Long-Term AFC/ATC TASK FORCE

FINAL REPORT

March 15, 2005

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Executive Summary

The Long-Term AFC/ATC Task Force[1] (LTATF) was created by the NERC Market Committee to address the long-term recommendations outlined by the Alliant West TLR Task Force (AWTTF).[2] The purpose of the LTATF was to develop a report and specific recommendations for the calculation and coordination of AFC/ATC[3] to increase market liquidity and enhance reliability. The task force also used the report and recommendations to develop a proposed business practice standard and proposed revisions to related reliability standards, which are included as attachments to this report.

The major areas the task force considered were:

- Communication and Coordination of AFC/ATC (respecting 3rd party constraints)
- Calculation Process for AFC/ATC
- Consistency between planning criteria and the attributes of the AFC/ATC calculations (over both planning and operating horizons)

The task force also evaluated the results of the short-term recommendations of the AWTTF in the Alliant West area for summer 2004 and used this evaluation to recommend that the Alliant West short-term recommendations be extended to March 31, 2005, from the original expiration date of September 30, 2004. See Appendix D.

The NERC Market Committee directed the task force's efforts, and the task force coordinated its work with representatives from NAESB. The task force met nearly monthly from June 2004 through March 2005 to expedite the completion of its work.

Background

Since FERC's Order 888 first mandated the sale of transmission service by FERC-jurisdictional entities to wholesale electric customers, thus necessitating the explicit calculation of ATC, the industry has evolved significantly.

Although some progress was made publicizing and defining an algorithm for ATC calculations in Order 888 and the NERC Board of Trustees approved a document entitled "*Available Transfer Capability Definitions and Determination,*"[4] an industry-wide methodology still does not exist today.

Furthermore, as the industry has discovered, during the work of the AWTTF and now with the LTATF, the lack of standardization and more significantly, limited coordination can negatively impact both the market, through the need for a large number of Transmission Loading Relief (TLR) actions (or curtailments in WECC) and, on occasion, reliability when even the use of TLRs provides insufficient relief on some critical interfaces.

[1] See Appendix G for the LTATF roster.

[2] The Alliant West TLR Task Force (AWTTF) was created during the November 2003 Standing Committee meetings to develop specific recommendations for market and operating practices to address problems associated with TLR curtailments in the Alliant West region expected in summer 2004. Its report is available on NERC website at: ftp://www.nerc.com/pub/sys/all_updl/mc/ltatf/AWTTF_FERC_Filing_040204.pdf

[3] Available Flowgate Capability / Available Transfer Capability

[4] ftp://ftp.nerc.com/pub/sys/all_updl/docs/pubs/atcfinal.pdf

There are also other elements of the industry's evolution that have changed the nature of the calculations and the interactions between neighbouring transmission providers. These include:

- The use of Available Flowgate Capability (AFC) calculations in conjunction with ATC.
- The development of centralized markets resulting in market to non-market interfaces.
- Agreements between neighbouring ISOs/RTOs and transmission service providers that have resulted in the increased coordination of operation and transmission service request processing.

While these changes have modified the relationship between Transmission Service Providers (TSPs), they have not reduced the relevance of ATC or AFC to both market participants and reliability coordinators. There is still a need for further industry-wide improvement because of continuing outages, curtailments, TLRs, and other reliability and commercial concerns.

Other appendices contain two proposed NERC standard authorization requests, a proposed NAESB business practice standard, and additional information related to the topics covered by the task force and used as a foundation for the development of the proposed standards.

LTATF AFC / ATC Discussions and Analyses

During the course of the LTATF investigation, the task force developed three groups of issues:

1. Communication and Coordination of AFC/ATC — respecting 3rd party constraints
2. Calculation Process for AFC/ATC
3. Consistency between planning criteria and the attributes of the AFC/ATC calculations (over both planning and operating horizons).

Those three issues are further outlined below:

1. Communication & Coordination of AFC/ATC — respecting 3rd party constraints

   The objective of ATC/AFC coordination is to ensure that neighboring entities exchange relevant information to facilitate:

   a. a reasonable representation of external entities in the model for calculating AFC/ATC;
   b. the ability for each Calculator to honor flowgates in third party systems; and
   c. the ability for each Calculator to translate data from neighboring entities and make meaningful use of the data in their respective calculations.

   Further details are contained in *Appendix A*.

2. Calculation Process for AFC/ATC

   The task force agreed that TSPs need to provide better documentation and greater transparency for their AFC/ATC calculation processes.

   a. The proposed Standard Authorization Request (SAR) contains recommendations to achieve more consistency among AFC/ATC calculations.
   b. The task force conducted a review of ATC methodologies and found that numerous ATC calculators in the Midwest have been replaced with MISO and PJM.
   c. Additionally, the task force found industry-wide approximately 50–60 ATC calculators (TSPs posting to their OASIS website), with many (30–40) in the West.

d. The task force also felt that consistency is important in the calculation of Capacity Benefit Margin (CBM) and Transmission Reserve Margin (TRM), and is reflected in the attached SAR recommending a revision to the applicable standards.

The task force found several different ways ATC, TTC[5], TRM, and CBM are calculated and used, and are dependent on the type of market system utilized and electrical topology. Following are some examples:

- Some first calculate TTC and then derive ATC
- Some first calculate ATC and then derive TTC
- Some first calculate AFC and then derive ATC
- Some only calculate TTC
- Some use CBM and some don't use CBM
- The scope of CBM varies by footprint
- Nearly all use TRM

3. Consistency between planning criteria and the attributes of the AFC/ATC calculations (over both planning and operating horizons)

   a. The task force emphasized the requirement that assumptions used in the calculation of AFC/ATC and CBM/TRM should be consistent with those used in the respective planning and operating horizons (see Appendix E). The assumptions should be documented and transparent to stakeholders.

[5] Total Transfer Capability

LTATF Recommendations and Other Issues

Data Input and Utilization — Calculation Process for AFC/ATC

I. The task force recommends that NERC should establish minimum data entry and utilization requirements with standardized data definitions and definitions for the frequency and timing for exchanging data.

II. The task force recommends that TSPs should be required to publish their methodology for the calculation of ATC or AFC, detailing how they deal with all of the items identified in Appendix A, or state why they are not relevant to their calculation.

III. Standardization of the treatment of these items remains an additional objective. This information should be provided according to a template to be included as part of the compliance with the proposed NAESB Business Practice Standard and/or proposed revisions to Reliability Standards that are attached to this report.

TRM/CBM — Calculation process for AFC/ATC

The LTATF passed the following strawman motion by a vote of 15 to 2:

Because the LTATF debated at length the merits of CBM calculation and utilization, the LTATF asks the SAR Drafting Team (SAR DT) to consider whether the calculation and/or withholding of CBM as an explicit quantity is necessary for reliability and should be part of a reliability standard.

If the industry still considers CBM to be necessary, the SAR DT is asked to consider the following recommendations:

IV. The task force recommends that NERC revise its standard on the calculation of CBM/TRM and that NAESB establish a standard on the use of CBM that would replace the NERC CBM standard associated with the use thereof.

V. The task force recommends that NERC and complementary NAESB standards should require transparency*, but not be a prescriptive methodology,* for the calculation and use of CBM/TRM.

VI. The task force recommends that NERC standards should provide guidelines for parameters that should be included in the TRM/CBM calculation, and reconcile methodologies where a RTO might cover several regions with differing methodologies.

See *Appendices C and F*.

Monitoring/Coordination — Communication and Coordination of AFC/ATC

VII. The task force recommends the revision of the existing NERC standards to require the recognition and respect of impacts on external flowgates/paths in AFC/ATC calculations, and the establishment of NERC standards on AFC/ATC coordination.

Frequency of Calculations — Calculation Process for AFC/ATC

VIII. The task force recommends the revision of NERC standards to increase the frequency of AFC/ATC calculations (e.g., see Appendix D on Alliant West recommendations).

