further recourse, the Dispute Resolution Procedures, as detailed in Section VI.D. of this document, can be pursued.

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IV. SERC ATC Coordination Procedures

SERC Transmission Providers are actively engaged in the coordination of TTC and ATC information and values. The methodology used to coordinate these data is divided into the following categories:

A. The Exchange of Information and Data
B. Joint Studies of Transmission Transfer Capability and System Performance
C. The Direct Comparison of TTC, ATC, TRM, CBM and Reservation Values
D. Dispute Resolution Procedures

A. The Exchange of Information and Data

Entities within SERC are currently exchanging data in a wide variety of formats and venues. For example, SERC exchanges data at the Security Coordinator, Control Area and Transmission Provider levels. These data exchanges are described below.

All SERC Security Coordinators are supplying information for and using the following NERC tools: the Security Coordinator Information System (SCIS), the Interchange Distribution Calculator (IDC),the Power Transfer Distribution Factor (PTDF) Viewer and System Data Exchange (SDX). The Security Coordinators are also communicating problems, adequacy of reserves, transmission and generation outages and other information as specified by the Security Coordinator Functions contained in NERC Policy 9 - Security Coordinator Procedures.

SERC Control Areas are entering schedules into the IDC and communicating problems to the appropriate Security Coordinator. In addition, all SERC Control Areas are making EMS data available to and are planning to use the NERC Interregional Security Network (ISN) to evaluate system performance and to assess system security. Also, the Control Areas are supplying data for SDX and updates to the IDC data base.

The SERC Transmission Providers are providing transmission reservations, margins, capability and other information on their OASIS sites. SERC is also communicating applicable transmission and generation data on the NERC System Data Exchange (SDX). In addition, as longer-term (generally greater than a month) transmission service is requested, certain SERC Transmission Providers are communicating and coordinating information with neighboring providers prior to accepting and confirming the reservation.

In addition to the data exchanges described above, SERC is active in the development of Power Flow Base Cases as follows:

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VACAR-Southern-TVA-Entergy (VST) Data Bank Base Case Development: In June of each year, representatives from the reliability agreements within the SERC Region meet and exchange information for the purpose of updating a series of power flow base cases that model various seasons for the next ten years. The cases that are created utilize the previous year's NERC Multi-regional Modeling Working Group (MMWG) Base Cases for external Region representation. The result of this base case development process is threefold:

1. Prepared cases are used for regional studies that fulfill the requirements established by various reliability agreements among Transmission Providers within SERC (VACAR-Southern, Southern-TVA, TVA-OPC, etc.).

2. Provides access to Transmission Providers and interested parties to models of the system. These models allow individual entities to perform studies whereby they can analyze and assess the capability of the system for reliability, security and commercial reasons.

3. Provides the basis for SERC's update to the MMWG Base Case development process.

In addition to the VST Databank update and MMWG Base Case development processes, SERC Transmission Providers, Control Areas and Security Coordinators are sharing information and communicating a great deal of information within and external to the region. A great deal of information is shared as the result of joint studies of transmission transfer capability and system performance.

B. Joint Studies of Transmission Transfer Capability and System Performance

Twice a year, the Transmission Providers within SERC plus AEP perform transmission studies to assess the strength of the transmission grid. These studies are performed under the auspices of the reliability agreements between the subregions of SERC (VACAR, Southern, TVA and Entergy) and include transfer capability analyses for the upcoming peak season. These studies, called "VAST Reliability Studies", examine all two-party and subregional transfers within SERC, and include AEP. Each of these studies is a coordinated effort involving the sharing of data and agreement on study assumptions.

The results of the VAST Reliability Studies are reviewed and agreed upon, and all parties use them to identify key contingency and limiting transmission elements for further analyses.

In addition to the VAST Reliability Studies, the VACAR subregion participates in the VEM (VACAR-ECAR-MAAC) Inter-Regional studies and the Entergy and TVA subregions participates in the MAIN Inter-Regional studies that are also performed twice a year. Additionally, the Southern subregion routinely participates in joint studies with the FRCC region to evaluate system performance on the SERC – FRCC interface. SERC member participation in these Inter-regional reliability studies ensures that there is better data coordination between regions and provides consistency between the studies performed in SERC and other regions.

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1. OASIS Support Studies (Operational Planning Horizon)

The VST study organization within SERC began a process in the summer of 1996 to conduct joint studies in support of member requirements for posting Available Transfer Capability on the OASIS. These studies are currently performed on a quarterly basis, and focus on providing study participants with supporting data for posting commercial transmission capability in the operational planning horizon (months 2-13). The time frame covered by these assessments is for the next five seasons (approximately eighteen months), producing TTC values that may be used by Transmission Providers to derive seasonal and ultimately monthly ATC values. The participants in this process work jointly to develop base case power flow models for projected seasonal peak conditions (spring, summer, fall, winter);

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perform linear transfer analysis using a common set of parameters; and, jointly establish initial TTC values for various transfers among the participants.

Each Transmission Provider in SERC is responsible for the calculation, documentation and posting of its own TTC and ATC values. SERC Transmission Providers use the studies listed above as guidelines for these calculations. Assumptions and data continue to evolve over time, and thus so do the values that are calculated by each provider. Using the study processes, the results of joint and individual study efforts will continue to be compared to identify the most limiting facility to determine the appropriate wide-area FCITC/TTC values within the Region. In addition, the SERC Transmission Providers have shared the methodology and values that are being used for the calculation of transmission margins (TRM and CBM) and are considered in the calculation and posting of ATC with adjoining systems.

2. OASIS Support Study Participants

Entergy Subregion - Entergy and Associated Electric Cooperative, Inc.
Southern Subregion - Southern Company and Georgia Transmission Corporation
TVA Subregion - Tennessee Valley Authority
VACAR Subregion - Carolina Power & Light, Duke Energy, South Carolina Electric & Gas, South Carolina Public Service Authority, and Dominion Virginia Power

C. The Direct Comparison of TTC, ATC, TRM, CBM and Reservation Values

Currently, a conference call is held within SERC every morning at 4:00 AM EPT. This conference call is a data exchange and usually has representation from each subregion. Data regarding and pertaining to TTC, ATC, limiting facilities and generation and transmission outages is shared. In addition, a SERC Security Coordinator conference call is held daily during peak demand periods and as needed (at least weekly) during lower load periods. The emphasis of these calls is system security and the ability of each subregion to transmit power to other subregions.

