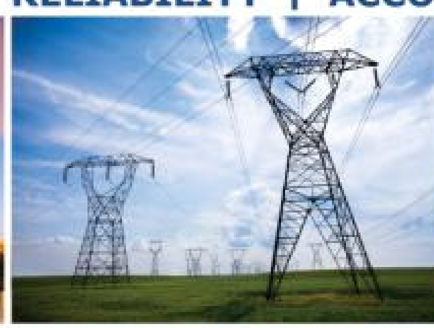
White Paper on the MOD A Standards

MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030

July 3, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

NERC Reliability Standards MOD-001, -004, -008, -028, -029, and -030 (referred to herein as the "MOD A" standards), were established in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") Orders No. 890 and 693 and were approved in Order No. 729. Collectively, the MOD A standards pertain to methodologies for the consistent and transparent calculation of Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) as follows:

- MOD-001-1a is the umbrella standard that contains the generic requirements applicable to all methods of determining ATC.
- MOD-004-1 provides for the consistent calculation, verification, preservation, and use of Capacity Benefit Margin (CBM).
- MOD-008-1 provides for the consistent calculation, verification, preservation, and use of Transmission Reliability Margin (TRM).
- MOD-028-1 provides for the development and documentation of transfer capability calculations for registered entities using the Area Interchange Methodology.
- MOD-029-1a provides for the development and documentation of transfer capability calculations for registered entities using the Rated System Path (RSP) Methodology.
- MOD-030-2 provides for the development and documentation of transfer capability calculations for registered entities using the Flowgate Methodology.

NERC initiated an informal development process to address directives in Order No. 729 to modify certain aspects of the MOD A standards. Participants were industry subject matter experts, NERC staff, and staff from FERC's Office of Electric Regulation. Questions emerged as to whether certain MOD A requirements were appropriately addressed through NERC Reliability Standards, specifically whether certain MOD A requirements addressed market or competitive issues rather than reliability issues. The group sought to reorient the MOD A standards to focus on the reliability-related aspects of ATC.

The ad hoc group decided to present a pro forma standard that consolidates the MOD A standards into a single standard covering only the reliability-related impact of ATC and AFC calculations, such as the need for Transmission Service Providers (TSPs) to implement their ATC calculations in a consistent manner and share ATC data with neighboring TSPs or other entities who need such data for reliability purposes. The consolidated approach is intended to maintain NERC's focus on developing and retaining requirements that support the reliable operation of the bulk power system (BPS).

The pro forma standard covers the Total Flowgate Capability (TFC) Total Transfer Capability (TTC) and methods and what must be included within them. It also calls for each TSP to prepare, keep current, and implement an Available Transmission Capability Implementation Document (ATCID) that describes its method for calculating ATC or AFC values. The pro forma standard calls for each TSP to prepare, keep current, and implement a Capacity Benefit Margin Implementation Document (CBMID) that describes its method for establishing margins to protect system reliability during a declared Energy Emergency Alert 2 (EEA 2) or higher. Further, it calls for each Transmission Operator (TOP) to prepare, keep current, and implement a Transmission Reliability Margin Implementation Document (TRMID) that describes its method for establishing margins to protect system reliability. The three requirements are not overly prescriptive, regardless of which method the entity uses to calculate available transmission system capability. This follows the approach of consolidating the existing standards into one pro forma standard. Lastly, the pro forma standard covers information and data sharing requirements for registered entities that demonstrate a reliability need. The two information and data sharing requirements call for what makes a request valid, the time an entity has to respond to a valid request, and other language to address confidentiality concerns.

The ad hoc group recognizes, however, that even if certain MOD A requirements do not address reliability issues and would not be included in the pro forma standard, those requirements may be essential for market or competition purposes and could be transitioned to an organization other than the Electric Reliability Organization (ERO), such as the North American Energy Standards Board (NAESB), that focuses on market-based standards. The implementation plan for the consolidated standard will cover such a transition.

As detailed below, the MOD A informal ad hoc group discussed each of the outstanding directives from FERC Order No. 729 to determine which directives continued to apply to the consolidated reliability standard and need to be addressed therein, and which was applicable to a market-based element of the current standard and would be more appropriately addressed by the organization that would eventually take over these standards.

Purpose

The purpose of this white paper is to provide background and technical rationale for the proposed revisions to the group of approved MOD standards that have a common mission of delineating rules around information on the transparency of bulk energy transfers and transmission availability.

This document outlines the next generation of these standards and proposes to combine the reliability components in this package of standards into one standard. The remaining requirements in this package would either be retired as administrative, captured as instructional or explanatory in a white paper, or could be transferred from the NERC Reliability Standards to another regulatory standards body, such as NAESB. This is appropriate as requirements with a commercial or business focus are not within the ERO's jurisdiction and are better aligned for long-term maintenance outside of the NERC Reliability Standards and reduce the NERC standard to the core reliability concepts regarding TTC, TFC, ATC, AFC, CBM, and TRM.

This white paper lays out a common understanding of industry perspectives on topics included in these standards. It further provides an explanation of how each of the outstanding FERC directives assigned to these FERC approved standards are being addressed by NERC and suggests how they could be addressed if they are owned by NAESB or another regulatory standards body. This paper will also provide technical justifications and support for the proposed requirements that are retained and placed into the pro forma standard. The contents of this paper are intended to assist the standard drafting team assigned to MOD A and industry stakeholder participants with background information to move this standard package along in the formal development process. Eventually, following industry and the NERC Board of Trustees' adoption of the proposed standard, this white paper will be used to support the filing to the applicable regulatory authorities.

History of the MOD A Informal Development

Ad Hoc Group Meetings

The first informal meeting of the MOD A informal development process was held February 12–14, 2013, at NERC's Washington, D.C. office. At that meeting, a small ad hoc group of industry subject matter experts (SMEs) and a FERC participant discussed the 20 outstanding FERC directives and possible resolutions to address the directives. The group members also discussed operational lessons learned since June 18, 2007. It was clear that smaller subgroups would need to focus specifically on MOD-028, MOD-029, or MOD-030, based on the methodology that was chosen in MOD-001 for calculating available transmission system capability.

The ad hoc group met again March 12–14, 2013, at NERC's Atlanta office. Members continued efforts from the first meeting, several new participants attended. A third informal meeting was held April 16–18, 2013, and the conversation focused on beginning the development of materials for submittal of the Standard Authorization Request (SAR) to the NERC Standards Committee (SC). The MOD A group met again June 4–6, 2013, at Bonneville Power Administration's office in Portland, Oregon to finalize the materials for submittal to the SC.

Additional meetings occurred with specific subgroups. The MOD-028 subgroup met at Orlando Utilities Commission in Orlando, Florida on March 5 for a one-day working session. The subgroup went through each of the requirements and identified the rationale of the requirement, the FERC directives associated with the standard, the issues associated with the requirement, and possible considerations for resolutions. A MOD-030 subgroup meeting was also held at PJM Interconnection's offices in Valley Forge, Pennsylvania on March 22, 2013 to examine MOD-030 in a similar approach. The MOD-029 subgroup met at Idaho Power in Boise, Idaho on April 11, 2013.

Industry opinions regarding reliability requirements vs. market requirements and how the two should be separated surfaced via the consensus-building approach used during this informal development process. The group went through MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, and MOD-030 and discussed that most of the requirements are market-based and do not belong in the NERC Reliability Standards. Discussions on this matter are described in detail later in this paper.

Other Outreach

Informal development for MOD A yielded different opportunities for outreach to industry at large. There were numerous working groups, task forces, NERC Board standing committees, compliance forums, and other workshops. NERC staff and various MOD A participants presented at multiple junctures during the informal development period to keep industry participants updated regarding the progress the MOD A ad hoc group was making.

Furthermore, various representatives participated in various levels of involvement throughout the informal development for the MOD A initiative. A list of entities were reached out to during the MOD A initiative are found in Appendix B.

Technical Discussion on Various Existing Methods

This section focuses on the technical aspects of the methods for calculating available transmission system capability. It was important for the MOD A informal ad hoc group to have users of the Area Interchange, Rated System Path, and Flowgate methods all come to a common ground to meet the group's objective to consolidate the existing standards into one. Therefore, the group discussed each of the existing methods at length and developed this section of the white paper, which walks through the three methods of determining TTC, TFC, ATC, and AFC at a high level.