Source and Sink Points - Calculation Process for AFC/ATC

The task force suggests that the sources and sinks (injections and withdrawals) used in the calculation of AFC/ATC and the evaluation of transmission service requests should replicate the anticipated use of service when utilized. It is important that TSPs have business practices outlining when they will allow confirmed transmission reservations to be used in manner that is not equivalent to how the request for the service was evaluated.

IX. Therefore, the task force recommends that the NERC SAR DT establish or revise an existing standard to ensure that the calculation of AFC/ATC and the evaluation of the transmission service request reflect the anticipated usage of that service when that service is utilized.

X. The task force also recommends that NAESB develop a business practice standard that relates to the processing and evaluation of request(s) to schedule against approved transmission service reservation(s). See Appendix B for additional details.

XI. The task force also recommends that the SAR DT should review or create FERC / NERC definitions and utilizations of source and sink when revising the standard.

XII. The task force also recommends that that NAESB develop a Business Practice Standard related to the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM. (see attached proposal for a NAESB business practice standard)

Curtailment Threshold Consistency — Calculation Process for AFC/ATC

The task force discussed distribution factor cutoff consistency between calculation of AFC/ATC and activation of TLR. The task force acknowledged existing inconsistencies among TSP practices. The task force did not reach a conclusion regarding an appropriate curtailment threshold level, and suggests that a larger stakeholder body would be necessary to reach a consensus.

Appendix A

ATC/AFC Coordination and Calculation

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LTATF Appendix on AFC/ATC Coordination and Calculation

1.0 Introduction:

The purpose of this paper is to provide an overview of the process of calculating and coordinating transfer capability (AFC/ATC). The paper outlines existing coordination processes in the Eastern Interconnection (EI) and the WECC. The paper also defines a proposed method of exchanging ATC/AFC data between entities. The last section is a summary of minimum requirements for flowgate exchange and modeling techniques to facilitate proper calculation and coordination of transfer capability (AFC/ATC).

2.0 Coordination:

The objective of ATC/AFC coordination is to ensure that neighboring entities exchange relevant information to facilitate:

a) a reasonable representation of external entities in the model for calculating AFC/ATC
b) the ability for each Calculator to honor flowgates in third party systems
c) the ability for each Calculator to translate data from neighboring entities and make meaningful use of the data in their respective calculations

The NERC SDX is a platform for data exchange between the various NERC regions. Several entities have developed alternate platforms to exchange data as a supplement to data exchange via SDX. Each NERC region has its own document outlining the coordination and calculation of transfer capability by its members.

Following is a summary of the coordination processes in place in major regions in NERC:

Eastern Interconnection:

In the EI, several entities have signed operating agreements to facilitate the coordination process. The following agreements are currently in effect or have been filed with the FERC:

a) MISO – PJM[1]
b) MISO – MAPP[2]
c) SPP - MISO[3]

SERC and FRCC members consist predominantly of ATC calculators. Coordination standards for SERC members are outlined in the SERC supplement[4] to the NERC planning standards.

Western Interconnection:

WECC members coordinate transfer capability through seasonal studies[5].

[1] http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf
[2] http://www.midwestiso.org/initiatives/joa_seams/mapp_seams/docs/Final_SOA_modified_01142005.pdf
[3] http://www.midwestiso.org/initiatives/documents/12-02-04%20FERC_Filing_SPP-MISO-JOA.pdf
[4] http://www.serc1.org/Pages/DocumentDisplay.aspx?FN=SERC%20Supplements/Planning/IE1%20SERC%20Supplement%203-8-02.PDF
[5] http://www.wecc.biz/documents/library/procedures/ATC-apprdec01.pdf

2.1 Exchange of data between and AFC and ATC calculator:

This section outlines an option to enable entities to exchange useful information on flowgates for use in their calculations.

2.1.1 AFC calculator reading data from ATC calculator:

- ATC calculator determines CE/LE (contingent element/limiting element/monitoring element) pairs that are limiting to transfers
- List is sorted to identify CE/LE pairs that are in the list of monitored flowgates for the AFC calculator
- For these CE/LE pairs, an equivalent AFC value is transmitted to the AFC calculator.

2.1.2 ATC calculator reading data from AFC calculator:

- AFC calculator supplies list of flowgate AFC values to the ATC calculator
- ATC calculator translates the AFC value into the model by adjusting the rating of the LE such that under contingency or non-contingency (as appropriate for the specified flowgate), the adjusted rating - flow (LE) equals the AFC value supplied by the AFC calculator

2.2 Flowgate data exchange and modeling requirements:

This section outlines the list of flowgates that should be considered for the coordination process. The section also defines modeling requirements for entities performing the transfer capability calculations.

2.2.1 Each TSP will consider in its TTC and ATC/AFC determination process all third party flowgates:

(i) that are significantly impacted by its transactions, or
(ii) as mutually agreed between the parties, subject to the following:

- A TSP's transactions are deemed to significantly impact another TSP's flowgates if they have a response factor equal to or greater than the response factor cutoff (threshold) used by the owning TSP.
- The parties, in their AFC determination and transmission service processing efforts, shall use the response factor cut-off that the owning/operating TSP uses for its flowgates.
- The TSPs shall coordinate their counterflow assumptions on affected flowgates.
- At a minimum, coordination should occur on flowgates in transmission systems that comprise the first tier with respect to the TSP.
- To the extent a TSP is coordinating AFC on a requested flowgate, the TSP needs to ensure that modeling around the flowgate is sufficient to produce reasonable response factors. As an alternative, the TSP can use response factors provided by the requesting TSP.

2.2.2 All entities should meet the following minimum modeling requirements:

- Transmission providers should use reasonably accurate response factors
- Model should include the TSP's control area as well as control areas within the footprint of the adjacent TSP's tariff
- Equivalent model representations for beyond first-tier transmission providers / control areas are acceptable as long as they enable calculation of accurate response factors
- Use of an MMWG base case, modified by appropriate NERC SDX system conditions, would be considered a reasonable alternative
- If an area is too small or its model too limiting, it should delegate its calculations to an entity that has the capability to perform the calculations with appropriate modeling capabilities

2.2.3 In the absence of a mutual agreement, or for a waiver from this requirement, NERC or its designate shall define for the TSPs those external system modeling requirements to be used for TTC/ATC/AFC calculations.

Glossary

TTC	*Total Transfer Capability*
ATC	*Available Transfer Capability*
AFC	*Available Flowgate Capability*
SDX	*System Data Exchange: NERC tool to facilitate electronic data exchange*
MMWG	*Multi-regional model working group (NERC working group responsible for power flow model development)*
TSP	*Transmission Service Provider*
CE/LE	*Contingent Element/Limiting Element; typically used to identify facilities that define a flowgate*
OTDF	*Outage Transfer Distribution Factor*
PTDF	*Power Transfer Distribution Factor*
LODF	*Line Outage Distribution Factor*

1. ATC/AFC Equations

Basic transmission service is sold to customers in the form of " Transfer Capability " (TC). Available Transfer Capability (ATC) is the amount of transfer capability still available for sale after all existing uses are accounted for. Transfer Capability (TC) is measured along a path from source to sink. Transfer Capability is limited by the capacity of either equipment (such as transformer, circuits) or interfaces (collection of circuits). An example of an interface limit would be a voltage or stability limit that can be measured as a maximum flow on an interface or a thermal contract path limit.