In addition to the regularly scheduled conference call, SERC Control Area Operators are constantly in communication with each other and with other regions to ensure that security concerns and issues are made known and recognized. As new constraints are identified, these constraints are communicated and recognized through the determination and posting of ATC.

As stated, studies within SERC look at all two-party, non-simultaneous transfers within the region and limit firm transactions to stated limits or analysis of power flow cases. These studies are performed in an operational planning horizon and consider each Transmission Provider's CBM and TRM reservations. In addition, the Transmission Providers within SERC are currently exchanging information with other Transmission Providers for the timely and accurate calculation of TTC and ATC values. This information is updated whenever significant changes occur on the network that may have an impact on TTC/ATC values. In an effort to coordinate data for the

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determination of TTC/ATC values, a reservation-sharing process has been implemented. The SERC ftp site functions as a centralized SERC site for reservation sharing to all transmission customers.

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SERC implemented a manual coordination process for monthly TTC and ATC values for the Operating Planning Horizon on May 13, 1998. This coordination is accomplished via joint studies and the direct exchange and comparison of TTC, ATC, TRM, CBM and transmission reservation values for agreed to transmission paths. Through this process, it is anticipated that data (including limiting facility data) will be shared with neighboring regions (SPP, FRCC, MAIN, ECAR MAPP and MAAC). The SERC ATC Working Group believes that these efforts, when in place, will provide for more accurate and consistent TTC values to be calculated throughout the SERC and other regions.

Interregional Coordination

SERC is participating on an Interregional Coordination (IRC) group made up of representatives from MAPP, MAIN, SPP, SERC, and ECAR. This group has identified the information needed to coordinate data exchange and OASIS postings. A matrix has been developed to identify the areas where data is available in the Regions for coordination. From this document, the group will identify areas where additional coordination is needed and secure buy-in from the members.

SERC (Southern) - FRCC Interface

All SERC Transmission Providers participate in the SDX system, which provides system data for use in ATC calculation base cases. In addition, there is an automated exchange of data between SERC and FRCC from the real-time security system that occurs several times per hour. The coordinated TTCs are calculated for the summer and winter peak seasons and posted.

SERC (VACAR) - ECAR Interface

All SERC Transmission Providers and ECAR Transmission Providers participate in the SDX system, which provides system data for use in ATC calculation. Virginia Power is also coordinating monthly ATCs and TTCs on its interfaces with AEP and AP.

SERC (VACAR) - MAAC Interface

MAAC and all SERC Transmission Providers participate in the SDX system, which provides system data for use in ATC calculation. Virginia Power also makes its monthly ATC and TTC values available to PJM, but differences in calculation and posting methodology preclude direct coordination of TTCs and ATCs on the VP-PJM interface.

SERC (TVA) – MAIN Interface

MAIN and all SERC Transmission Providers participate in the SDX system, which provides system data for use in ATC calculation. TVA also makes its ATC and TTC values available to MAIN, but differences in calculation and posting methodology preclude direct coordination of TTCs and ATCs on the TVA-MAIN interface. In addition, TVA is a participant in the IRC process.

SERC (Entergy) – SPP Interface

SPP and all SERC Transmission Providers participate in the SDX system, which provides system data for use in ATC calculation. In addition, Entergy also makes its ATC and TTC values available to SPP, but differences in calculation and posting methodology preclude direct coordination of TTCs and ATCs on the Entergy-SPP interface.

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SERC (Entergy/Associated Electric Cooperative, Incorporated) – MAPP Interface

All SERC Transmission Providers participate in the SDX system, which provides system data for use in ATC calculation. Entergy also makes its ATC and TTC values available to

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MAPP, but differences in calculation and posting methodology preclude direct coordination of TTCs and ATCs on the Entergy-MAPP interface.

D. Dispute Resolution Procedures

The responsibility for dispute resolution resides with the Transmission Provider. However, if the dispute cannot be resolved at this level, it will be referred to a contract or tariff dispute resolution process or the appropriate SERC Dispute Resolution Process[2].

The SERC Dispute Resolution Processes were established to resolve, on a timely basis, issues of actual or perceived non-compliance or disagreement regarding matters within or between SERC member systems, between SERC systems and non-SERC systems or adjacent Regions, and involving SERC Sub-regions and non-members of SERC. Disputes between SERC and other regions will be handled by the Regions where applicable; otherwise, the disputes will be referred to the NERC Dispute Resolution Process. In the interim, if two Transmission Providers are calculating different TTC values for the same path, the resolution is to use the lesser of the TTC values on that path.

V. Future Considerations

The SERC Transmission Providers should continue to pursue the automated exchange of information regarding transmission reservations, scheduled interchange transactions, TRM, CBM, projected generation dispatches, generation and transmission planned/scheduled outages, ongoing generation and transmission forced and scheduled outages, load projections, and system topology. Using this information will improve the accuracy and consistency of the individual TTC and ATC calculations.

SERC will periodically review and modify this document as operating experience is gained and additional coordination needs are identified. It is necessary for the SERC ATC coordination procedures to evolve as the industry introduces new tools and as enhancements are made to OASIS. It is also recommended that the SERC ATCWG continue to modify the document as improvements are recognized and can be incorporated into the procedures. Members of SERC are communicating and cooperating with ECAR, FRCC, MAAC, MAIN, MAPP and SPP in joint efforts to coordinate ATC.

The NERC Board of Trustees established a Transmission Reservation and Scheduling Task Force (TRSTF) to develop a process for the reservation of transmission services and the scheduling of energy transfers recognizing the actual use being made of the Interconnections. It is recognized that the separate interconnected networks (Eastern, Hydro-Quebec, Western, and ERCOT) have differing characteristics and, therefore, processes unique to each Interconnection may be appropriate. SERC will review and revise its Operating and Planning Policies, as appropriate, to address future changes developed by NERC.

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[2] Depending on the nature of the dispute, either the SERC EC Dispute Resolution Process or the SERC OC Dispute Resolution Process will be implemented.