General Description of ATC Methods

This section contains a description of ATC or AFC methods that apply to each of the three methods for calculating ATC described in the existing MOD A standards. The general description and criteria of the methods for calculating ATC and AFC are based on:

- Documents from the previous MOD-001-1a, MOD-004-1, MOD-008-1, MOD-028-1, MOD-029-1, and MOD-030-2 standards
- The NERC document *Available Transfer Capability Definitions and Determination*[1]
- The NERC document *Transmission Capability Margins and Their Use in ATC Determination*[2]
- Decades of experience by various TOPs and TSPs participating in the ad hoc group

This paper provides a high level discussion of common understandings, practices and common language around this subject for the purpose of coordination and consistency. As such, this paper also uses terms such as source, sink, sending area, receiving area, and path in the most general of terms and they are intended as engineering or mathematical concepts, not as the defined usages of those terms.

DETERMINATION OF ATC

ATC is a prediction of the remaining amount of power that could be transferred on a path between two systems for defined system conditions. AFC is a prediction of the amount of additional power that could flow for defined system conditions over a particular flowgate, which may involve one or more paths between systems.

The MOD-028 and MOD-029 methods both develop TTC as a prediction of the amount of power that can flow reliably from one system to another. ATC values are then calculated from the following general equations, and the equations are done for both firm and non-firm values of ATC, ETC, CBM, TRM, Postbacks, and counterflows. The MOD-030 standard discusses their method of calculating ATC in the MOD-030 section.

For the MOD-028 and MOD-029 methods, ATC = TTC – ETC – CBM – TRM + Postbacks + counterflows

Where:

- ATC is the Available Transfer Capability of the transmission path for that period.
- TTC is the Total Transfer Capability of the transmission path for that period.
- ETC is the sum of existing transmission commitments of the transmission path for that period.
- CBM is the Capacity Benefit Margin of the transmission path for that period.
- TRM is the Transmission Reliability Margin of the transmission path for that period.
- Postbacks are changes to ATC due to change in use of Transmission Service for that period.
- Counterflows are adjustments to ATC as determined by the TSP.

[1] North American Electric Reliability Council, (1996, June). Retrieved from: http://www.westgov.org/wieb/wind/06-96NERCatc.pdf
[2] North American Electric Reliability Council, (1999, June 17). Retrieved from: http://www.naesb.org/pdf4/weq_oasis011513w17.pdf

DETERMINATION OF ETC

ETC can be power flows modeled in the base system conditions, discrete values accounted for in the ATC or AFC calculation, or both. The ETC value may be a sum of the actual reservation values, an “expected to be used” value, an “effect the value has on this flowgate or path” value, or a combination thereof.

ETC = NITS + GF + PTP + ROR + OS

Where:

- NITS is the capacity set aside for Network Integration Transmission Service (including the capacity used to serve bundled Load within the TSP’s area with external sources) on transmission paths.
- GF is the capacity set aside for Grandfathered Transmission Service and contracts for energy or Transmission Service, where executed prior to the effective date of a TSP’s Open Access Transmission Tariff or safe harbor tariff on transmission paths that serve as interfaces with other Balancing Authorities.
- PTP is the capacity reserved for confirmed Point-to-Point Transmission Service.
- ROR is the capacity reserved for rollover rights for Transmission Service contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer’s Transmission Service contract expires or is eligible for renewal.
- OS is the capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Transmission Service, including any other adjustments to reflect impacts from other transmission paths of the TSP.

DETERMINATION OF CBM

CBM is defined as the amount of firm TTC preserved by the TSP for an Load Serving Entity (LSE), whose Loads are located on that TSP’s system, to give LSEs access 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 TTC preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

CBM is not the same as TRM, and components that are included in TRM cannot be included in CBM. The direct beneficiaries of CBM are the LSEs that are network customers (including native Load) of a host TSP. The benefit that LSEs receive from CBM is the sharing of installed capacity reserves elsewhere in the transmission system, which translates to a reduced need for installed generating capacity and, ultimately, lower rates for customers.

CBM is the translation of generator capacity reserve margin determined by (or for) the LSEs within a host TSP into a transfer capability quantity. It is the TSP’s responsibility to make this translation and as such, the TSP may apply discretion in determining this quantity. The planned purchase of energy to serve network Load (including native Load) or meet generation reserve levels is not included in the CBM quantity. These planned purchases actually reduce the total CBM quantity. For example, if an LSE requires 4,500 MW of external resources and plans the explicit purchase of 1,000 MW, then the total CBM is 3,500 MW.

Generation Capability Import Requirement (GCIR) is the amount of generation capability from external sources identified by an LSE or RP to meet its generation reliability or resource adequacy requirements as an alternative to internal resources. The GCIR may be determined via three methods:

- Probabilistic Method — Probabilistic calculation methods, such as loss-of-Load probability, have inputs such as unit forced outages, maintenance outages, minimum downtimes, Load forecasts, etc. A typical benchmark to measure generation reserve level is a probabilistic loss-of-Load expectation of 0.1 day per year.
- Deterministic Method — Deterministic methods typically are centered on maintaining a specified reserve or capacity margin, or may be based upon surviving the loss of the largest generating unit. Typical benchmarks for the determination methodology would be a multiple of the largest generation unit within the TSP’s system.

- External Method — Reserve margin or resource adequacy requirements may be established by other entities, such as municipalities, state commissions, Regional Transmission Organizations (RTOs), Independent System Operators, (ISOs), or Regional Entities.

Regardless of method used to determine GCIR, the criteria must be applied consistently by the TSP to all LSEs. In some cases, it may be appropriate to apply both deterministic and probabilistic methods for the determination of generation reserve requirements, depending upon the time frame under consideration. For example, in the very near time frame, the degree of uncertainty associated with generating unit forced and maintenance outages should be low, and deterministic methods for the calculation of generation reserve requirements may be applied. In this example, for the longer term time frame, probabilistic methods may be applied due to the number of variables and the uncertainty associated with them.

Regardless of the methodology used, the TSP must ensure that:

1. The method used to arrive at the amount of external generation needed is consistent with applicable reliability criteria.
2. The total transmission capability reserved as CBM on all transmission paths does not exceed the requested GCIR (less any TRM component).
3. The allocation of the total CBM to transmission paths is consistent with available external generation resources, known transmission limitations, and historical transfer patterns during actual emergency generating capacity deficiency events.

The allocation of CBM to the host TSP's transmission paths must be based on the generation reserve and projected availability of outside sources and the historical availability of outside resources. The preservation of CBM on the importing TSP's system does not ensure the availability of transmission transfer capability on other systems but relies on the diversity of generation and transmission resources that may be available on a transmission path during a generation emergency.

Uses of CBM: The TSP that maintains CBM shall approve, within the bounds of reliable operation, any Arranged Interchange using CBM that is submitted by an "energy deficient entity" under an EEA 2 if:

1. the CBM is available,
2. EEA 2 is declared within the Balancing Authority Area of the "energy deficient entity," and
3. the Load of the "energy deficient entity" is located within the TSP's area.

CBM must be released on a non-firm basis when an EEA 2 is not in effect within the Balancing Authority Area of the "energy deficient entity."

DETERMINATION OF TRM

TRM is defined as the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission system will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Generally, the uncertainties associated with the operation of the interconnected electric system increase as the time horizon increases. Examples of these uncertainties are:

- Aggregate Load forecast
- Load distribution uncertainty
- Forecast uncertainty in transmission system topology (including, but not limited to, forced or unplanned outages and maintenance outages)
- Allowances for parallel path (loop flow) impacts
- Allowances for simultaneous path interactions
- Variations in generation dispatch (including, but not limited to, forced or unplanned outages, maintenance outages and location of future generation)

- Short-term System Operator response (including Operating Reserve actions)
- Reserve-sharing requirements
- Inertial response and frequency bias

The methodology used to derive TRM and its components must be documented and ideally should not account for uncertainties accounted for elsewhere in ATC calculation.

This paper's purpose is not to describe the detailed process of the calculation methodologies by which TRM is determined, but rather to delineate the thought process to derive a TRM quantity. It is a TOP's task to determine the justification and calculation methodology for any of the uncertainties listed above. To illustrate a justification and calculation methodology, two examples for determining the short-term System Operator response (Operating Reserve actions) component of TRM are given below.