A "flowgate" is the name given to the transmission element(s) and associated contingency if any, that may limit ATC. Available Flowgate Capability (AFC) is a measure of the capability remaining on a flowgate for future uses, after considering the impact of prior sales. AFC is measured as a "flow" limit on a flowgate, while ATC is measured as a "transaction" limit from a source to sink. There are typically several flowgates between source and sink that can limit the transaction. Transactions distribute amongst these flowgates based on the transmission configuration. The percent distribution of a transaction on a flowgate is determined via power flow analysis and is called a distribution factor (DF) (this term is interchangeable with "response factor") whereby:

$$AFC(f) = DF(t,f) * ATC(t,f)$$

t = defined path from source to sink
f = flowgate "f"
ATC(t,f) = The maximum transaction for path t available as limited by flowgate "f"
AFC(f) = AFC for flowgate "f"
DF(t,f) = percentage of transaction on path that flows on flowgate "f"

Typically, AFCs are determined for all flowgates and ATC is then determined from AFC. For this reason, the equation is more frequently used in the format:

$$ATC(t,f) = AFC(f)/DF(t,f)$$

The overall "ATC" is the "minimum" ATC calculated from the above equation for all flowgates. Posted ATCs must therefore have an associated "most limiting" flowgate. Each flowgate has an associated AFC for the time frame being studied, which can be used to calculate an ATC for any potential path.

Other Relationships:

Total Flowgate Capacity (TFC) is generally equal to the *rating* of the flowgate. A typical flowgate might consist of a limiting circuit, or "monitored" circuit, along with the outage that limits the monitored circuit. An "interface" flowgate's AFC is typically set to a flow value above which a stability or voltage limit will be exceeded.

Basic Equations:

AFC = TFC – Base Network Flows(Native & Network load model) – Margins (such as CBM/TRM) – Effect on the flowgates of existing transmission reservations

Margins:

Capacity Benefit Margin (CBM)[1] or Transmission Reserve Margin (TRM)[1] are margins used in ATC or AFC calculations to account for uncertainties or contingencies that are not explicitly modeled in the calculations due to time constraints. The criteria used to determine these values must be consistent with the TO's planning and operating criteria. A more detailed description of these margins can be found in the NERC white paper titled "Transmission Capability Margins and Their Use In ATC Determination" dated June 17, 1999.

2. Translation of ATC/AFC for Data Exchange Between Entities

Sharing of ATC/AFC quantities between entities, which sell transmission service, requires translating the data from ATC to AFC (& vice versa) if one of the entities uses ATC and the other uses AFC as a basis. The basic AFC/ATC equations discussed earlier can be used to "translate" shared data:

$$ATC(t,f) = AFC(f)/DF(t,f)$$

Where:

(t) is a defined source to sink transaction

(f) is any flowgate

DF is the distribution factor on the flowgate of the defined source to sink transaction.

Defined source to sink transactions are those qualifying for transmission service. For example, if two RTOs are coordinating data and the transaction is from a source in one to a sink in the other the direct path is usually not available. The transaction would be from the source in RTO number 1 to a border interface with RTO number 2. The transaction in RTO number 2 would be from the border interface to the sink in RTO number 2. Each RTO would be responsible for its portion of the transactions. Even if the transmission purchaser is oblivious to the intervening interface, the RTOs share their own piece of the calculation. This situation has the inherent problem that the true source to true sink is ignored when a "border" is introduced. It is a similar problem to "hubbed" transactions where transactions are ultimately split from the source to the "hub" and then from the "hub" to the sink.

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1 "Transmission Capability Margins and Their Use in ATC Determination - White Paper" NERC ATCWG document dated 9/28/99. Available from the following URL: http://www.nerc.com/~filez/atcwg.html

Appendix B

Source / Sink

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Appendix B

LTATF Appendix on Source/Sink

1. Introduction

The purpose of this appendix is to provide guidance on "source" and "sink" point assumptions used in AFC/ATC calculations and in the evaluation of Transmission Service Requests.

2. Source/Sink Points in Transmission Analysis

The assumptions of source and sink points are fundamental in the determination of transfer capability. The North American Electric Reliability Council *(in "Glossary of Terms" – August 1996)* defines Transfer Capability as follows: It is "the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another area by way of all transmission lines between those areas under specified system conditions."

The Transfer Capability between two areas is typically assessed or determined by modeling a generation excess in the "from" area at a specific source point(s) and a generation deficiency in the "to" area at a specific sink point(s). The increased source level at which the loading on a transmission element is at its normal rating (with no contingencies) or its emergency rating (with an outage of a generation unit or a transmission element) is be defined as the incremental Transfer Capability.

Selection of the specific source and sink points will impact the calculated "power transfer distribution factors" and various transmission facility loadings to determine the AFC/ATC values and to determine the anticipated impact of a Transmission Service Request on specific Flowgates. Therefore, the posted AFC/ATC, as well as the evaluation of a transmission service request, is greatly influenced by the selection of these points. Transmission service sold based on a set of source/sink points that do not correspond to the generation that moves for the schedule results in inaccurate ATC values.

3. Source and Sink Point Concepts

Source and sink points, for the purpose of this appendix, do not necessarily correspond to the source or sink fields on a transmission reservation, but are constructs that mimic the expected actual change in generation dispatch that would be used to affect that power transfer in real-time. When determining a Transfer Capability (or determining ATC/AFC or evaluating a transmission service request) by modeling a power transfer, there are several ways to model the various source and sink points. Source/sink points have the following general characteristics:

a. Source points could be generalized into the following four categories:

    i. Increase generation level of an individual unit or units at a station
    ii. Increase generation level of a group of units that represent a system dispatch
    iii. Load Reduction (if there is no available generation in the source system)
    iv. A combination of increasing generation and reducing load

b. Sink points could be generalized into the following four categories:

   i. Decrease generation level of an individual unit or units at a station
   ii. Decrease generation level of a group of units that represent a system dispatch
   iii. Load increase when the sink area is not at projected peak
   iv. A combination of decreasing generation and increasing load

c. Sources and Sinks Modeled at a Single Bus

   Load reduction at a single bus would not usually be considered a valid source in the ATC/AFC calculations. A load increase on a single bus should be considered a valid sink only when a designated load is modeled entirely on that one bus.

d. Source and Sink Points as a Group of Load Points

   Similar to a single bus, a group of load buses is not typically considered a valid source unless there is no available generation in the source system. Load can be considered a valid sink point if the sink system is not at the anticipated peak load or if no sink system generation is available to scale down.

e. Source or Sink Point from a Single Unit or Plant

   Although utilizing a single unit or plant as a source or sink is acceptable, the provider must be careful to ensure the methodology is technically correct if/when reservations exceed the capability of the unit or plant, how redirects are handled and how service decrements flowgates.

f. Source and Sink Points as a Group of Units

   If a group of units or a control area is utilized as source and/or sink points, the following needs to be addressed in the transmission provider's ATC/AFC methodology.

   The assumptions used in the creation of the 'subsystem' should mimic the dispatch of these units in real-time conditions. For example, issues that must be considered include economic dispatch order, jointly owned units, intermittent resources (e.g. wind and run of the river hydro) and how the ATC calculation will address the potential of generation modeled in excess of capacity (when the fleet is a source) and/or generating 'negative' generation (when the fleet is a sink).

   When determining participation points, consideration needs to be given to whether the source or sink subsystem is dispatched by a single entity, such as a centralized market dispatch, a vertically integrated utility, or if all generators in a locality, including municipal generation and IPPs, are part of the single subsystem. The transmission provider must rationalize the consistency of these assumptions with real time operations.

g. Source and sink points used to represent the source or sink area being studied need to be physically located in those areas. To the extent possible, the ultimate source and ultimate sink should be utilized, not just source and sink points at the border or in the first tier of the transmission provider.

h. The source and sink on the energy tag should match the sources and sinks used to evaluate the transmission service request. (This is a scheduling issue)

4. Conclusion

Source and sink assumptions are a critical ingredient in the determination of ATC values. To the extent practical these assumptions need to reflect the actual generation dispatch used to implement a power transfer between two entities. If the source/sink assumptions do not reasonably mimic real time operations, the resultant ATC will reflect this inconsistency through values that result in overselling of transmission or the underutilization of the transmission capacity. In the case of over-estimation of ATC, the transmission system could be oversold, resulting in avoidable operating challenges in real time, including TLRs and curtailments, as well as generation costs associated with a less than efficient generation dispatch. In the case of underselling the transmission system, due to under-estimation of ATC values, the results are missed opportunity costs due to the underutilization of the transmission system.