The NERC Interregional Security Network (ISN) allows for the exchange of real-time operational data between control areas to enhance the security of the transmission network. This initiative provides additional information to enhance security analysis and may also increase the accuracy of near-term TTC and ATC values

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Brief Description Documentation and content of each Regional TTC and ATC methodology.

Section I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M1. Each Region, in conjunction with its members, shall develop and document a Regional TTC and ATC methodology. Certain systems that are not required to post ATC values are exempt from this Standard.

This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's TTC and ATC methodology shall (S1):

a) Include a narrative explaining how TTC and ATC values are determined.
b) Account for how the reservations and schedules for firm (non-recallable) and non-firm (recallable) transfers, both within and outside the transmission provider's system, are included.
c) Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations.
d) Describe how incomplete or so-called partial path transmission reservations are addressed. (Incomplete or partial path transmission reservations are those for which all transmission reservations necessary to complete the transmission path from ultimate source to ultimate sink are not identifiable due to differing reservation priorities, durations, or that the reservations have not all been made.)
e) Require that TTC and ATC values and posting within the current week be determined at least once per day, that daily TTC and ATC values and postings for day 8 through the first month be determined at least once per week, and that monthly TTC and ATC values and postings for months 2 through 13 be determined at least once per month.

f) Indicate the treatment and level of customer demands, including interruptible demands.
g) Specify how system conditions, limiting facilities, contingencies, transmission reservations, energy schedules, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used within the Region and with neighboring interconnected electric systems, including adjacent systems, subregions, and Regions. In addition, specify how this information is to be used to determine TTC and ATC values. If some data is not used, provide an explanation.
h) Describe how the assumptions for and the calculations of TTC and ATC values change over different time (such as hourly, daily, and monthly) horizons.
i) Describe the Region's practice on the netting of transmission reservations for purposes of TTC and ATC determination.

Each Regional TTC and ATC methodology shall address each of the items listed above and shall explain its use in determining TTC and ATC values.

The most recent version of the documentation of each Region's TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to
Regions.

Items to be Measured
Development and documentation of each Region's TTC and ATC methodology and the completeness of the content of each Regional TTC and ATC methodology.

Timeframe
Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance

Level 1
The Region's documented TTC and ATC methodology does not address one or two of the nine requirements for such documentation as listed above under Measurement M1.

Level 2
N/A

Level 3
N/A

Level 4
The Region's documented TTC and ATC methodology does not address three or more of the nine requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented TTC and ATC methodology.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Measurement M2 eliminated. Requirements included in Measurement M3.

Brief Description

Review of transmission provider TTC and ATC calculations and resulting values for compliance with the Regional TTC and ATC methodology.

Section

I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review periodically (at least annually) and ensure that the TTC and ATC calculations and resulting values of member transmission providers comply with the Regional TTC and ATC methodology, the NERC Planning Standards, and applicable Regional criteria. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

Applicable to

Regions.

Items to be Measured

Transmission provider TTC and ATC calculations and resulting values for compliance with the Regional TTC and ATC methodology.

Timeframe

Procedure on request (within 30 days).
Documentation of results of Regional reviews on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TTC and ATC methodology, as documented per Measurement I.E.1. S1, M1, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a TTC and ATC methodology consistency review of all transmission providers within its Region, or has not performed any such reviews on an annual basis.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description Regional procedure for input on TTC and ATC methodologies and values.

Section I. System Adequacy and Security
E. Transfer Capability
1. Total and Available Transfer Capabilities

Standards

S1. Each Region shall develop a methodology for calculating Total Transfer Capability (TTC) and Available Transfer Capability (ATC) that shall comply with the above NERC definitions for TTC and ATC, the NERC Planning Standards, and applicable Regional criteria.

Each Regional TTC and ATC methodology and the resulting TTC and ATC values shall be available to transmission users in the electricity market.

Measurement

M4. Each Region, in conjunction with its members, shall develop and document a procedure on how transmission users can input their concerns or questions regarding the TTC and ATC methodology and values of the transmission provider(s), and how these concerns or questions will be addressed. Documentation of the procedure shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market. (S1)

Each Region's procedure shall specify (S1):

a) The name, telephone number and email address of a contact person to whom concerns are to be addressed.
b) The amount of time it will take for a response.
c) The manner in which the response will be communicated (e.g., email, letter, telephone, etc.)
d) What recourse a customer has if the response is deemed unsatisfactory.

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Applicable to
Regions.

Items to be Measured
Regional procedure for receiving and addressing transmission user concerns on the TTC and ATC methodology and TTC and ATC values of member transmission providers.

Timeframe
Procedure available on a web site accessible by the Regions, NERC, and transmission users.

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region does not have a procedure available on an accessible web site, or the procedure does not provide the information necessary to complete the submittal of a comment, have it processed by the Region, and have an answer provided as indicated in the procedure.

Level 3
N/A.

Level 4
The Region has no procedure available.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

SERC Supplement to the NERC I.E.2.S1 & I.E.2.S2 Planning Standards

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Measurements – I.E2.S1.M1, M3, M4, & M5 and I.E2.S2.M6 & M8
System Adequacy and Security
Transfer Capability
Transfer Capability Margins

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Revision History

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Revision	Date	Comments
0	December 8, 1999	Initial issue of document
1	October 20, 2000	Document update
2	June 4, 2001	Document update
3	October 19, 2001	Document update
4	March 8, 2002	Re-formatted document

Responsible SERC Subgroup & Region Review Group

Available Transfer Capability Working Group (ATCWG)

Review and Re-Certification Requirements

This procedure will be reviewed every five years or as appropriate by the SERC ATCWG for possible revision. The existing or revised document will be re-certified and distributed to all members by the SERC Engineering Committee.