- Example #1: The first method explicitly models Operating Reserves in the calculation of TTC by replacing lost generation based on a call for operating reserve sharing. If the generator contingency is more restrictive, the limit, due to implementation of the operating reserve sharing, sets the amount of TTC. If the transmission contingencies are all more restrictive, the transmission contingency limit will set the amount of TTC. If a generator contingency occurs, resulting in the need to access operating reserves, it will produce lower loadings than the transmission contingency. This method may be appropriate when monitoring all transmission facilities in the interconnected transmission system.
- Example #2: The second method simulates the loss of individual generators with replacement power modeled as a call for operating reserve sharing via power flow analyses. The maximum increased flow on a transmission path or flowgate becomes the operating reserve sharing component of TRM. This method may be more appropriate when monitoring a limited number of facilities or flowgates similar to the TRM applied by transmission path.

Area Interchange Method – MOD-028

PROCEDURE FOR CALCULATING AREA INTERCHANGE METHOD

Determination of TTC in the Area Interchange method is based on predicting the system response to power flowing from one area of the system to the other. This prediction is made by stressing the system with appropriate transfers under critical contingencies to determine the response of the transmission system.

When power is transferred between two areas (such as Area A to Area F in the figure below), the entire transmission system responds to the transaction. The power flow on each transmission path will change in proportion to the response of the transmission path to the transfer. Similarly, the power flow on each transmission path will change depending on network topology, generation dispatches, customer demand levels, other transactions through the area, and other transactions that the transmission path responds to that may be scheduled between other areas.

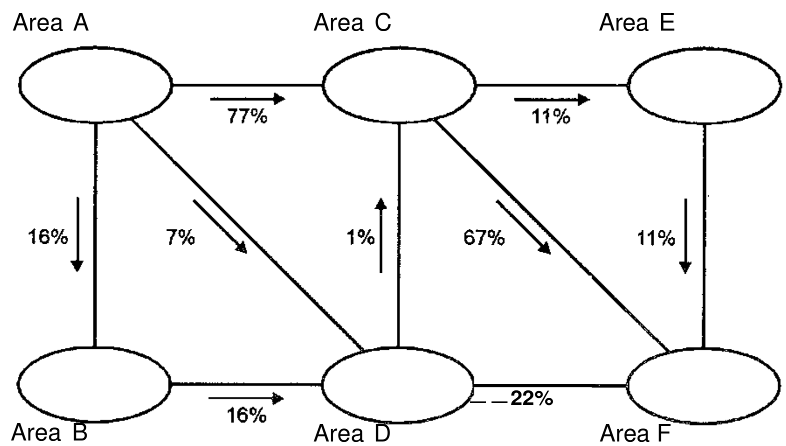


Figure 1. Response for Area A to Area F Transfers

Transmission studies are performed to determine the transfer capability from Area A to Area F. During the studies, it is determined that 77% of power transfers from Area A to Area F on the transmission path between Area A and Area C. In this example, 160 MW of pre-existing power flows from Area A to Area C due to generation dispatch and the location of customer demand centers on the modeled network. When a 500 MW transfer is scheduled from Area A to Area F, an additional 385 MW (77% of 500 MW) flows on the transmission path from Area A to Area C, resulting in a 545 MW power flow from A to C (385 MW + 160 MW). To determine the ability of the transmission system to transfer power from Area A to Area F, additional potential impacts within the individual area must also be recognized. The transmission system responses shown in Figure 1 must be expanded to consider possible transmission limits within each area. Recognition of the limiting element responses within the individual areas for Area A–Area F transfers increases the complexity of determining the Area A–Area F transfer values.

TRANSLATION OF SYSTEM IMPACTS TO TTC

TTC is a function of total capacity availability on the most limiting transmission facility that allows for single facility and, in some cases, multiple facility contingencies. To determine TTC, the Incremental Transfer Capability (ITC) is first determined. ITC the measure of, from a certain starting system condition, how much additional capacity can be transferred from Area A to Area F before pre- or post-contingency limit(s) are reached. Once this ITC limit is found, it is combined with the existing transfers from Area A to Area F, referred to as the "impact of firm," to come up with the total transfer capability between the areas based on simulation. The TTC used to determine ATC must also be lower than the contractual rights (for example sum of ties), and lower than any predetermined SOL or IROL value for that path or a combination of paths. The TTC value may also have to consider other obligations that may limit its value; for example, if multiple paths share an interface limit and each has an allocated portion of that interface limit, the allocated portion of the interface limit may be lower than the calculated value. So the TTC value used to determine ATC is the lowest of these values.

TTC is the lowest of:

- ITC value + impact of firm
- Contractual rights (sum of ties, contracts)
- Agreed-upon allocations
- SOL or IROL value previously determined through other studies

ATC TIME VARIATION AND NETWORK DEPENDENCY

Network conditions will vary over time, causing the resultant ATC of the network to change. Also, the most limiting facility in determining the network's ITC can change from one system condition to another. Therefore, the ATC of the network changes as the expected conditions for the time period under study changes, or the time period being evaluated changes.

ADDITIONAL COMMENTS ON DETERMINATION ON AREA INTERCHANGE METHOD OF TTC

The major points for determining a Network Response Total Transfer Capability are outlined below.

1. System Conditions: Base system conditions are identified and modeled for the period being analyzed, including projected customer demands, generation dispatch, system configuration, and base scheduled transfers. As system conditions change, the base system conditions under which TTC is calculated may also need to be modified.
2. Critical Contingencies: During transfer capability studies, many generation and transmission system contingencies throughout the network are evaluated to determine the most restrictive contingency(s) to the transfer being analyzed. The contingency evaluation process includes a variety of system operating conditions, because the most critical system contingencies and their resulting limiting system elements vary.
3. Parallel Path Flows: Parallel path flows occur as a result of power transferred in the ac network. This complex transmission system phenomenon can affect one or more Area's transmission line(s), especially those Areas electrically near the source or sink of the loop flow. As a result, transfer capability determinations must be sufficient in scope to ensure that limits throughout the transmission system are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the Area with the source and sink, which can limit the transfer capability between those two areas.
4. Non-Simultaneous and Simultaneous Transfers: Transfer capability can be determined by simulating transfers from one area to another independently and nonconcurrently with other area transfers. These capabilities are referred to as "nonsimultaneous" transfers. Another type of transfer capability reflects simultaneous or multiple transfers concurrently. These capabilities are developed in a manner similar to that used for non-simultaneous capability, except the interdependency of transfers among other areas is taken into account. These interdependent capabilities are referred to as "simultaneous" transfers. No simple relationship exists between non-simultaneous and simultaneous transfer capabilities. The simultaneous transfer capabilities may be lower than the sum of the individual non-simultaneous transfer capabilities.
5. Maximum Adjustment Applied: Depending on the exact method of determining an ITC value, the calculation may run out of adjustments to make (Load or generation) without finding a constraint to ITC. At this point, the ITC value may be set at the maximum amount tested, the Maximum Adjustment Applied value. If the Maximum Adjusted value is the ruling factor in the end ATC value, the value should be high enough that the end ATC value does not constrain the market.

Rated System Path Method – MOD-029

OVERVIEW

The RSP method for ATC calculation is typically used for transmission systems that are characterized by sparse networks with customer demand and generation centers distant from one another. Generally in this approach, transmission paths between areas of the network are identified and appropriate system constraints determined. ATC is computed for these identified paths and interconnections between TSPs.

The current RSP method defined in MOD-029 is generally developed from the WECC RSP method. The process of determining the TTC is currently based on operating horizon simulated power flow: either no reliability limit is achieved, or reliability limit is achieved. This has been identified as an issue in the current MOD-029. Generally, the RSP method involves three steps:

1. determining the path's TTC;
2. allocating the TTC among owners in a multiowned path to determine the owners' rights; and
3. calculating ATC for each right-holder by subtracting each of their uses from each of their individual TTC rights.

With regard to the regional path (such as a WECC Rated Path), wide-area coordination is achieved by developing the TTC in a manner that follows a regional review process. This process assures individual, power pool, subregional and regional coordination and the necessary consideration of the interconnection network's constraints and conditions. While this coordination could be achieved for a system intact (all lines in service) and a specific set of planned outages, it is very difficult to ensure that the TTC for all paths (including internal paths) is always coordinated for the time horizon for those RSPs, because system topology changes with all the planned outages, demand forecasts, and generation schedules. The RSP method includes a procedure for allocating TTC, and in turn ATC, among the owners of the transmission paths.