It is important that the transmission provider document how sources and sinks are established and utilized in their ATC/AFC process to ensure consistency and to ensure that the methodology is validated.

Appendix C

Review of Current NERC Standards on CBM and TRM

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Appendix C

LTATF Appendix on the Review of Current NERC Standards on Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM)

The purpose of reviewing the current NERC standard on CBM and TRM was to determine if there were any deficiencies that could be addressed in a new proposed standard for Available Transfer Capability (ATC) and its associated margins CBM and TRM. In general, it was determined that the standard could be improved in the four following categories:

1. Independent Review
2. Consistency
3. Additional Specificity Where Feasible
4. Seams Issues

These four categories could possibly also apply to the current NERC standard on ATC calculations. Additional details of the review are as follows:

<u>Independent Review</u>

The current CBM and TRM standard calls for Regional Reliability Organization (RRO) methodologies to be established. The Regional methodologies are reviewed by NERC to determine if they address the subject matter listed in the standard. There is no judgment made regarding if the methodology is reasonable or correct. The Regions then review the ATC calculators in their areas to determine if they are following the methodology.

It is recommended that a new standard require a written methodology and be very specific regarding what subject matter is covered in the written methodology. The standard drafting team should also consider a requirement that all documents be in a specified format or at least follow the same outline. The standard would only require that the methodology address all specified subject matter and be publicly available. Any issues regarding the methodology or its resulting values would not be addressed by the standard, but would be addressed via an open process that the standard would require the owner of the methodology to have. Any dispute resolution would be handled by NERC or its designate.

To keep the number of methodologies to be reviewed to a reasonable number the following entities would be required to have written methodologies:

- RTOs and ISOs that calculate TRM and/or CBM would be required to have written methodologies that incorporate input from those RROs that are within or partially within the RTO/ISO.
    - **Would an RTO methodology be subject to FERC or NERC?**
        - **NERC or NAESB, as appropriate**
- Where the TO is not part of an RTO, individual transmission owners (TO) that calculate their own TRM and/or CBM or provide input data to a centralized AFC/ATC process where the calculation is done on their behalf must abide by a RRO methodology.

To provide consistency in the reviews, a single entity such as NERC or its designate must review all the methodologies to determine if they are compliant with the standard.

In addition, NERC or its designate will review the ISOs and RTOs who calculate TRM and/or CBM to determine if they are following their methodologies. Any TOs who are determining their own TRM and/or CBM values must be reviewed by the entity whose methodology they are using, to ensure consistency with the methodology. The reviews of the individual TO calculations must be summarized and the reports reviewed by NERC or its designate.

Consistency and Additional Specificity Where Feasible

The existing CBM and TRM standard could be more specific in the following areas:

1. Frequency of calculation must be at least annually or upon any change pursuant to FERC Order 889.
2. Provide guidelines for the following items in the CBM standard
    a. Item 1e. Generator resources
        1. All generation directly connected to the TSP's system being used to serve load directly connected to that system would be considered in the CBM requirement determination.
        2. All generation not directly connected to the TSP's system being used to serve load directly connected to that system will be considered as "perfectly available" generation in the CBM requirement determination.

    b. Item 1f. Definition of generators connected to the system
        1. The following units are included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:
        - All generation directly connected to the TSP's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.
        - All generation not directly connected to the TSP's system being used to serve load directly connected to that system will be considered as perfectly available generation in the CBM requirement determination.
        - Generation directly connected to the TSP's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows:
            - Generation directly connected to the TSP's system but committed to serve load on another 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 are committed to serve load on another system and therefore not available to serve load on the system for which the CBM requirement is being determined.

            - Generation directly connected to the TSP's system but not committed to serve load on any system will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:

a. The TSP will use the best information available to them (i.e. confirmed or requested transmission service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.

b. If no information on these units is available, the TSP will use the following default: Fifty percent of the generation directly connected to the TSP's system but not committed to serve load on any system will be included in the CBM requirement determination. By including all this generation, the CBM requirement may be reduced too much, and by excluding it the CBM requirement may be increased too much. Since this generation is uncommitted, there is a 50/50 probability that the energy will or will not be purchased to serve load connected to the TSP's system. Using the 50% value is a midpoint between the two extremes (using all the uncommitted generation or using none of the uncommitted generation).

3. Consistency with Planning Criteria
    a. The existing CBM standard already requires this consistency
    b. The TRM standard must require that the components that comprise the TRM are planned for by the TO or other planning entity.
    c. The entity responsible for the CBM/TRM Methodology will be required to review the TO or other planning entity to ensure there is consistency with their planning criteria. The planning criteria consistency reviews will then be reviewed by NERC or its designate.
4. Dates that seasonal CBM and TRM values apply must be specified in the methodology

<u>Seams Issues</u>
The existing CBM and TRM standard could be more specific in the following area:

1. Coordination of CBM and TRM values on flowgates especially tie-lines. (This issue can be covered in the AFC/ATC standard under coordination)

Appendix D

Evaluation of the AWTTF Short-term Recommendations

NERC LTATF

Appendix D

LTATF Appendix on the Review of the Evaluation of the AWTTF Short-term Recommendations

Evaluation of the AWTTF Short-term Recommendations

I. Emergency Redispatch

For the identified Alliant West flowgates, the reliability coordinators shall identify key redispatch combinations and develop operating procedures that would relieve the defined Alliant West flowgate constraints in the event emergency redispatch was quickly needed to prevent an imminent threat of collapse, cascading or significant loss of load.

STATUS: MISO has identified three situations under which emergency dispatch will be implemented:

1. *If the actual real-time flow on the monitored element exceeds the emergency rating, the MISO RC shall order immediate emergency redispatch using any combination of the increment and decrement units.*
2. *If the calculated post-contingency loading on the monitored element is greater than 100% but less than 125% of the monitored elements emergency rating, the MISO RC will institute TLR to return within 100% of the emergency rating. If there is insufficient relief available from TLR or relief is not being accomplished within 60 minutes of the initial surpassing of the emergency limit, the MISO RC will order emergency redispatch. The emergency redispatch must be ordered to arrest the problem within 60 minutes of the initial surpassing of the post-contingent emergency rating*
3. *If calculated post contingency loading on the monitored element is greater than 125% of the monitored element's emergency rating, the MISO RC will implement emergency dispatch immediately. The emergency redispatch must be ordered to arrest the problem in 30 minutes of the initial surpassing of the post contingent emergency rating.*

II. Planning

Alliant and MISO should ensure that planning studies are underway to identify what transmission facilities would need to be upgraded or added to accommodate known firm transactions and reliability needs in the Alliant West area.

STATUS: MISO Expansion Planning Group study will be factoring in Alliant West flowgates for the creation of a 2009 base case for the MISO Transmission Expansion Plan. Alliant will be conducting an eastern Iowa study with the Iowa Transmission Working Group.

Alliant has initiated their Transmission Planning Study.

III. Source and Sink Points

a. Within 10 days following a TLR level 5 or higher MISO shall work with other transmission providers to investigate all transaction pairs within the IDC having an impact of 3% or greater on the designated Alliant West flowgate that exist each hour of the TLR 5. The NERC TLR report will, for each schedule flowing during TLR 5, give evidence that generators designated for the schedule through the approval process that were specified as a POR were actually on line delivering sufficient energy for the schedule(s), at the time of the TLR5.

b. If the unit that was designated as part of the schedule was not on line, the Midwest ISO shall request and report the response of the entity responsible (PSE, TP, etc) for the schedules as to what the actual source of the schedule was at the time of the TLR.

STATUS: MAPP is committed to gathering data. MISO has established procedures for those cases where transmission is granted on a unit specific basis.