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List of Attachments

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I. Introduction / Purpose

In June of 1996, the North American Electric Reliability Council (NERC) approved a document entitled *"Available Transfer Capability Definitions and Determination"* as a framework for determining Available Transfer Capability (ATC) to satisfy both the Federal Energy Regulatory Commission (FERC) requirements and industry needs. In defining the components that make up ATC, a number of new terms were introduced. Among these terms were two transmission margins to recognize uncertainty inherent in the interconnected power system. These two margins are known as the Transmission Reliability Margin (TRM) and the Capacity Benefit Margin (CBM). During the past year SERC has identified a requirement to have a regional methodology for the determination of TRM and CBM. This requirement has been necessitated by the following events:

- The NERC Available Transfer Capability Working Group (ATCWG) performed a review of each of the ten region's ATC determination procedures and their compliance with NERC principles. The NERC ATCWG determined that Transmission Providers are not currently using a common philosophy with regard to the necessity of margins and they are not using a consistent methodology to calculate margins across the Interconnections. Because of this disparity and the desire to encourage a convergence of margin methodologies, the NERC ATCWG has published a revised set of definitions for TRM and CBM.

- The NERC ATCWG recommended that each region develop a region-wide methodology for the determination of transmission margins. In the SERC response to the NERC review of the SERC Region, SERC developed an action plan that included developing a regional methodology for determining TRM and CBM. Both the SERC ATCWG and the SERC Engineering Committee approved this action plan in June 1999.

- On September 27, 1999 the chairman of the NERC Adequacy Committee sent a letter to all ten Region Managers requesting a status report of regional methodologies for TRM and CBM including the key elements of the methodology being considered. In addition, the Region Managers are expected to provide completion and implementation dates for the regional methodologies.

- NERC is also developing Planning Standards that include standards on the determination of Transfer Capability. The draft standards identify the need to have regional methodologies for TRM and CBM determination and have those methodologies adhered to by Transmission Providers within the region.

- The FERC issued a ruling (Docket No. EL99-46-000) that directs Transmission Providers, working through NERC to complete the process to establish a standardized methodology for deriving CBM by the end of 1999.

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To meet the requirements of the SERC Action Plan, the NERC Planning Standards, and the FERC requirements, the SERC ATCWG has developed a set of procedures for TRM and CBM. The procedures are based on the definitions established by NERC and reflect the requirements established by the draft Planning Standard Templates and the FERC ruling on CBM.

The purpose of these procedures is to promote a common TRM and CBM methodology and to implement a consistent approach for their determination and application for the SERC Region. If approved, these procedures will serve as an instrument for ensuring that Transmission Providers within the SERC Region are compliant with the NERC Planning Standards as they relate to CBM and TRM.

II. Definitions

Capacity Benefit Margin (CBM)
The amount of firm transmission transfer capability preserved for Load Serving Entities (LSEs) on the host transmission system where their load is located, to enable access to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for a LSE 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 transmission capacity preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Transmission Reliability Margin (TRM)
The amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and its associated effects on ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change. All transmission system users benefit from the preservation of TRM by Transmission Providers.

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III. Requirements/Expectations

Capacity Benefit Margin

Unlike TRM, the direct beneficiaries of CBM can be identified. These beneficiaries are the LSEs that are network customers (including native load) of a host Transmission Provider. The benefit that LSEs receive from CBM is the sharing of installed capacity (planning) reserves elsewhere in the Interconnection, which translates into a reduced need for installed generating capacity and ultimately, lower rates for their customers. Generation reserve sharing programs that obligate entities to supply reserves as the result of an operating emergency should be accounted for in TRM instead of CBM.

Generally, the CBM is not a "real-time" margin that "exists" in the operating horizon, but is a margin that extends into the future. The amount of CBM to be applied is in the form of a continuum in which the CBM may be at a maximum amount in the longer term and a minimum level beginning with the operating horizon. This assumes that the uncertainty associated with generation availability decreases as the time horizon is reduced. In the operating horizon, generation capacity benefits, in the form of operating reserves, are considered part of the TRM. Since quick replacement of lost resources benefits the entire Interconnection, operating reserves, for the time period between the contingency event and the time the Control Area must replace the deficiency through other means, provides reliability benefits beyond the specific LSE being served from that resource and is not considered part of the CBM. Transmission capacity needed to accommodate generation reserves consistent with generation reliability criteria that are above the required operating reserve level may be included in CBM.

CBM benefits an identifiable set of transmission system users known as LSEs (including the native load of the host Transmission Provider). CBM is only to be preserved as an import quantity (a unidirectional quantity) on the system of the host Transmission Provider. In determining the amount of CBM to apply, the requirements of all customers entitled to its use must be taken into consideration. SERC Transmission Providers have the responsibility to determine CBM but must do so with the input of all LSEs entitled to a portion of the CBM.

CBM Calculation and Allocation

The methodology that each SERC LSE (including the native load of the host Transmission Provider) uses to derive their requirements for requesting CBM from SERC Transmission Providers must be documented and consistent with published planning criteria. A CBM request is considered consistent with published planning criteria if the same components that comprise the CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics, as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained.

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The Generation Reserve Requirement that the SERC LSEs use can be determined via either deterministic or probabilistic methods.

- ***Probabilistic Methodology*** — Probabilistic calculation methods, such as Loss of Load Probability, have inputs such as unit forced outages, maintenance outages, minimum downtimes, load forecasts, etc. A typical benchmark is a generation reserve level to achieve a probabilistic loss of load expectation of 0.1 day per year.
- ***Deterministic Methodology*** — Deterministic methods typically are centered on maintaining a specified reserve or capacity margin or may be based upon surviving the loss of the largest generating unit. Typical benchmarks for the determination methodology would be a multiple of the largest generation unit within the Transmission Provider's system.

Whether probabilistic or deterministic methods are used to determine the generation reserve requirement, the Transmission Provider must evaluate the criteria and apply it consistently to all LSEs. In some cases, it may be appropriate to apply both deterministic and probabilistic methods for the determination of generation reserve requirements, depending upon the time frame under consideration. For example, in the very near time frame, the degree of uncertainty associated with generating unit forced and maintenance outages should be low and deterministic methods for the calculation of generation reserve requirements may be applied. In this example, for the longer-term time frame, probabilistic methods may be applied due to the number of variables and the uncertainty associated with them.

The determination of CBM for an LSE is a three-step process:

1. The amount of additional external generating capacity necessary to achieve a target reliability level (e.g., 0.1 day / year loss of load expectation) must be determined.
2. The total amount of transmission transfer capability necessary to import the external generating reserve requirement must be determined from the amount of required external generating capacity (less the TRM component for operating reserves).
3. This total amount of transmission transfer capability must be allocated to the specific transmission system interfaces or paths over which the import power may flow.