UNSCHEDULED FLOW OR PARALLEL PATH FLOW

The RSP approach to calculating TTC may or may not account for the effects of unscheduled flow (parallel path flow) on interconnected systems through the modeling of realistic customer demand and generation patterns in advance of real-time operations. It uses a maximum power flow test to ensure that the transfer path is capable of carrying power flows up to its rated transfer capability or TTC.

The rating process begins by modeling the interconnected network with the actual flow that will occur on the path and its parallel paths under realistically stressed conditions. The lines comprising the path may be rated and operated as a single path. The network is tested under a wide range of generation, customer demand, and facility outage conditions to determine a reliability-based TTC. When determined this way, the TTC rating usually remains fairly constant except for system configuration changes such as a line outage. To implement the RSP method, consistent path rating methods and procedures must be agreed upon and followed within the interconnection.

Nonsimultaneous ratings are normally used as the basis for calculating ATC. If, however, two rated paths have a simultaneous effect on each other, the rating process identifies the simultaneous capabilities or establishes nomograms that govern the simultaneous operation of the paths. Applicable operating procedures are negotiated to ensure reliable network operation. Where simultaneous operation is necessary, operator control is used to ensure safe and reliable operation of the transmission network.

TTC values are calculated for operating time horizon in some path with native and a neighboring control area's forecasted Loads, generation schedules, and line outages. ATC will change as a result of the operating horizon TTC changes for that time horizon. Pre-contingency limits for all facility ratings are respected while post-contingency limits are set for Long-Term Emergency (LTE) and Short-Term Emergency (STE) ratings with respect to facilities owned by a TOP and its neighboring control area's facilities.

CAPACITY ALLOCATION

The TTC of a transmission path is allocated among the right-holders based upon their negotiated agreements. The determination of the transmission rights through the allocation process is critical to the RSP implementation of ATC. The rights in the path are negotiated for each of the individual TSPs. Except for deratings based upon system operating (e.g., emergency) conditions, these allocations become rights that the right-holder may use or resell as Transmission Service.

Although the actual flows from each right-holder's schedule will flow on all parallel lines, the advance allocation of rights on a path makes it possible for right-holders to determine ATC and sell Transmission Service within their rights, independent of others. If the rating is determined using appropriate path-rating procedures, including a maximum power flow test, the potential for adverse unscheduled power flow effects is minimized.

ATC CALCULATION APPROACH

1. Each path for which ATC must be calculated is identified, and then a TTC is determined as described above. The TTC is then allocated among the owners by negotiated agreement.

2. Deratings for outages, nomograms, maintenance, or unscheduled flow are allocated, if necessary, to the right-holders based on prearranged agreements or tariffs.
3. Right-holders take their respective allocated shares of the TTC for a path and subtract the existing commitments to determine the appropriate ATC.
4. Right-holders update and repost their ATC calculations as new commitments impact their ATC. A transfer from one area to another involving several Transmission Owners (TOs) requires locating and reserving capacity across multiple paths and potentially multiple right-holders.

EXAMPLE OF ATC DETERMINATION

The following example illustrates the application of the RSP method for determining ATC in a sparse network. The example transmission system is shown in the figure below. All paths that connect the various areas have transfer capabilities that consider unscheduled flow and interconnection interactions and effects and were individually developed in coordination with all areas. The TTCs portrayed in the figure are shown for each path and are directional, but are not necessarily the same for each direction.

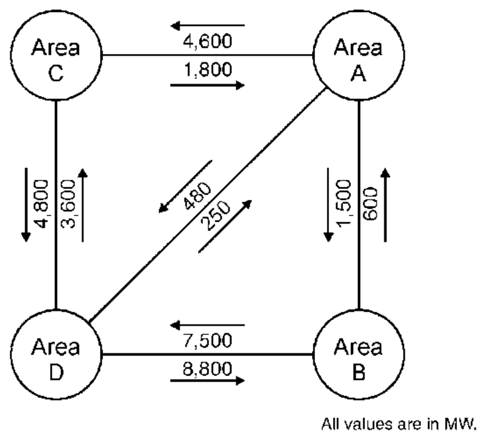


Figure 2. Example Application of Using RSP to Determine ATC in a Sparse Network

Each path may consist of several transmission lines that can have different owners. In the example shown in Figure 2, the path between Area B and Area D is comprised of five lines. The TTC from Area B to Area D is 7,500 MW and in the reverse direction is 8,800 MW. Line 1 is owned by a single entity and has an allocated portion of the TTC equal to 1,300 MW in either direction.

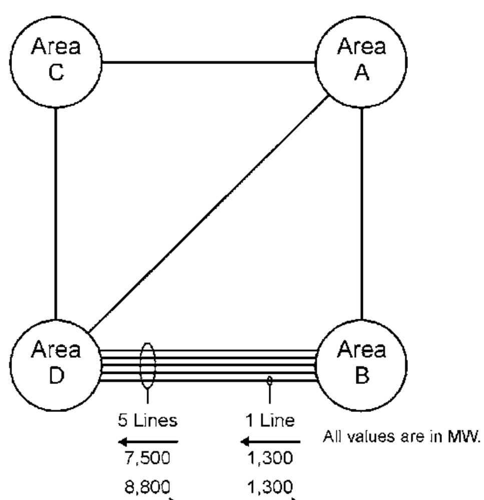


Figure 3. Example Application of using RSP to Determine ATC with Multiple Owners

The example illustrated in Figure 3 reflects a snapshot in time during the planning horizon. Initial Transmission Service reservations are shown for each path in the figure below. The corresponding ATC for each path has been calculated by subtracting the firm service from the TTC. Because all the Transmission Service reservations are assumed to be in one direction on each path, the path ATC is only calculated for that direction.

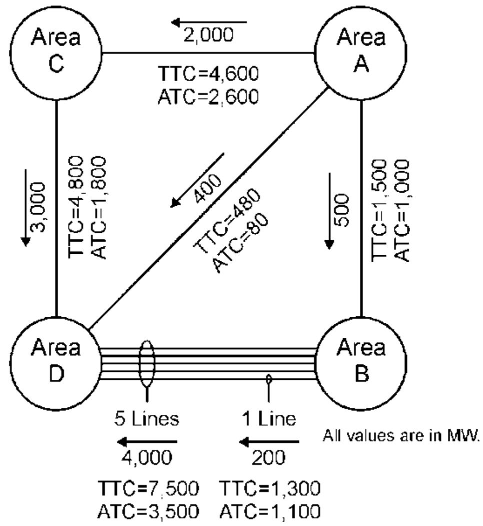


Figure 4. Example of a Snapshot in Time Using RSP to Determine ATC

In the example shown in Figure 4, the ATC from Area B to Area D is calculated as 7,500 MW less 4,000 MW, or 3,500 MW. For line 1 of the Area B-to-Area D path, the ATC is 1,300 MW less 200 MW, or 1,100 MW. In the next case, as shown in Figure 5 below, 1,000 MW of firm Transmission Service is acquired from Area A to Area B to Area D. No other changes occur. The total Transmission Service reserved from Area A to Area B is 1,500 MW, and the resulting ATC goes to zero. The ATC from Area B to Area D reduces to 2,500 MW (7,500 MW TTC less 5,000 MW reserved Transmission Service). It is assumed the 1,000 MW of the new reserved Transmission Service was obtained from the owner of line 1, resulting in the total reserved Transmission Service on this line being 1,200 MW. The new ATC for line 1 is 100 MW (1,300 MW TTC less 1,200 MW reserved Transmission Service).

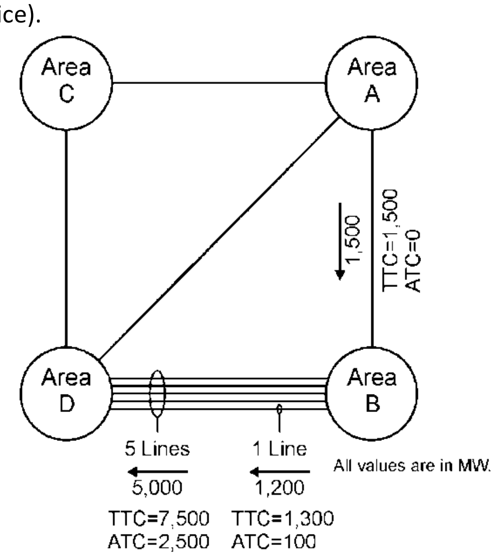


Figure 5. Example of a Snapshot in Time Using RSP to Determine ATC

The non-firm Transmission Service reserved for a path in each direction may not exceed the path's transfer capability in either direction under any circumstances.