IV. AFC Coordination

a. Updated Alliant West flowgate AFC values will be made available (was scheduled for implementation by March 10th) by MISO as follows:

   i. For hourly, once per hour

   ii. For daily, once per hour (calculated four times per day)

   iii. For monthly, once per hour (calculated twice a month)

b. For the evaluation of transmission service requests, the identified transmission providers should utilize the updated AFC from MISO at the frequency noted below:

   i. For hourly, once per hour.

   ii. For daily, once per day

   iii. Monthly, once a week

   For those transmission providers that cannot meet the recommended frequency, provide an indication to NERC of why and what is possible by June 1, 2004, and when they would anticipate being able to fully meet the recommended frequency.

c. Transmission providers shall not approve additional hourly, non-firm transmission during the expected remaining duration of a TLR Level 3 or higher curtailment, or until the TLR Level 3 or higher has ended, for those reservations that negatively impact (3% or greater) the designated Alliant West flowgates. This requires that transmission providers recognize the hourly AFC/ATC values provided by MISO during TLR level 3 or higher.

STATUS: PJM, SPP, Grid America, MISO (including Ameren and IP), MAPP (for non-MISO members) and AECI indicated that they are meeting the frequency called for above.

V. Monitoring

The identified transmission providers listed on page three[1] must monitor the identified Alliant West flowgates using a 3% OTDF threshold, unless MISO agrees that it is not required. AFCs will be provided for these flowgates by MISO and those AFC values must be implemented in any AFC/ATC calculation process and transmission service request evaluation process of the transmission providers specified below.

For those transmission providers that cannot meet the monitoring request, provide an indication of why and what is possible by June 1, 2004, and when they would anticipate being able to fully meet the recommended monitoring.

STATUS: PJM, SPP, and AECI indicated that they are monitoring the flowgates as described above.

VI. NERC IDC Tool and Policy (for a test period of June 1, 2004 to September 30, 2004)

Step 1. TLR Level 3 procedures will be used as it exists today to curtail non-firm transactions, including appropriate Level 4 reconfiguration

Step 2. If overloads still exist after step 1, prior to going to TLR Level 5, proceed to curtail remaining non-firm transactions (including Non-designated Network Resource 6-NN) using 3% as the threshold.

Step 3. After step 1 and step 2, if overloads still exist, initiate Level 5 under current TLR procedures using a 5% threshold

STATUS: MISO indicated that from June 1, 2004 to June 7, 2004 there had not been a TLR Level 5. However, MISO has been prepared to implement the applicable procedures should a TLR 5 occur. There was one instance of a TLR 5 on June 30, 2004.

[1] page 3 of the final AWTTF report

Appendix E

Consistency Between AFC/ATC Calculations and Transmission Owners' Planning Criteria

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LTATF Appendix on the Consistency Between AFC/ATC Calculations and Transmission Owners' Planning Criteria

The intent of this appendix is to discuss the concept of consistency between AFC/ATC calculations and Transmission Owners' planning criteria. The NERC ATCWG reached conclusion on the following rule as they were developing the "Transmission Capability Margins and Their Use in ATC Determination" white paper which discusses the reliability margins of TRM and CBM:

A Transmission Provider's ATC/AFC calculations, and associated margins, must be consistent with the Transmission Owners' and Public Power Entities documented Planning Criteria

This rule was incorporated into the "Transmission Capability Margins and Their Use in ATC Determination" white paper dated June 17, 1999 as demonstrated in the following two exerts:

- "The methodology used to derive TRM and its 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 it 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. 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"

- The methodology used to derive CBM must be documented and consistent with published planning criteria. A CBM 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. 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.

The rule was also incorporated into the existing Planning Standard for CBM and TRM as the following excerpts indicate.

- "Each Region's CBM methodology shall:
  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".

- "This Regional procedure shall:
  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".

LTATF Appendix on the Consistency Between AFC/ATC Calculations and Transmission Owners' Planning Criteria

All transmission service requests must be evaluated consistent with each Transmission Owner's planning criteria in order to maintain reliability. Transmission service requests must not be subject to evaluation scenarios that exceed or are 'beyond' the applicable planning criteria. For example, if the most extreme event a Transmission Owner plans for were single contingencies, it would be inconsistent with the applicable planning criteria to evaluate a transmission service request to meet a double contingency test. In this instance, evaluating a transmission service request using double contingency analysis would be in conflict with the planning criteria and would not be compatible with the reliability requirements used to serve native connected load. In an ATC calculation the following components determine the loading on a flowgate for the period of time under evaluation:

1. Base Case Flows (which recognizes the forecasted load connected to the transmission network and planned system topology)
2. Impacts of existing transmission service reservations -- both positive and negative (i.e. counterflow)
3. TRM (consistent with applicable Planning Criteria)
4. CBM (consistent with applicable Planning Criteria)

When these four components are applied to a flowgate the result is a calculated AFC. If the resultant AFC is negative, the result indicates that the flowgate is projected to be overloaded because of the preexisting commitments (i.e. the four components listed above). In some cases negative AFC values exist for future years preventing transmission customers from obtaining transmission reservations for these future time periods.

The inconsistency between Transmission Provider's AFC/ATC calculations and the Transmission Owner's Planning criteria becomes evident when the Transmission Owner internal planning processes does not result in identification of system deficiencies requiring system expansion – even on Flowgate determined by the Transmission Provider to have negative AFC values far into the future. The likely cause of this discrepancy is that the TO is not applying the same scenario, including the same transmission uses (i.e. confirmed reservations), or consistent margins (TRM/CBM) in its internal planning process as is occurring in the ATC calculations. The following questions need to be answered affirmatively for the two processes to be consistent:

1. Are base case flows, impact from reservations, TRM and CBM that are all forecasted to occur simultaneously being considered in the planning process as they are in the ATC process?
2. Are the same counterflows being considered in the two processes?
3. Are the same positive impacts being considered in the two processes?
4. Are the components of TRM being considered in the planning process in a similar manner as the ATC process?
5. Is CBM being considered in the planning process in a similar manner as the ATC process?

Any new standard on ATC calculations and its margins of CBM and TRM need to address this issue. These revised standards must require consistency between the applicable Planning Criteria and ATC process. The consistency needs to be reviewed to ensure that what is applied in ATC calculations is being planned for by the TO. TOs may determine that they do not want to plan for 100% of positive impacts from reservations and may want to use varying amounts of counterflow on various flowgates.
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Appendix F

CBM Redefinition Options

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LTATF Appendix on Redefinition Options for CBM

CBM Applicability in an RTO Environment

Earlier in the development of this industry, there were predominately 'local' vertically integrated electric utilities. Each utility built sufficient generation to serve its own load responsibility. Transmission Interconnections with neighboring utilities were typically established for one of the following reasons:

1. To minimize duplication of transmission (i.e. tie to neighbor for transmission reliability instead of extending 'local' transmission system)
2. An economic decision to build transmission instead of generation based on the generation reliability criteria the utility planned for (i.e. tie to neighbor to facilitate emergency imports to meet generation reliability criteria).

This second reason is the origin of the CBM concept. Transmission interconnections provide each interconnected system with access to their neighbors so that in the event of an extreme generation outage within a utility, that temporarily generation deficient utility could have access to 'emergency' generation resources from their interconnected neighbors. CBM is the quantification of this use of the transmission system. Therefore, CBM is an 'emergency' use transmission quantity and only 'exists' on the importing system for use only during periods of an emergency generation deficiency when firm transmission service is not available (i.e. Firm ATC is insufficient to meet emergency import requirement). Just as transmission capacity is preserved for the transmission contingencies a utility planned for, transmission capacity is also preserved for the generation contingencies that are planned for. In either case, the utility customers paid for the transmission capacity that was installed to maintain the reliability level that is planned for, via their rates for service.