These three steps can be accomplished either sequentially or simultaneously. Sequential determination often relies on deterministic rules. (For example, the needed external generating capacity might be set at the capacity of the largest internal plant, the total CBM might be set at two times that amount, and the allocation among three interfaces might be set as 60/20/20%, based upon historical experience). Simultaneous determination can be accomplished with a probabilistic model, which includes both generation and transmission representation.

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All loads connected to the Transmission Providers' system are included in the calculation and determination of the CBM requirement as it is the intention of LSEs within SERC to serve their respective load, including curtailable loads, connected to the Transmission Providers' system. Furthermore, curtailable contracts may have restrictions that may limit the duration of curtailment. All generation either directly or indirectly connected to the Transmission Providers' system that is used to serve the load directly connected to that system will be considered in the CBM requirement determination. These units are included in the determination of CBM because these generation resources are committed for the principal purpose of serving the LSEs' loads. Generation directly connected to the Transmission Providers' system but not committed to serve load on that system will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected. These units are not included because they can be committed to serve load on another system and, therefore, may not be available to serve load on the system for which the CBM requirement is being determined.

Regardless of the process used, the Transmission Provider must ensure and the SERC ATCWG must agree that:

a) The method used to arrive at the amount of external generation needed is consistent with applicable reliability criteria.
b) If the total transmission capacity reserved as CBM on all interfaces exceeds the external generation reserve requirement (less the TRM component for operating reserves), it is reasonable and justified.
c) The allocation of the total CBM to individual interfaces or source points is consistent with available external generation resources, known transmission limitations, and historical transfer patterns during actual emergency generating capacity deficiency events.

The allocation of CBM to the host Transmission Provider interface(s) must be based solely on the LSEs' generation reserve requirement and projected availability of outside sources, the strength of the transmission interfaces needed to import the CBM requirement allocation, and the historical availability. The preservation of CBM on the importing Transmission Provider's system does not ensure the availability of transmission transfer capability on other systems, but relies on the diversity of generation and transmission resources that may be available on the interconnection during a generation emergency of a particular host control area. Therefore, the availability of third party transmission transfer capability must be a consideration in the allocation of CBM.

CBM may be allocated to each Interconnection interface and subtracted from the calculated TTC. In so doing, the actual flow impacts of CBM reservations may not be taken into account. In some cases, it may be appropriate for the Transmission Provider to allocate CBM to each interface in such a manner that the sum of the allocations to all the interfaces exceeds the generation requirement used to determine the CBM. This is to recognize the low probability of all resources upon which dependency is projected being available simultaneously.

CBM may also be allocated to a transmission system by modeling the generation reserve requirements as base transfers and examining, via powerflow analysis, the impacts of the

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modeled generation reserve requirements upon the TTC of the path being studied. This method accounts for the predicted flow impacts of the CBM preservation.

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Use of CBM

CBM may be sold on a non-firm basis to all tariff customers including "through" customers. As with any margin, generation reserve requirement (and therefore the CBM) should be recalculated as conditions change or at a minimum, on an annual basis. If a change (increase or decease) in CBM on a particular path is prudent due to current or projected conditions, the host Transmission Provider (and/or the LSE) may change the CBM on the path provided that there is sufficient firm ATC on that path. If there is not sufficient firm ATC available, the host Transmission Provider (and/or the LSE) cannot unilaterally displace other existing firm uses of the interface.

The use of CBM "in advance" of the near-term horizon must be fully explained by the LSE. CBM is only to be used for capacity deficiency emergency conditions. The explicit planned use of CBM capacity far into the future is a contradiction of terms. The CBM is used only for the existing real time (or projected within hours) generation capacity deficiency. These conditions should not be driven purely by economic reasons, but rather must be based upon true emergency generation deficiencies. CBM should be invoked only after all other options available to the Load Serving Entity (short of shedding firm load) have been exhausted or should be consistent with the requirements of any applicable reserve sharing group.

Components that are not to be considered in the determination of CBM:

- **Single transmission and generator contingencies:** These components shall be included in the determination of TTC, provided the contingencies are consistent with appropriate published NERC, Regional, sub-regional, power pool, and individual system reliability criteria.
- **All known generation and transmission outages:** Known outages are to be incorporated into ATC calculations for both firm and non-firm transmission service.

SERC requirements for Transmission Providers to specify CBM:

- Transmission Providers shall document the calculation of the CBM component of ATC in accordance with applicable NERC Standards and SERC procedures.
- Transmission Providers shall update their CBM component of ATC at least once a year and post the values on the SERC site available to all users.
- Each Transmission Provider shall make the CBM determination and methodology publicly available in accordance with FERC requirements.
- The Transmission Provider must submit the CBM calculations to SERC so that the Region can confirm that the calculations are consistent with the Regional methodology.

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- Each Transmission Provider shall post any actual usage of CBM, except sales as non-firm transmission service. This posting may be after the fact. Any usage must be consistent with NERC Operating Policy 9B.
- Transmission Providers must ensure that the CBM methodology is consistent with the SERC Procedures for Transmission Capability Margins and the methodology at a minimum must include the following:
  - The LSEs' (including the native load of the host Transmission Provider) method to determine the generation reliability requirements within the Region
  - The frequency of calculation of generation reliability requirement and CBM (at least annually)
  - A requirement that generation unit outages considered in a Transmission Provider's CBM calculation be restricted to those units within the Transmission Provider's system
  - A requirement that CBM be preserved only on the host transmission system where the load is located
  - The inclusion / exclusion rationale for generation resources not directly connected to the host transmission system but serving native / network loads
  - The inclusion / exclusion rationale for generation connected to the host transmission system but not obligated to serve native / network load of the host transmission system
  - The exclusion rationale for any generation resource not specifically addressed above (such as resources owned by a Transmission Dependent Utility (TDU))
  - How CBM is incorporated into ATC calculations, including the relationship between the generation reserve requirement and CBM and the allocation of CBM to the appropriate transmission facilities
  - The inclusion / exclusion rationale for native / network load including interruptible loads
  - The inclusion / exclusion rationale for all long-term reserve sharing arrangements.
  - The components of CBM and the method of determining their values
  - The availability of CBM to the market as non-firm transmission service
  - Appropriate approvals from the SERC Region to deviate from the SERC approved Transmission Margins Procedures if required

CBM Review Methodology

SERC transmission providers will review annually their CBM methodology to ensure that the CBM calculations and values comply with SERC Transmission Capability Margins Procedure and NERC Planning Standards.