Unscheduled flow may at times preclude scheduling to a path's full transfer capability or TTC. If an internal limit is encountered in any system as a result of the transaction from Area A to Area D (for example in Area D), Area D's system operator must respond to relieve the limitation by redispatching generation or using phase shifter control. An unscheduled flow mitigation plan might also be implemented to relieve excessive unscheduled flow problems. Additional relief may be achieved by curtailing schedules that are contributing to the unscheduled flow on the path or by increasing schedules that would create unscheduled flow in the opposite direction. In this example, if the path from Area A to Area D were limiting, unscheduled flow mitigation procedures could be implemented to initiate coordinated operation of controllable devices such as phase-shifting transformers to relieve the limitation.

There are times in the operating horizon when the use of the transmission system results in actual flows on a transmission path being less than the transmission scheduled on the path. During these periods, if the transmission path is fully scheduled, additional electric power may be scheduled to Area D from Area A by reserving Transmission Service over a different transmission path. In this case, Transmission Service could be obtained from either the owners of the direct path between Area A and Area D or the owners of the transmission system from Area A to Area C to Area D.

For the RSP method, the transmission rights to be reserved and scheduled by all transmission users are consistent with the rating of the transmission paths. If determined through a coordinated process using models that capture the major effects of the interconnected network, these ratings will create limits that result in the reliable operation of the regional electric system. Through a negotiated allocation process, the owners of the transmission paths will know their Transmission Service rights, and the resulting use of these rights will be consistent with the physical capability and limitations of the transmission system.

Flowgate Method – MOD-030

PROCEDURE FOR CALCULATING FLOWGATE METHOD

The Flowgate Methodology uses a flow-based approach to calculate ATC based on a predetermined set of constraints—a subset of monitored and contingent elements called flowgates. AFC is the amount of unused transfer capability on a flowgate after accounting for base case conditions represented by solved base case flows and applying the impacts of non-base case commitments and flowgate specific margins.

The following mathematical algorithm is used to calculate AFC:

AFC = TFC – ETC – TRM – CBM + Postbacks + counterflows

Where:

- AFC is the Available Flowgate Capability for the flowgate for that period
- TFC is the Total Flowgate Capability of the flowgate
- ETC is the sum of existing transmission commitments for the flowgate during that period
- CBM is the impact of the Capacity Benefit Margin on the flowgate during that period
- TRM is the impact of the Transmission Reliability Margin on the flowgate during that period
- Postbacks are changes to AFC due to change in use of Transmission Service for that period
- Counterflows are adjustments to AFC as determined by the TSP

To calculate ATC, which represents a transfer capability in MW available for sale between a specific POD and POR, the TSP will first calculate an AFC for each flowgate. ATC is then calculated by taking the minimum AFC of the limiting flowgates per path and dividing it by the distribution factor or transfer response factor.

ATC = Minimum {AFC1 / Transfer Response Factor, …, AFCn / Transfer Response Factor}

Where *n* is the number of limiting flowgates for a specific POR and POD Pair.

ATC determination process is a multistep integrated process:

- The TSP develops and maintains seasonal models and performs AFC or ATC calculations based on them. The model builder portion of the AFC or ATC engine modifies these seasonal base cases to reflect anticipated conditions such as forecasted Load levels, outages, generation dispatch files, and base case transfers (reservations or schedules as appropriate) for the AFC or ATC time horizon. The base case is used to calculate initial AFC flowgate values and transfer distribution factors, which in turn are inputs to the ATC calculation process.
- The ATC calculation process applies the impacts of transmission reservations (or schedules as appropriate), TRM, and CBM and calculates AFC by determining the capacity remaining on individual flowgates for further Transmission Service activity. The AFC calculation uses the AFC values for selected coordinating entity flowgates that are calculated by the coordinating TSP.
- The TSP's AFC or ATC calculation implements the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the TSP accounts for firm commitments; (2) for non-firm ATC calculations, the TSP accounts for both firm and non-firm commitments.
- Using transfer response or distribution factors for the specific POR and POD pairs, the AFC–ATC calculator translates the flowgate AFC values into path ATC values for postings on the Open Access Same-Time Information System OASIS.

Flowgate Criteria

The TSP models some flowgates with contingencies and some without contingencies. The flowgates modeled without contingencies are the Power Transfer Distribution Factor (PTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition. The flowgates modeled with contingencies are the Outage Transfer Distribution Factor (OTDF) flowgates, which are flowgates where a single facility or multiple transmission facilities are monitored for a limiting condition after a contingency event has been simulated to have occurred (one or multiple facilities for the loss of another facility or facilities).

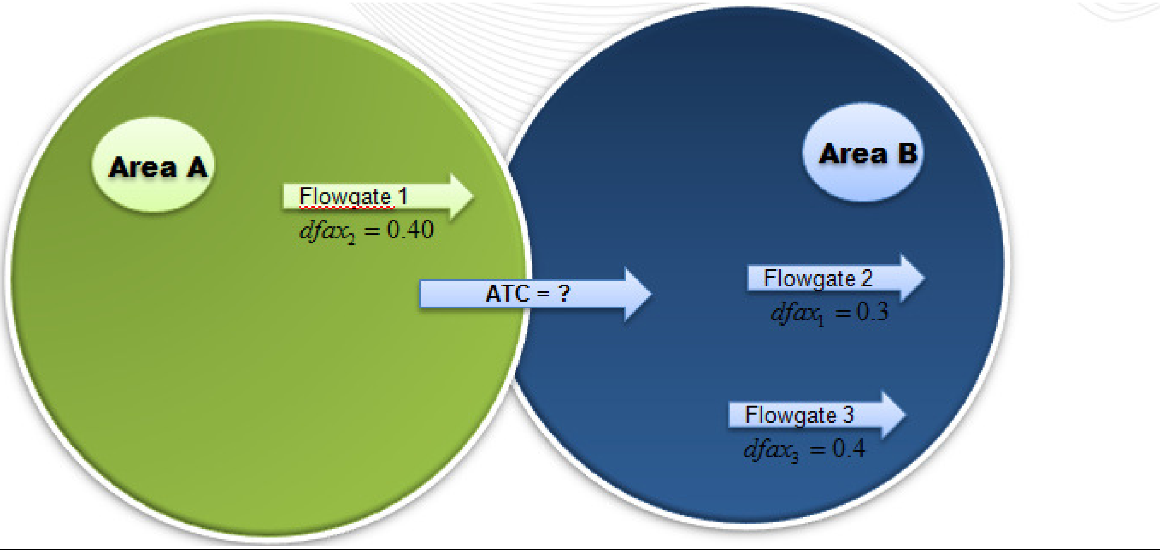
The flowgate screening process for AFC calculations includes at a minimum the top three limiting elements based on a BA–BA transfer analysis. The TSP also includes applicable SOL and IROL flowgates. In addition, flowgates with a history of Transmission Loading Reliefs (TLRs) are included in the AFC process.

The TSP also includes external entity flowgates with a 5% distribution factor in the AFC process. PTDF or OTDF is applied as appropriate to the Flowgate, as defined by the requesting TSP.

For flowgates owned by other parties, the TSP uses the limit provided by that party, subject to the terms of the AFC coordination and congestion management process sections of the applicable agreements between the TSP and the other parties.

ATC Calculation Example

The following example illustrates the application of the flowgate method to calculate ATC. The transfer between Areas A and B is limited by flowgates 1, 2, and 3. Flowgate 2, with the minimum ATC, establishes the path ATC for the specified time period. The details of the calculations are below.



$$AFC_{final} = RATING - FLOW - CBM - TRM - RESERVATION\ IMPACTS\ *$$

$$ATC = {AFC_{final}}/{dfax}$$

* Reservations not already included in the base case

$$\begin{aligned} Flowgate\ 1: AFC_1 &= 1000 - 800 - 30 - 20 - 50 = 100\ MW \\ ATC_1 &= 100/0.40 = 250\ MW \end{aligned}$$

$$\begin{aligned} Flowgate\ 2: AFC_2 &= 880 - 700 - 35 - 25 - 55 = 65\ MW \\ ATC_2 &= 65/0.3 = 217\ MW \end{aligned}$$

$$\begin{aligned} Flowgate\ 3: AFC_3 &= 800 - 500 - 24 - 16 - 135 = 125\ MW \\ ATC_3 &= 125/0.4 = 312\ MW \end{aligned}$$

Other Technical Discussions

The main discussion points raised by the informal development group are summarized below. These discussions provided the basis for the consolidation of the six MOD A standards and specifically for determinations regarding which requirements were necessary for reliability and which requirements were market-based. This section is intended to assist anyone who was not able to participate in the informal development process in understanding why the informal development resulted in the posted pro forma standard. In addition, this section will provide the standard drafting team the rationale behind the proposed changes.