With the advent of RTOs, which result in essentially huge Control Areas/Transmission Service Providers, the amount of generation within the boundaries of these huge Transmission Providers is also increased – often by an order of magnitude. Although all RTOs operate the transmission system as one entity, the operational control of generation resources can vary among RTOs. Some RTOs also operate the generation as if it was one entity (i.e. a centralized dispatch) while in other RTOs each control area dispatches their own generation. As these larger organizations are created, the concept of CBM must be reexamined. For example, if two neighboring vertically integrated utilities combine (either by merger, or RTO membership), does the CBM between the previously 'independent' systems continue to 'exist' in the same manner as determined historically? Or is CBM re-determined for the larger organization, using the import capability from the sources external to the new larger organization? With the combination of utilities into RTO-type organizations, former transmission interconnections are internalized, rendering the issue: Does CBM continue to 'exist' **within** a larger organization, which historically was two or more independent utilities?

Although the concept of CBM existed since the establishment of interconnections, quantification of CBM was the result of Open Access required by FERC Order 888. The definition of CBM initially used was:

Previous Definition of CBM as per Available Transfer Capability Definition and Determination (NERC – 1996)

> *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 CBM is a more locally applied margin than TRM, which is more of a network margin. As such, to the extent a load serving entity maintains policies and procedures to reserve transfer capability for generation reliability purposes, the CBM should be included in the reserved or committed system uses in the calculation of ATC. These CBMs should continue to be a consideration in transmission system development. It is anticipated that individual load serving entities and regional planning groups will continue to address CBMs and that the NERC and Regional reviews of generation adequacy will continue to consider this capability. It is also anticipated that load serving entities will develop additional procedures for reserving transfer capability for generation capacity purposes and include these procedures in Regional planning reviews and regulatory filings as appropriate.*

The definition of CBM was refined based on a request by the NERC Planning Committee to establish a definition for CBM that all Regions agreed to. This new definition was then utilized as part of the development of the NERC Planning Standards. The current definition determined by the NERC ATCWG and agreed to by all Regions is:

Current Definition of CBM as per NERC Planning Standards (2001)

> *Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission 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*

However, the definition currently in use still refers to CBM as an emergency import quantity and is silent of existence of CBM within or between parts of an RTO-type organization. If CBM does exist within an RTO-type organization, how are these internal quantities determined? How would this 'internal' CBM be used? If several formerly independent utilities combine into an RTO-type organization, can CBM continue to exist within this new larger organization? If so, how is a generation emergency within a portion of an RTO-type organization defined?

Redefinition options for CBM

Option 1: Retain the existing definition of CBM. The implication of retaining the existing definition is that CBM continues to be only an import quantity, and does not exist 'within' or 'between' geographical areas of an RTO-type footprint. If this concept is ratified, CBM would exist for RTOs only as import to the entire RTO footprint. Therefore the amount of CBM use would tend to be much smaller than currently. However, to the extent a generation deficiency within an RTO-type footprint was replace with generation located elsewhere in the RTO, it would be considered a change in internal generation dispatch, and therefore be considered TRM.

Option 2: Change the definition to explicitly recognize CBM as applicable 'within' or 'between' geographical areas of an RTO-type footprint. For Example:

> Capacity Benefit Margin (CBM) is the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems ***external and/or internal to that transmission provider*** 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.

If Option 2 is accepted by the industry, several associated issues must be addressed;

1. How does the RTO-type organization determine the 'subregions' to calculate CBM? By load and or generation within an area? Historical company boundaries? Groupings of historical company boundaries? Other? How to develop without being arbitrary?

2. How does the CBM 'rights' of an LSE change when the footprint of the Transmission Service Provider changes?

Long-Term AFC/ATC Task Force (LTATF) Roster

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When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Revision to Existing Standard Number MOD-001-0, MOD-002-0
Request Date	

SAR Requestor Information	**SAR Type** (Put an 'x' in front of one of these selections)	
Name LTATF	☐	New Standard
Primary Contact Steve Dayney	x	Revision to existing Standard
Telephone Fax	☐	Withdrawal of existing Standard
E-mail	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

This request changes existing modeling standard(s) by adding a requirement for transmission providers to coordinate the calculation of ATC and requires that specific reliability practices be incorporated into the ATC calculation and coordination methodologies. Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity. This request adds a requirement for documentation of the methodologies used to coordinate ATC. In addition, a requirement is added for the enhanced documentation of the calculation methodology.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐**X**	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Owner	Owns and maintains generation unit(s)
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Pending resolution of the FMSCTF, might also apply to Transmission Planner and Planning Authority and Reliability Regions.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*	
☐x	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐x	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐x	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

Definitions of Terms used in standard:

Strawman Definitions:
The Drafting Team should finalize the definitions
Total Transfer Capability (TTC):

TTC and ATC are defined in standard 1E1
Existing Transmission Commitments (ETC)
ATC is expressed as:
ATC = TTC – Existing Transmission Commitments) – CBM – TRM

Flowgate is the name given to the transmission element(s) and associated contingency(ies) if any, that may limit transfer capability.

Flowgate Criteria – to be determined

Available Flowgate Capability (AFC)
AFC is expressed as:
AFC = [to be finalized by SARDT]

The relationship between ATC and AFC is as follows:

$ATC_{(\text{Path A-B})}=AFC_{(\text{Most Limiting Flowgate for Path A-B})}/\text{Distribution Factor}_{(\text{Path A-B on Limiting Flowgate})}$

Daily, Monthly, Yearly TTC

Daily, Monthly, Yearly ATC

Daily, Monthly, Yearly TRM

Daily, Monthly, Yearly CBM

From existing standard, as recommend by LTATF

- Requirement 1 (R1). Each Region, RTO and ISO in conjunction with its members, shall develop and document a TTC and ATC (which may include the calculation of AFC) methodology.

  If an RRO's members AFC, TTC and ATC values are determined by a RTO or ISO, then a Regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a Regional methodology.

  Each transmission provider not associated with an RTO or ISO shall comply with the methodology developed by its respective reliability region.

(M1)This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

Each TTC and ATC methodology shall (S1):

a) Include a narrative explaining how TTC and ATC values are determined and in evaluating a transmission service request and made available to customers. In addition, an explanation for all items listed here must also be included of any process that produces values that can override the TTC, AFC and ATC values.

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. An explanation must be provided on how reservations that exceed the capability of the specified source point are accounted for. (e.g. 500 MW of transmission service exists in each of three directions sourced from a generator with a capacity of 500 MW).

c) Account for the ultimate points of power injection (sources) and power extraction (sinks) in TTC and ATC calculations. Source and sink points are further defined in the Source and Sink Points white paper contained in Appendix B of the Final LTATF Report.

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 ATC values and postings be updated at a minimum frequency to assure proper representation of the transmission system. These values will be made available to stakeholders at a similar frequency.

f) Indicate the treatment and level of customer demands, including interruptible demands.

g) Require that the data listed below, and other data needed by transmission providers for the calculation of TTC and ATC values are shared and used. Entities requiring data should request the data as needed. (SAR DT to determine to whom this applies, who supplies – who uses). In addition, specify how this information is coordinated and used to determine TTC and ATC values. If some data is not used or coordinated, provide an explanation. The required minimum update frequency[1] for each item is listed below:

[1] The update frequency specified should allow for improvements in technology, communication, etc, that might better represent actual system conditions.

1.1.1 **Generation Outage Schedules**: Minimum 13 month time frame includes all generators (SAR DT to determine MW threshold) used in the ATC/AFC calculation). The update frequency is daily.

1.1.2 **Generation dispatch order**: generic dispatch participation factors on a control area/market basis. The update frequency is as required.

1.1.3 **Transmission Outage Schedules**: Minimum 13 month time frame, updated daily for all bulk electric system facilities that impact ATC/AFC calculations; updated once an hour for unscheduled outages. (SAR DT should consider both pending and approved outages)

1.1.4 **Interchange Schedules** : The update frequency is hourly.

1.1.5 **Transmission Reservations**: The update frequency is daily.