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CBM Methodology Deviation Approval Process

Any deviations from the SERC Transmission Capability Margins Procedure will be directed to the ATC Working Group (ATCWG). The ATCWG will then make recommendations for to SERC Engineering Committee and Operating Committee for their approval.

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Transmission Reliability Margin

Generally, the uncertainties associated with the operation of the interconnected electric system increase as the time horizon increases. These uncertainties can be attributed to weather conditions, forced and scheduled transmission outages, and generation unavailability. In the longer term, the health of the economy and the economics of generation will greatly influence the level and location of demand and electric resources. Because of these conditions, the uncertainties or "inaccuracy" associated with forecasts of TTC and ATC values also increase with time. The further into the future that TTC/ATC values are projected the greater the uncertainty. Therefore, the amount of TRM required is time dependent, generally with a larger amount necessary for longer time horizons than for near-term time periods.

Components of TRM

SERC Transmission Providers must consider the ATC margin components described in this section in their TRM calculations. Transmission Providers may set all or some of the component values to zero. However, documentation that supports the quantification of TRM, including zero TRM values, is necessary. SERC Transmission Providers are advised to use caution in developing estimates of each component and subsequently combining all components together. Such an approach may result in TRM values that are unnecessarily large. To avoid the duplication of TRM caused by "stacking" the components, SERC Transmission Providers may determine a surrogate TRM value that encompasses one or more of the TRM components described in this section. This determination of the surrogate TRM must be documented and supported by the Transmission Provider and reviewed and approved by the SERC ATC Working Group.

While the components that comprise TRM may be easily identified, the calculated values of these components may change depending upon experience and forecasts of system conditions. SERC Transmission Providers must address the TRM components for applicability to their systems. The methodology used to derive the TRM and TRM components must be documented and consistent with published planning criteria and must not account for uncertainties already accounted for elsewhere in the ATC determination. A TRM is considered consistent with published planning criteria if the same components that comprise the TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained.

The components of the TRM within SERC have the following unifying characteristics:

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- The beneficiary of this margin is the "larger community" with no single, identifiable group of users as the beneficiary. The benefits of the TRM extend over a large geographical area and over multiple Transmission Providers.

- They are the result of uncertainties that cannot reasonably be mitigated unilaterally by a single Transmission Provider or regional entity.

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Components that are to be considered in the determination of the TRM are listed below:

- **Variations in generation dispatch:** Location and output of generation assumed in planning and pre-operational horizons may be vastly different from actual operating conditions. A margin may be necessary to account for generation sensitivity effects on Transmission Capability.

- **Allowances for parallel path "loop flow" impacts:** Each network element, to some extent, is subject to parallel path flows. These parallel path flows are the result of transmission service transactions that are not explicitly scheduled on the transmission system of a particular Transmission Provider. Since these flows are not scheduled on his system, a Transmission Provider may not be aware of or able to explicitly account for the impact of other parties' transactions on his own system. Therefore, maintenance of a reasonable quantity of "uncommitted" transmission capacity will help to assure that the reliability of the entire Interconnection is maintained. Note that proper coordination of system data between Transmission Providers and Control Areas should minimize the magnitude of this component.

- **Allowances for simultaneous path interactions:** Transmission paths may interact and not be capable of operation at each path's full transfer capability. The secure operation under such situations can be described by a nomogram. TRM may be used to account for the difference between the firm capability of each interacting path and the maximum capability of each path. Nomograms may also be used to indicate the variability in capability of transmission paths as dictated by temperature, load level, available reactive support, and other factors.

- **Short-term Operator Response / System Response / Operating Reserves including Reserve-Sharing programs:** Following a contingency, system operators take immediate action, either individually or in concert with other operators, to maintain the reliability of the transmission system. Transmission capacity must remain available to allow for operator flexibility immediately following such a contingency. To maintain reliability, agreements between Control Areas exist to implement a quick and coordinated response following a transmission or generation contingency. These agreements include contracts among and between Reserve Sharing Groups (RSG). Operating reserve programs are designed to provide transmission operators with procedures needed to maintain reliability. Therefore, transmission resources needed to implement Operating Reserve Sharing Agreements for the period immediately following the contingency and before the reserves must be replaced is a TRM component.

  Operating reserves are additional capacity from either: a) generators that are on line, loaded to less than their maximum output, and available to serve customer demand

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immediately should a contingency occur, or from; b) generators that can be used to respond to a contingency within a short period of time, or from; c) load that can be curtailed within a short period of time, usually within ten minutes. The existence of interconnections allows the sharing of operating reserves between Control Areas, which reduces the amount of operating reserves each Control Area must carry on its own. The loss of a generating unit cascading into multiple system disturbances or load curtailments can be avoided by having adequate operating reserves. Operating reserve sharing programs have been implemented by a number of areas to provide reliability and economic benefits to the members of the group. As long as membership in these reserve-sharing groups remains open, they also provide benefit to the entire interconnected system. Operating reserves are provided for a limited time period. The consideration of operating reserves as a TRM component (unless explicitly modeled in TTC, as described later) recognizes that current procedures and technology limit the ability of the marketplace to replace a sudden loss of generation in real time. A quick replacement of an unexpected loss from a generation resource is necessary to maintain operating reliability performance levels. In fact, NERC's Interconnected Operations Services Implementation Task Force (IOSITF) has recommended that operating reserve sharing programs be designated as community Interconnected Operations Services that benefit the entire network. Therefore, although operating reserves are a generation quantity, operating reserve sharing agreements up to the time a Control Area must recover from a contingency by acquiring resources from other means benefit the entire Interconnection and must be considered a component of TRM.

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Components that are not to be considered in the determination of TRM:

- **Single transmission and generator contingencies:** These components shall be included in the determination of TTC, provided the contingencies are consistent with appropriate published NERC, Regional, sub-regional, power pool, and individual system reliability criteria.
- **All known generation and transmission outages:** Known outages are to be incorporated into ATC calculations for both firm and non-firm transmission service.