Respecting and Utilizing Neighboring Systems Data

The group discussed how the industry sells Transmission Service. They determined that while the selling of service itself is not a function of system reliability, the excessive selling of transmission can create otherwise unnecessary actions by the TOP to maintain system reliability. The first step a TSP can take to ensure its calculated ATC does not impact reliability is to limit the sale of Transmission Service to within SOLs or IROLs. The second step a TSP can take is to limit the calculated ATC to within the SOLs or IROLs of neighboring TSPs, provided the sale of that service has an impact upon those SOLs or IROLs. The current MOD standards go into great detail to provide prescriptive methods for identifying those SOL or IROLs that could be impacted by transactions that result in the sale of Transmission Service.

The ad hoc group determined that any new or revised standard developed needs to retain a framework for requiring TSPs and their neighboring TSPs to share and acknowledge mutual impacts on SOLs or IROLs. This would allow the continued coordination between TSPs such that SOLs or IROLs are not intentionally violated by the sale and scheduling of Transmission Service. This type of TSP coordination is essential and provides an additional layer of situational awareness for securing the reliability of the BPS by the TOP. This is especially true in the MOD-030 standards, where the identified limits are a monitored element or contingency pair that could become an SOL or IROL or facilities that have gone through the congestion management process within the last year.

Operating the System

One of the key components of operating the transmission system is the communication and coordination of BPS SOLs and IROLs in the operating horizon. This communication and coordination allows Reliability Coordinators (RCs) and affected TOPs to have situational awareness of issues in neighboring transmission systems that may have an impact on their own transmission systems. It also allows the affected TOPs to take corrective actions necessary to mitigate the potential threat to the BPS as a result of these SOL or IROL violations.

Another key component is monitoring system conditions in the operating horizon. The TOP continuously monitors real-time activities on the BPS and verifies that their transmission systems operate within SOLs and IROLs. The TOP monitors daily operating conditions and the execution of mitigation plans in order to ensure that the corrective actions taken to mitigate SOLs or IROLs are valid. During daily and seasonal assessments, the TOPs are made aware of potential SOLs or IROLs so that mitigation plans can be developed and validated.

Any new or revised MOD standard should retain those requirements that provide for the communication, coordination, and monitoring of SOLs and IROLs.

Oversold Conditions

NERC defines ATC as a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. As such, ATC is a calculation of how much capacity a TSP is willing to make available to transmission customers, balanced against TSP and transmission customers' willingness to accept increased curtailment or redispatch risk. This risk tolerance is unique to each TSP and is based on their estimates of how much committed capacity may be used at a given point in time. Accurately estimating how transmission customers will exercise their committed capacity is becoming increasingly difficult, given the proliferation of variable resources and renewable portfolio standards that encourage customers to purchase transmission rights in excess of their needs, so that they maintain flexibility to use energy from a number of different resources.

ATC is not a prediction of unused transfer capability and, in most cases, does not directly inform the dispatch or operations of transmission systems as to system loadings. For example, a negative ATC value would not necessarily trigger corrective actions until the constraint is overscheduled, real-time system loadings approach system limits, or the system limit (SOL or IROL) is violated. The prediction of ATC values at a particular time or day changes as Load forecasts, outage plans, and other system condition forecasts change. As it approaches real time, a daily transfer sold 28 days out may vary from unconstrained market conditions, to constrained, to oversold, and back to unconstrained as forecast data changes. The service is sold based on the party's risk tolerance for curtailment and prediction of future conditions, realizing that as real time approaches, those conditions may change. While the services are sold in good faith, a service sold will not be scheduled and delivered if it will cause an SOL or IROL violation when it comes to real-time operation.

Conclusion for Revising the Standards

As discussed above, there are existing standards and practices that dictate the operation of the system. The ATC or AFC value provides a forecast of what additional capacity may be available for sale, given the current prediction of future conditions, but those values do not dictate how a system will operate. Since overselling can create the burden on TOPs to make curtailments that may have been avoidable, there is a reliability need for the TSP to disclose to the TOP, neighboring TSPs, and others how they determine that available capacity. There is also a reliability need for those calculations to respect the SOL or IROL values of the TOPs and for TSPs to share data with each other as needed to calculate ATC values. Just as existing standards do not provide the formula to solve a Load flow calculation, or how to solve for voltage given current and impedance, there is no reliability need served by having the standards prescribe a series of methods for determining ATC or AFC values. In some cases this prescriptive approach harms reliability or harms market access by either overcalculating or undercalculating the ATC or AFC value, depending on the particular approach and the system to which it is applied.

Proposed Resolution

Role of the Existing Standards

As discussed above, the role of NERC ATC and AFC standards is reliable TTC and TFC calculation, transparency in ATC or AFC calculation, and data sharing. The existing ATC- and AFC-related standards, MOD-001, MOD-004, MOD-008, MOD-028, MOD-029, MOD-030, go well beyond this role by specifying the mechanisms the TSP or TOP should use to determine the TTC, TFC, CBM, ETC, ATC, and AFC values. An entity that calculates TTC in a technically sound manner that respects the reliability limits, but doesn't necessarily follow one of the predetermined methods, would not adversely affect reliability. The high level of detail and instructions in the standards also limit the ability to innovate and find more efficient or more accurate methods of determining ATC and AFC values that may result in better reliability, better market access, or both. This high level of detail also dilutes the focus on the key reliability elements of the standards. The existing standards are also only invoked when the values are used in an ATC or AFC calculation, so a TOP that calculates TTC or TFC for use in operating its system or to support its RC would not fall under the current standard unless the values were also used for ATC calculation. Therefore, the ad hoc group proposes that the pro forma standard consolidate the reliability needs of the existing standards into a single standard.

Transition Considerations Created by Consolidation of the Existing Standards

The ad hoc group identified important considerations as it examined consolidating the MOD A standards, including what role NAESB or another organization could take in addressing requirements that were not going to be owned by NERC. These transition considerations were reliability, transparency, and consistency.

The ad hoc group discussed these transition considerations at length and came to the conclusion that for the perspective of reliability, the proposed pro forma standard does not harm BPS reliability. For the purposes of transparency, the pro forma standard maintains and may improve upon the level of transparency that the existing standards provide. For consistency, the pro forma standard does allow for more variety than the current three methods (MOD-028, MOD-029, and MOD-030) allow, but that may not be detrimental to reliability and market access. However, the ad hoc group does not believe this variety is detrimental to reliability. The role of NAESB (or another organization) in picking up where the standard drops off must still be fully determined and will be during the coming weeks, before this filing is submitted to FERC for approval.

The pro forma standard focuses on what the ad hoc group believes are the reliability needs around TTC, TFC, TRM, CBM, ATC, and AFC. Those three reliability needs are the sharing of how a value is calculated, an opportunity to influence that value, and data sharing. Across North America, there are several variations on how to determine these values based on the specific transmission system conditions, market conditions, and available data. These methods all fall broadly within the existing MOD-028, MOD-029, and MOD-030 standards and have been developed over the last several years by those knowledgeable in how their transmission systems respond to stimuli. Since no single method provides the right balance of reliability and market access for all areas, attempting to provide a single method, or even three single methods of instruction, does not improve reliability. This approach also follows the NERC philosophy that standards should focus on results, not on methods. The results that the pro forma standard focuses on are clear communication of method, opportunity for influence, and data sharing; the standard, however, does not focus on the method for achieving them. In addition, while reducing the number of requirements, the pro forma standard actually addresses an existing reliability gap: the calculation of TTC or TFC by a TOP that is needed either by its RC or in its own operation of the system is now brought within the standard. In the past it would not have been addressed if not part of an ATC or AFC calculation.