1.1.6 **Load Forecast**: supplied via the SDX(or similar method), includes hourly data or peak with profile for the next 7-day time frame. The update frequency is daily. **In addition, daily peak for day 8 to 30 updated at least daily, and monthly for next 12 months updated monthly.**

1.1.7 **Flowgate AFC:** Firm and non-firm AFC values will be exchanged between entities that have coordination agreements. Unless otherwise specified in the coordination agreement, the minimum update frequency is as follows: Hourly AFC once-per-hour, Daily AFC once-per-day and Monthly AFC once-per-week.

1.1.8 Flowgate rating: Seasonal flowgate ratings will also be provided. Updated as required.

1.1.9 Calculation **model**: Updated model will be made available to neighboring/affected calculators.

1.1.10 Flowgates and flowgate definitions/criteria should be exchanged with neighboring/affected calculators on a seasonal basis, or more often as required to represent actual system conditions.

(SAR DT should discuss establishing defined criteria for establishing flowgates consistent with regional operating and planning practices)

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 assumptions used for positive impacts and counterflow of transmission reservations, including the basis for the assumptions.

k) Describe assumptions used for generation dispatch for both external and internal systems for base case dispatch and transaction modeling , including the basis for the assumptions.

l) Ensure that the TTC/ATC calculations are consistent with the Transmission Owner's/Transmission Planner's (leave FM designation to SAR DT) planning and operating criteria . (SAR DT see white paper dealing with consistency with planning criteria)

m) Describe the formal process for the RRO to grant any variances to individual transmission providers from the Regional TTC/ATC methodology.

- Any variances must also be approved by NERC or its designate

Each 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 TTC and ATC methodology shall be available on a web site accessible by NERC, the Regions, and the stakeholders in the electricity market.

M3. (SDT to develop procedures for audit to ensure adherence to stated methodology)

Below is one suggested methodology from LTATF:
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. A review to verify that the ATC/TTC calculations are consistent with the TO's/TP's planning criteria is also required. RTOs and ISO will also be required to perform this review of consistency with planning criteria and document the results. The procedure used to verify the consistency must also be documented in the report. Documentation of the results of the most current reviews shall be provided to NERC within 30 Days of completion.

M4. Each entity responsible for the TTC and ATC methodology, in conjunction with its members and stakeholders, shall have and document a procedure on how stakeholders 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 stakeholders in the electricity market.

The RRO must review and approve the RTO or ISO ATC/TTC methodology to ensure it is consistent with the RRO's Planning and Operating Criteria.

The RRO or RTO/ISO is responsible for ensuring that TTC and ATC calculations are consistent with the individual TOs/TPs planning criteria.

Each procedure shall specify:

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.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

When completed, email to: gerry.cauley@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Revision to Version Standards MOD 004, MOD005, MOD006, MOD 007, MOD 008, and MOD 009
Request Date	

SAR Requestor Information	**SAR Type** (Put an 'x' in front of one of these selections)	
Name LTATF	☐	New Standard
Primary Contact Steve Dayney	☐ X	Revision to existing Standard
Telephone Fax	☐	Withdrawal of existing Standard
E-mail	☐	Urgent Action

Purpose/Industry Need (Provide one or two sentences)

The LTATF passed the following strawman by a vote of 15 to 2:

Because the LTATF debated at length the merits of CBM calculation and utilization, the LTATF asks the SAR Drafting Team (SAR DT) to consider whether the calculation and/or withholding of CBM as an explicit quantity is necessary for reliability and should be part of a reliability standard. (please also see appendix F to the Final LTATF report)

If the industry still considers CBM to be necessary, the SAR DT is asked to consider the following recommendations:

If yes, then the existing standards on CBM should be revised to require crisp and clear documentation of the calculation of CBM and make various components of the methodology mandatory so there is more consistency across methodologies.

Additionally, the existing standards on TRM should be revised to require crisp and clear documentation of the calculation of TRM and make various components of the methodology mandatory so there is more consistency across methodologies.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies by double clicking the grey boxes.)*		
☐	Reliability Authority	Ensures the reliability of the bulk transmission system within its Reliability Authority area. This is the highest reliability authority.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐x	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Owner	Owns and maintains generation unit(s)
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Applicability to be determined by SAR DT.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check boxes for all that apply by double clicking the grey boxes.)*		
x☐	1.	Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2.	The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐x	3.	Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4.	Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐x	5.	Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐x	6.	Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified and have the responsibility and authority to implement actions.
☐	7.	The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box by double clicking the grey area.)*	
1.	The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2.	An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3.	An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4.	An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5.	An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft, modify, or withdraw a Standard based on this description.)

M1. Each Region, RTO and ISO in conjunction with its members shall develop and document a CBM methodology. This methodology shall be available to NERC, the Regions, and the stakeholders in the electricity market.

If a RRO's members CBM values are determined by a RTO or ISO, then a Regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a Regional methodology.

Each transmission provider not associated with an RTO or ISO shall comply with the methodology developed by its respective reliability region. (S1)

Each CBM methodology shall (S1):

a) Specify that the method used to determine generation reliability requirements as the basis for CBM shall be consistent with the respective generation planning criteria.

b) Specify the frequency of calculation of the generation reliability requirement and associated CBM values.
   - Require that the calculations must be verified at least annually.
   - Require that the dates seasonal CBM values apply must be specified.

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.
SAR DT should discuss whether CBM should be an explicit reservation and how/if it would be made a requirement. Also, whether the reservations would be a business practice?

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).
SAR DT should discuss whether there could be a reciprocal agreement for the use of CBM.

e) Describe the inclusion or exclusion rationale in the CBM calculation 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. The following rationale must be included in all methodologies:
   - All generation directly connected to the transmission provider's system being used to serve load directly connected to that system will be considered in the CBM requirement determination.
   - The availability of generation not directly connected to the transmission provider's system being used to serve load directly connected to that system would be considered available per the terms under which it was arranged.

f) Describe the inclusion or exclusion rationale for generation connected to the transmission provider's system.. The following rationale must be included in all methodologies:

- The following units shall be included in the CBM requirement determination because they are considered to be the installed generation capacity, committed to serve load, directly connected to the transmission system for which the CBM requirement is being determined:

  1. Generation directly connected to the transmission provider's system but not obligated to serve load directly connected to that system, will be incorporated into the CBM requirement determination as follows:

     a) Generation directly connected to the transmission provider's system, but committed to serve load on another system, will not be included in the CBM requirement determination for the transmission system to which the generator is directly connected.

     (<u>Note to SAR DT</u> – Ensure that this would be consistent with any pending resource adequacy SAR.) These units are not included because they are committed to serve load on another system and therefore not available to serve load on the system for which the CBM requirement is being determined.)

     b) Generation directly connected to the TSP's system, but not committed to serve load on any system, will be included in the CBM requirement determination for the transmission system to which the generator is directly connected as follows:

        1. The TSP will use the best information available to them (i.e. confirmed or requested transmission service/no service) to determine how these units should be considered in the CBM requirement determination. All assumptions made must be documented and approved by the entity responsible for the methodology.

g) Describe the formal process and rationale for the Region to grant any variances to individual transmission providers from the Regional CBM methodology.

- Require any variances must also be approved by NERC or its designate

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 any adjustments to CBM values to account for generation reserve sharing arrangements (i.e. Use of CBM and a reserve sharing event simultaneously occurring that is not planned for). Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

<u>SAR DT should consider paragraph below</u>:

k) Require that CBM be based on the required or recommended planning reserve. In other words, a load serving entity that does not arrange for resources at least equal to the recommended or required planning reserve levels does not benefit by causing a higher CBM.

<u>The SAR DT should consider the option below:</u>

Require that the appropriate entities will plan and reinforce the transmission system for the amount of CBM being preserved.