<u>TRM Application Methodology</u>

Within SERC, TRM is applied on a path-by-path basis. A path may consist of an entire interface or any other commercially viable transmission path posted on OASIS. TRM applied in this manner should be correlated to the uncertainty associated with TRM components through the use of historical transmission loading analysis. In this case, the SERC TRM is applied against a particular facility or set of facilities and is measured as a megawatt reduction in transfer capability.

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TRM should not be applied to paths limited by contract-based interconnection ratings or other contractual reasons (i.e., the path is "scheduling limited") since the capability of

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such a path is not subject to the uncertainties for which TRM is intended. However, a Transmission Provider may apply TRM to scheduling limited paths provided that the TRM determination method justifies the application. One such example is when a Transmission Provider incorporates a non-zero operating reserve sharing component into TRM, and then must subtract this amount from the contractual capability of the facility/ties in question.

SERC requirements for Transmission Providers to specify TRM

- Transmission Providers shall develop the calculation of the TRM component of ATC in accordance with applicable NERC standards and SERC procedures
- Each Transmission Provider shall make its TRM determination and methodology publicly available and will provide it to NERC and to SERC
- Transmission Providers must ensure that their TRM methodology is consistent with the SERC Procedures on Transmission Capability Margins and the methodology at a minimum must include the following:
  - TRM values will be reviewed at least 4 times a year prior to each season.
  - How TRM is incorporated into ATC Calculations
  - The components of TRM and the method of determining their values
  - The availability of TRM to the market as non-firm transmission service

TRM Review Methodology

SERC transmission providers will review annually their TRM methodology to ensure that TRM calculations are reviewed 4 times a year prior to each season and values comply with SERC Transmission Capability Margins Procedure and NERC Planning Standards. The results of the annual TRM methodology review will be made available to NERC, other regions, and Transmission Users.

TRM Methodology Deviation Approval Process

Any deviations from the SERC Transmission Capability Margins Procedure will be directed to the ATC Working Group (ATCWG). The ATCWG will then make recommendations for to SERC Engineering Committee and Operating Committee for their approval.

APPROVED

Brief Description Documentation and content of each Regional Capacity Benefit Margin methodology.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standards

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M1. Each Region, in conjunction with its members, shall develop and document a Regional CBM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S1)

Each Region's CBM methodology shall (S1):

a) Specify that the method used by each Regional member to determine its generation reliability requirements as the basis for CBM shall be consistent with its generation planning criteria.
b) Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
c) Require that generation unit outages considered in a transmission provider's CBM calculation be restricted to those units within the transmission provider's system.
d) Require that CBM be preserved only on the transmission provider's system where the load-serving entity's load is located (i.e., CBM is an import quantity only).
e) Describe the inclusion or exclusion rationale for generation resources of each LSE including those generation resources not directly connected to the transmission provider's system but serving LSE loads connected to the transmission provider's system.
f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system but not obligated to serve native/network load connected to the transmission provider's system.

g) **Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.**
h) **Specify the relationship of CBM to the generation reliability requirement and the allocation of the CBM values to the appropriate transmission facilities. 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.**
i) **Describe the inclusion or exclusion rationale for the loads of each LSE, including interruptible demands and buy-through contracts (type of service contract that offers the customer the option to be interrupted or to accept a higher rate for service under certain conditions).**
j) **Describe the inclusion or exclusion rationale for generation reserve sharing arrangements in the CBM values.**

Each Regional CBM methodology shall address each of the items listed above and shall explain its use, if any, in determining CBM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining CBM values.

The most recent version of the documentation of each Region's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to

Regions.

Items to be Measured

Development and documentation of each Region's Capability Benefit Margin methodology and the completeness of the content of each Regional CBM methodology.

Timeframe

Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance

Level 1

The Region's documented CBM methodology does not address one or two of the ten requirements for such documentation as listed above under Measurement M1.

Level 2

N/A.

Level 3
N/A.

Level 4
The Region's documented CBM methodology does not address three or more of the ten requirements for such documentation as listed above under Measurement M1, or the Region does not have a documented CBM methodology.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating

Brief Description	Measurement M2 was eliminated. Requirements are included in Measurement M3.

Brief Description Procedure for verifying Capacity Benefit Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M3. Each Region, in conjunction with its members, shall develop and implement a procedure to review the CBM calculations and values of member transmission providers to ensure that they comply with the Regional CBM methodology and are periodically updated (at least annually) and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S1)

This Regional procedure shall:

a) Indicate the frequency under which the verification review shall be implemented.
b) Require review of the process by which CBM values are updated, and their frequency of update, to ensure that the most current CBM values are available to transmission users.
c) Require review of the consistency of the transmission provider's CBM components with its published planning criteria. A CBM value is considered consistent with published planning criteria if the same components that comprise CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.
d) Require CBM values to be periodically updated (at least annually) and available to the Regions, NERC, and transmission users in the electricity markets.

The documentation of the Regional CBM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

Applicable to
Regions.

Items to be Measured
Regional procedure and its implementation for verifying member transmission provider CBM values.

Timeframe
Procedure on request (within 30 days).
Results of procedure implementation on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional CBM methodology, as documented per Measurement I.E.2 S1, M1, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a CBM methodology consistency review of all transmission providers within its Region, or has not performed any such review on an annual basis.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description Procedures for the use of Capacity Benefit Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M4. Each transmission provider shall document and make available its procedures on the use of CBM (scheduling of energy against a CBM preservation) to the Regions, NERC, and the transmission users in the electricity market.

These procedures shall (S1):

- **a) Require that CBM is to be used only 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 reestablish operating reserves.**
- **b) 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.**
- **c) Describe the conditions under which CBM may be available as non-firm transmission service. (S1)**

The transmission providers shall make their CBM use procedures available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

Applicable to

Transmission providers.

Items to be Measured

Documentation of CBM use procedures.

Timeframe

Available on a web site accessible by the Regions, NERC, and transmission users.

Levels of Non-Compliance

Level 1
The transmission provider's CBM use procedure is available and addresses only two of the three requirements for such documentation as listed above under Measurement M4.