The pro forma standard maintains the current state of transparency in the calculation of TTC, TFC, TRM, CBM, ATC, and AFC values. Like the existing ones, this standard requires documentation and disclosure of practices. By removing the instructional portions of the standard, the revised standard should improve transparency; the calculation method can be discussed as a story from start to finish using specifics and terms from the provider's actual process and software, rather than entities translating them into the instructions of the prior standard. The pro forma standard maintains the current level of transparency and may improve the quality of communications by removing a rigid framework to which the current descriptions must conform.

Consistency with regard to ATC, AFC, TTC, TFC, CBM, TRM, is a topic with four considerations to address. The first consideration is that the existing standards have not necessarily resulted in three methods of calculation. The variety of methods all fit under one of the three umbrella standards (MOD-028, MOD-029, MOD-030), but there are still very distinct differences in methods. The mandatory standard, market needs, corporate mergers, and technological advances heavily influenced the consolidation that has occurred over the last 10 years, but the influence of the codification of three methods may have been limited. Eliminating the codification will not remove the other pressures to consolidate methods. The second consideration is that the existing umbrella standards, while written to encompass the best reliable practices at the time and anticipated in the future, did not represent a new method of calculation. Instead, they were more a documentation of existing methods. As such, in many cases if those umbrella standards are retired, their absence will not drive an entity to change its operating practices. Entities may revise their implementation documents to fit the method more naturally than the standard-driven format of the description; this only improves the transparency, not the consistency of application. The final point is that if an entity does adjust its method (rather than just the description) because of the umbrella standards going away, it is not necessarily detrimental to reliability or to the market. If an entity is adjusting its method, it is likely due to market pressures, improvements in calculation efficiency, or reliability enhancements, none of which are detrimental to market access or reliability. The ad hoc group also elaborated on the three umbrella methods within this technical paper with the intent that the formal standard drafting team will further revise those descriptions and publish them as white paper. This would help address consistency since it would give another common reference for entities to look at when developing and describing ATC or AFC methods.

The proposed retirement of MOD-028, MOD-029, and MOD-030 does reduce the amount of regulation or structure in how the calculations are performed. The ad hoc group is helping to address this through their inclusion of instructional material on the methods within this paper. The group notes that most entities will not significantly change their techniques due solely to the reduction in standards requirements.

Purpose and Placement of the Pro Forma Standard

The revised standard serves three purposes. The first is to ensure reliable calculation of TTC and TFC values when calculated. The second is to ensure transparency and communication with the TOP, the RC, and other registered entities that may have a reliability need to understand how TTC, TFC, TRM, CBM, ATC, and AFC are calculated. The third is the sharing of data with other TOPs and TSPs to support their calculations of these values.

Calculation of Total Transfer Capability and Total Flowgate Capability – Addressed in Requirement R1 of Pro Forma Standard

TTC and TFC can be calculated by a TOP or a TSP either to support the determination of ATC or AFC, to support the RC, to support system operations, or a combination of reasons. Regardless of the reason, the TTC and TFC values (if calculated) need to have a sound basis and be derived from the system limits (e.g., facility ratings, stability limits, voltage limits, pre- and post-contingency conditions, or an SOL). Because the calculation of TTC or TFC can affect a neighboring TOP, the entity's calculation must include constraints identified by a nearby TOP. This assures that the TTC or TFC value protects the reliability of the entire BPS, not just the calculating TOP's system. Just like the calculation of SOLs, IROLs, and facility ratings, it is not necessary to reliability to specify the exact method of reaching the end value—only that the end value protect the reliability of the BPS. Therefore, the calculation of TTC or TFC by a TSP or TOP must be done in manner that protects BPS reliability on all affected systems.

Calculation of Available Transfer Capability and Available Flowgate Capability - Addressed in Requirement R2 of Pro Forma Standard

The selling of service itself is not a function of system reliability; the operating condition of the grid that the TOP and RC inherit is influenced when the time period for which ATC or AFC was calculated moves into real time. To ensure they are planning the system as it is being used, the TP and PC may be interested in the TSP's calculation of ATC and AFC to assure that the calculations of ATC and AFC respect the reliability limits for which the TP and PC planned the system. The determination of ETC is considered an integral part of the ATC calculation and is not broken out like TRM and CBM are below. Understanding how a TSP calculates ATC or AFC is important to system reliability.

Calculation of Transmission Reliability Margin and Capacity Benefit Margin - Addressed in Requirements R3 & R4 of Pro Forma Standard

The values of TRM and CBM are components in the determination of ATC; therefore, like ATC, the Transmission Operator and others have a reliability need to understand how these values are derived (if used) and how they are applied to reach an ATC value. Because other existing standards and processes reference a CBMID and a TRMID, the ad hoc group retained these terms for describing CBM and TRM, even though those descriptions could have been included in the ATCID. In addition, the ad hoc group specified that if an entity does not use CBM or TRM, it should still maintain an implementation document that states as much. Since many entities that did not maintain CBM and TRM already maintain an implementation document that said so (to facilitate compliance with NERC standards and other obligations), the ad hoc group did not believe this was a significant administrative burden. Therefore, understanding how a TSP or TOP calculates CBM and TRM is important to system reliability.

Sharing Data - Addressed in Requirements R5 & R6 of Pro Forma Standard

TSPs are often required to calculate ATC or AFC values due to other obligations, and both TSPs and TOPs may be required to calculate a TTC or TFC value. To meet this responsibility, the pro forma standard would also need to maintain the data-sharing requirement found in the current standard. This data-sharing requirement should maintain the same caveats that the existing standard does regarding only having to share data that the entities own and use in their calculations, as well as not having to change the data's format. A caveat should be added that this data sharing may be subject to a confidentially and security agreement between the entities. Therefore, it is important to reliability that TOPs and TSPs be obligated to share their data with other TOPs and TSPs for the calculation of TTC, TFC, TRM, CBM, ATC, and AFC values.

Jurisdictional vs. Non-jurisdictional Discussion

The ad-hoc group acknowledges that reliability standards issued under Section 215 of the Federal Power Act (FPA) are applicable to all owners, operators and users of the BPS in North America, however, FERC jurisdiction over market issues does not extend to all municipalities and electric cooperatives, which are otherwise subject to FPA Section 215. The pro forma standard covers reliability-related issues for the MOD A standards and applies to all entities subject to Section 215 of the FPA. Issues related to market standards, including which entities are subject to those standards, are beyond of the scope of NERC Reliability Standards.

Feedback from NERC Compliance

The ad hoc group received feedback from NERC Compliance on the use of the phrase "keep current and implement" within Requirements R2, R3, and R4 of the pro forma standard. The language within those Requirements is for a TSP or TOP to "prepare, keep current, and implement an ATC, CBM, or TRM (respectively for the Requirements) Implementation Document." Specifically, there was a comment as to "…recommends that the MOD A informal ad hoc group either consider making the requirement time-bound (such as every 12-months) or requiring the registered entity to document in their processes or procedures the frequency of review (with a not to exceed). Further, the pro forma standard should describe what constitutes implementation."

As an example for an entity to prepare, keep current, and implement an ATCID:

1. Prepare: If an entity calculates ATC or AFC values then that entity must have an ATCID. Almost all entities already have one, and this component of the phrase would only be focused on a brand new registered TOP or TSP.
2. Keep current: This component ensures that the entity's implementation document remains accurate to the entity's process. If an entity's ATCID states to use the "paper amount" of the reservation, but the method changes in using the expected usage of a reservation instead of the full paper amount, then the entity would be obligated to keep the implementation document current; preferably changing the implementation document before the entity changes the actual posted value. What this phrase does not entail is the periodic review to keep current with industry trends or changes on the system.
3. Implement: If an entity's ATCID says "A+B+C=ATC", then the entity shall demonstrate, through OATI WebTrans or another tool, that A, B, and C do indeed add up to ATC.

Outstanding FERC Directives

There are 20 outstanding FERC directives from Order 729. Each of the directives was discussed in detail during the informal development stage, and summaries of the discussions can be found below. Following the structure for identifying FERC directives, each directive was given an "S-Ref" identification number (i.e., S-Ref 10283). The ad hoc group extensively reviewed each of the directives with consideration of where the existing standards are today, where the group landed with the pro forma standard, and how the group addressed each directive.