The most recent version of the documentation of each entity's CBM methodology shall be available on a web site accessible by NERC, the Regions, and the stakeholders in the electricity market

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 stakeholders. Documentation of the results of the most current Regional reviews shall be provided to NERC or its designate within 30 days of completion. (S1)

- The RRO must review and approve the RTO or ISO methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO or RTO/ISO is responsible for ensuring that CBM calculations are consistent with the individual TOs planning criteria.
- SAR DT - Would the above be applicable to the Planning Authority?

The CBM review procedure shall:

a) Indicate the frequency is at least annual, 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 stakeholders .

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. The procedure must specify how the consistency would be verified.

The SAR DT should consider the option below:

d) Require verification that the appropriate entities are planning and reinforcing the transmission system for the amount of CBM being preserved. The procedure must specify how the verification would be determined. RTOs and ISOs must also perform this verification and report on the findings as specified below.
e) Require CBM values to be updated at least annually and available to the Regions, NERC, and stakeholders 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 sent to NERC within 30 days of completion

Use of CBM

- Use of CBM should be addressed under business practices and not be part of this standard

TRM

M6. Each Region, RTO and ISO in conjunction with its members, shall develop and document a TRM methodology. This methodology shall be available to NERC, the Regions, and the transmission users in the electricity market. If a RRO's members TRM values are determined by a RTO or ISO, than a Regional methodology is not required for those members. RRO members not covered by an RTO/ISO would be required to have a Regional methodology. (S2) use same wording as above.

Each TRM methodology shall (S2):

a) Specify the update frequency of TRM calculations.
- Require that calculations be verified at least annually if determined to be required
- Require that dates that seasonal TRM values apply must be specified

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.

- Additional detail on how variations in generation dispatch are handled from intermittent generation sources such as wind and hydro, need to be provided

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.

- Any variances must also be approved by NERC or its designate

f) Describe the methodology and conditions thereof that are used to reflect if TRM is reduced for the operating horizon,.

g) Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

SAR DT should consider paragraph below:

h) Specify TRM methodologies and values must be consistent with the approved planning criteria. Require that the appropriate entities will plan and reinforce the transmission system for the amount of TRM being preserved. The methodology must specify how the verification of the consistency would be determined.

Each TRM methodology shall address each of the items above and shall explain its use, if any, in determining TRM values. Other items that are entity specific or that are considered in each respective methodology shall also be explained along with their use in determining TRM values.

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 updated at least annually and available to transmission users. Documentation of the results of the most current Regional reviews shall be provided to NERC within 30 days of completion. (S2**)**

The SAR DT should consider ways to ensure adherence with the paragraph below:

- The RRO must review and approve the RTO or ISO methodology to ensure it is consistent with the RRO's Planning Criteria. The RRO or RTO/ISO is responsible for ensuring that TRM calculations are consistent with the individual TOs planning criteria.

The TRM review procedure shall:

a) Indicate the frequency is at least annual, 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 stakeholders.

c) Require review of the consistency of the transmission provider's or Transmission Owner'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. RTOs and ISOs must also perform this review and report on the results. The review process used by a RTO or ISO also needs to be documented.
    - Explain how the simultaneous application of CBM and TRM amounts being implemented in the ATC calculations are being taken into consideration during the planning process.

    SAR DT to review paragraph below:

    - TRM methodologies and values must be consistent with the applicable planning criteria

    - The methodology must specify how the verification of the consistency would be determined

d) Require TRM values to be verified at least annually and made available to the Regions, NERC, and stakeholders.

e) 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 within 30 days of completion.

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	

Related NERC Operating Policies or Planning Standards

ID	Explanation

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction
or
Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Instructions:

1. **Please fill out as much of the requested information as possible. It is mandatory to provide a contact name, phone number and fax number to which questions can be directed. If you have an electronic mailing address, please make that available as well.**

2. **Attach any information you believe is related to the request. The more complete your request is, the less time is required to review it.**

3. **Once completed, send your request to:**

Rae McQuade
NAESB, Executive Director
1301 Fannin, Suite 2350
Houston, TX 77002

Phone: 713-356-0060
Fax: 713-356-0067

by either mail, fax, or to NAESB's email address, naesb@naesb.org.

Once received, the request will be routed to the appropriate subcommittees for review.

Please note that submitters should provide the requests to the NAESB office in sufficient time so that the NAESB Triage Subcommittee may fully consider the request prior to taking action on it. It is preferable that the request be submitted a minimum of 3 business days prior to the Triage Subcommittee meetings. Those meeting schedules are posted on the NAESB web site at http://www.naesb.org/monthly_calendar.asp.

North American Energy Standards Board

Request for Initiation of a NAESB Business Practice Standard, Model Business Practice or Electronic Transaction
or
Enhancement of an Existing NAESB Business Practice Standard, Model Business Practice or Electronic Transaction

Date of Request: ___________________

1. Submitting Entity & Address:
   __Long Term ATC/AFC Task Force________________________

   ____

   ____

   ____

2. Contact Person, Phone #, Fax #, Electronic Mailing Address:

   Name : **__Steve Dayney_______**
   Title : ____________________________________
   Phone : ____________________________________
   Fax : ____________________________________
   E-mail : **_ltatf@nerc.com____________________**

3. Description of Proposed Standard or Enhancement:
   It is proposed that a single Business Practice Standard be developed related to both:

   1) the processing and evaluation of transmission service requests, which use TTC/ATC/AFC and CBM/TRM

   2) the processing and evaluation of request(s) to schedule against approved transmission service reservation(s).

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4. Use of Proposed Standard or Enhancement (include how the standard will be used, documentation on the description of the proposed standard, any existing documentation of the proposed standard, and required communication protocols):

   a. **The proposed standard will be applicable to transmission service providers to ensure that consistent practices are employed among transmission service providers when processing requests for transmission service,**

   b. **The proposed standard will be applicable to transmission service providers to ensure that consistent scheduling practices are employed among transmission service providers, and**

   c. **The proposed standard will be applicable to transmission service providers to ensure that details of the practices and procedures are available to market participants.**

5. Description of Any Tangible or Intangible Benefits to the Use of the Proposed Standard or Enhancement:

   Providing increased standardization of procedures and better informing market participants of these procedures would enhance market liquidity.

   Additionally, this should result in better utilization of the transmission system.

6. Estimate of Incremental Specific Costs to Implement Proposed Standard or Enhancement:

   t.b.d.

7. Description of Any Specific Legal or Other Considerations:

   Development of this Business Practice needs to be closely coordinated with any work undertaken by NERC that impacts the calculation and coordination of AFC/ATC.

   NERC's Long Term ATC/AFC TF (LTATF), which included NAESB participation, has identified a number of issues related to the calculation and coordination of ATC and AFC. Excerpts from the LTATF report are appended to the end of this document.

It is recommended that NAESB develop a Business Practice Standard that would ensure full disclosure as well as standardization where possible of the methodology by which Transmission Service Providers (TSPs):

- **Determine the quantity of transmission service to be made available for sale to market participants; and**
- **Accept schedules for transmission previously purchased**

In addition, in developing this methodology, each Transmission Service Provider TSP should, to the maximum extent possible:
- **Use similar models and assumptions within equivalent operating timeframes;**
- **Use models and assumptions for the sale of transmission service that are similar to those used for the planning of the transmission system;**
- **Assure comparability of service for long term firm point to point and network service customers;**
- **Assure appropriate coordination between TSPs such that the sale of transmission service by one provider appropriately reflects the impacts on affected systems.**

8. If This Proposed Standard or Enhancement Is Not Tested Yet, List Trading Partners Willing to Test Standard or Enhancement (Corporations and contacts):

   N/A

9. If This Proposed Standard or Enhancement Is In Use, Who are the Trading Partners:

   N/A

10. Attachments (such as : further detailed proposals, transaction data descriptions, information flows, implementation guides, business process descriptions, examples of ASC ANSI X12 mapped transactions):

    Please see final Long Term AFC/ATC Task Force report on the NERC website at: www.nerc.com (need to update with full URL when available)