Level 2
N/A.

Level 3
N/A.

Level 4
The transmission provider's CBM use procedure addresses one or none of the three requirements as listed above under Measurement M4, or is not available.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation of the use of Capacity Benefit Margin.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S1. Each Region shall develop a methodology for calculating Capacity Benefit Margin (CBM) that shall comply with the above NERC definition for CBM and applicable Regional criteria.

Each Regional CBM methodology and the resulting CBM values shall be available to transmission users in the electricity market.

Measurement

M5. Each transmission provider that uses CBM shall report to the Regions, NERC, and the transmission users 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. (S1)

Within 15 days after the use of CBM for emergency purposes, a transmission provider shall make available the 1) circumstances, 2) duration, and 3) amount of CBM used. This information shall be available on a web site accessible by the Regions, NERC, and the transmission users in the electricity market.

The use of CBM also shall be consistent with the transmission provider's CBM use procedures.

The scheduling of energy against a CBM preservation as non-firm transmission service need not be disclosed to comply with this Standard.

Applicable to

Transmission providers.

Items to be Measured

After the fact disclosure that energy was scheduled against a CBM preservation (for purposes other than non-firm transmission sales).

Timeframe

Within 15 days of the use of CBM (excluding non-firm sales).

Levels of Non-Compliance

Level 1
N/A.

Level 2
Information pertaining to the use of CBM during an energy emergency was provided, but was not made available on a web site accessible by the Regions, NERC, and transmission users in the electricity market, or meets only two of the three requirements as listed above under Measurement M5.

Level 3
N/A.

Level 4
After the use of CBM (excluding non-firm sales), information pertaining to the use of CBM was provided but meets one or none of the three requirements as listed above under Measurement M5, or no information was provided.

Compliance Monitoring Responsibility

Regions.

Reviewer Comments on Compliance Rating

Brief Description Documentation and content of each Regional Transmission Reliability Margin methodology.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurement

M6. Each Region, in conjunction with its members, shall develop and document a Regional TRM methodology. This Regional methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. (S2)

Each Region's TRM methodology shall (S2):

a) **Specify the update frequency of TRM calculations.**
b) **Specify how TRM values are incorporated into ATC calculations.**
c) **Specify the uncertainties accounted for in TRM and the methods used to determine their impacts on the TRM values.**

   The following components of uncertainty, if applied, shall be accounted for solely in TRM and not CBM: aggregate load forecast error (not included in determining generation reliability requirements), load distribution error, variations in facility loadings due to balancing of generation within a control area, forecast uncertainty in transmission system topology, allowances for parallel path (loop flow) impacts, allowances for simultaneous path interactions, variations in generation dispatch, and short-term operator response (operating reserve actions not exceeding a 59-minute window).

   Any additional components of uncertainty shall benefit the interconnected transmission systems, as a whole, before they shall be permitted to be included in TRM calculations.

d) **Describe the conditions, if any, under which TRM may be available to the market as non-firm transmission service.**

e) **Describe the formal process for the Region to grant any variances to individual transmission providers from the Regional TRM methodology.**

Each Regional TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are Regional specific or that are considered in each respective Regional methodology shall also be explained along with their use in determining TRM values.

The most recent version of the documentation of each Region's TRM methodology shall be available on a web site accessible by NERC, the Regions, and the transmission users in the electricity market.

Applicable to
Regions.

Items to be Measured
Development and documentation of each Region's Transmission Reliability Margin methodology and the completeness of the content of each Regional TRM methodology.

Timeframe
Available on a web site accessible by NERC, the Regions, and transmission users.

Levels of Non-Compliance

Level 1
The Region's document TRM methodology does not address one of the five requirements for each documentation as listed above under Measurement M6.

Level 2
N/A.

Level 3
N/A.

Level 4
The Region's documented TRM methodology does not address two or more of the five requirements for such documentation as listed above under Measurement M6, or the Region does not have a documented TRM methodology.

Compliance Monitoring Responsibility
NERC.

Reviewer Comments on Compliance Rating

Brief Description (Measurement M7 was eliminated. Requirements included in Measurement M8.)

Brief Description Procedure for verifying Transmission Reliability Margin values.

Section
I. System Adequacy and Security
E. Transfer Capability
2. Transfer Capability Margins

Standard

S2. Each Region shall develop a methodology for calculating Transmission Reliability Margin (TRM) that shall comply with the above NERC definition for TRM and applicable Regional criteria.

Each Regional TRM methodology and the resulting TRM values shall be available to transmission users in the electricity market.

Measurement

M8. Each Region, in conjunction with its members, shall develop and implement a procedure to review the TRM calculations and values of member transmission providers to ensure that they comply with the Regional TRM methodology and are periodically updated and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC on request (within 30 days). (S2)

This Regional procedure shall:

a) Indicate the frequency under which the verification review shall be implemented.

b) Require review of the process by which TRM values are updated, and their frequency of update, to ensure that the most current TRM values are available to transmission users.

c) Require review of the consistency of the transmission provider's TRM components with its published planning criteria. A TRM value is considered consistent with published planning criteria if the same components that comprise TRM are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumption explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.

d) **Require TRM values to be periodically updated (at least prior to each season ¾ winter, spring, summer, and fall), as necessary, and made available to the Regions, NERC, and transmission users in the electricity market.**

The documentation of the Regional TRM procedure shall be available to NERC on request (within 30 days). Documentation of the results of the most current implementation of the procedure shall be available to NERC on request (within 30 days).

Applicable to

Regions.

Items to be Measured

Regional procedure and its implementation for verifying member transmission provider TRM values.

Timeframe

Procedure on request (within 30 days).
Results of procedure implementation on request (within 30 days).

Levels of Non-Compliance

Level 1
N/A.

Level 2
The Region did not perform a review of all transmission providers within its Region for consistency with the Regional TRM methodology, as documented per Measurement I.E.2 S2, M8, on an annual basis.

Level 3
N/A.

Level 4
The Region does not have a procedure for performing a TRM methodology consistency review of all transmission providers in its Region, or has not performed any such reviews on an annual basis.

Compliance Monitoring Responsibility

NERC.

Reviewer Comments on Compliance Rating