The "Paragraph 81 initiative", which was issued by FERC in their March 15, 2012,[3] invited the ERO to identify possible requirements that could be removed from the NERC Reliability Standards that has little to no effect on reliability. The ad hoc group has taken the information from the NOPR into consideration when discussing the directives related to the MOD A initiative.

On June 20, 2013, FERC issued a Notice of Proposed Rulemaking (NOPR)[4] identifying 41 possible directives that may be withdrawn based on (1) whether the reliability concern underlying each outstanding directive has been addressed in some manner, thus rendering the directive stale; (2) whether the outstanding directive provides general guidance for standards development rather than a specific directive; and (3) whether the outstanding directive is redundant with another directive. Of the 41 possible directives, seven have been associated with the MOD A informal efforts. In that NOPR, FERC also proposed to retire 34 requirements within 19 reliability standards that either: (1) provide little protection for BPS reliability or (2) are redundant with other aspects of the reliability standards.

S-Ref 10204

129. If the Commission determines upon its own review of the data, or upon review of a complaint, that it should investigate the implementation of the available transfer capability methodologies, the Commission will need access to historical data. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to modify the Reliability Standards so as to increase the document retention requirements to a term of five years, in order to be consistent with the enforcement provisions established in Order No. 670**.

Consideration of Directive

Registered entities are required to keep data used in the ATC calculations due to the directives contained within FERC Order 670.[5] However, having to reproduce detailed data on a regular basis going back multiple years purely as a compliance exercise creates an unreasonable burden with no reliability benefit. The group modified the evidence retention requirements within the pro forma standard to five years for implementation documents and methods but applied a shorter data retention period for calculations. The group modified the evidence requirements within the pro forma standard to a graduated time frame for the calculations of hourly, daily, and monthly values based on MOD-028, MOD-029, and MOD-030 requirements. This is because there is no reliability benefit of having detailed supporting data of the calculations and that retention of the evidence would serve as an administrative burden.

S-Ref 10206

151. Nevertheless, the Commission believes that the lists of required recipients of the implementation documents may be overly prescriptive and could exclude some registered entities with a reliability need to review such information. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification to the Reliability Standards pursuant to the ERO's Reliability Standards development process to require disclosure of the various implementation documents to any registered entity who demonstrates to the ERO a reliability need for such information**.

Consideration of Directive

The MOD A informal ad hoc group noted that registered entities that have a reliability need for such information should be able to obtain information from a request for clarification on various implementation documents. Therefore, the group

[3] http://www.nerc.com/files/OrderConditionallyAcceptingNewEnfocementMechFiling_031512.pdf
[4] http://www.ferc.gov/whats-new/comm-meet/2013/062013/E-7.pdf
[5] http://www.ferc.gov/whats-new/comm-meet/011906/M-1.pdf

included in Requirement R5 of the pro forma standard the obligation for a TOP or TSP to respond to a PC, RC, TOP, TP, TSP, or any other registered entity that demonstrates a reliability need for disclosure of the various implementation documents, subject to confidentiality, regulatory, and security requirements.

S-Ref 10207

160. In Order No. 890, the Commission also expressed concern regarding the treatment of reservations with the same point of receipt (generator), but multiple points of delivery (Load), in setting aside existing transmission capacity. The Commission found that such reservations should not be modeled in the existing transmission commitments calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at the point of receipt. The Commission required the development of Reliability Standards that lay out clear instructions on how these reservations should be accounted for by the transmission service provider. The proposed Reliability Standards achieve this by requiring transmission service providers to identify in their implementation documents how they have implemented MOD-028-1, MOD-029-1, or MOD-030-2, including the calculation of existing transmission commitments. Thus we will not direct the ERO to develop a modification to address over-generation, as suggested by Entegra. Nonetheless, in developing the modifications to the MOD Reliability Standards directed in this Final Rule, **the ERO should consider generator nameplate ratings and transmission line ratings including the comments raised by Entegra.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the comments from Entegra regarding generator nameplate ratings and transmission line ratings. As explained above, this directive relates to ETC, which is a component of ATC or AFC. The pro forma standard requires disclosure of how the calculation of ETC is done, which would include generator nameplate ratings and transmission line ratings where appropriate. However, placing specific usage requirements on the TSP would not improve the quality of communication between the TSP and the TOP (or others) and has little to no impact on reliability. Because the ad hoc group states this directive is not associated to a reliability-related requirement as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10208

162. In Order No. 890, the Commission directed public utilities, working through NERC, to modify MOD-010 through MOD-025 to incorporate a periodic review and modification of various data models. The Commission found that updating and benchmarking was essential to accurately simulate the performance of the transmission grid and to calculate comparable available transfer capability values. On rehearing, the Commission clarified that the models used by the transmission provider to calculate available transfer capability, and not actual available transfer capability values, must be benchmarked. Updating and benchmarking of models to actual events will ensure greater accuracy, which will benefit information provided to and used by adjacent transmission service providers who rely upon such information to plan their systems. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations**, the Commission directs the ERO to develop benchmarking and updating requirements to measure modeled available transfer and flowgate capabilities against actual values**. Such requirements should specify the frequency for benchmarking and updating the available transfer and flowgate capability values and should require transmission service providers to update their models after any incident that substantially alters system conditions, such as generation outages.

Consideration of Directive

The ad hoc group considered the directive to developed benchmarking and updating requirements to measure modeled ATC and AFC values against actual values. The group understands that the underlying assumption in the directive is for verification of the models against actual values for ATC and AFC. Since the actions that contribute to reliability are the transparency of the implementation in the calculations of ATC or AFC, the verification of the accuracy of the values is not reliability-related. Because the ad hoc group states this directive is not associated to a reliability-related requirement as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10209

173. **The Commission therefore directs the ERO, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to develop a modification to MOD-028-1 and MOD-029-1 to specify that base generation schedules used in the calculation of available transfer capability will reflect the modeling of all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run, and to address the effect on available transfer capability of designating and undesignating a network resource**.

Consideration of Directive

As explained above, this directive relates to the calculation of ATC specifying that base generation schedules used in the calculation will reflect the modeling of all designated network resources. Requirement R2 of the pro forma standard requires disclosure of the TSP's practice in calculating ATC and Requirement R5 requires the TSP to respond to questions regarding its practice. Between the ATCID and the Requirement to respond to written requests, a TSP's practices regarding base generation schedules and the effect of designating and undesignating a network resource will be disclosed to the TOP and others. The ad hoc group states there is no direct benefit to the reliability of the BPS in setting NERC Requirements on how generation and network resources are supposed to be handled since that would not enhance the quality of communication between the TSP and the TOP (or others). The ad hoc group therefore required disclosure of the TSP's practices only.

S-Ref 10211

179. We agree that, in order to be useful, hourly, daily and monthly available transfer capability and available flowgate capability values must be calculated and posted in advance of the relevant time period. Requirement R8 of MOD-001-1 and Requirement R10 of MOD-030-2 require that such posting will occur far enough in advance to meet this need. With respect to Entegra's request regarding more frequent updates for constrained facilities, **we direct the ERO to consider this suggestion through its Reliability Standards development process**.

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered Entegra's comments regarding more frequent updates for constrained facilities. Within a TOP's or TSP's documentation and in response to questions from another entity, the TOP or TSP will provide information regarding the frequency of calculation and the frequency of updates for constrained facilities. This communication with the TOP and others is not improved by the standard mandating the frequency of calculation or the frequency of updates for constrained facilities. The issue of more frequent updates for constrained facilities is an issue with commercial access to the constrained paths and has little to no impact to reliability. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10212

179. Further, we agree with Cottonwood regarding unscheduled or unanticipated events. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **we direct the ERO to develop modifications to MOD-001-1 and MOD-030-2 to clarify that material changes in system conditions will trigger an update whenever practical**. Finally, we clarify that these Reliability Standards shall not be used as a "safe harbor" to avoid other, more stringent reporting or update requirements.

Consideration of Directive

The ad hoc group considered the directive to clarify that material changes in system conditions will trigger an update whenever practical. The revised version of the pro forma standard narrows the NERC reliability requirements down to the core essence of disclosure of practices. In an entity's ATCID, the TSP will disclose the frequency with which they make changes to the system in response to events. Rapid updates due to material events are a commercial issue of giving the best information to the market; however, since ATC does not directly reflect upon BPS reliability, there is no reliability benefit to mandate the frequency with which material changes in system conditions trigger an update.

S-Ref 10214

184. As proposed, MOD-001-1 does not restrict a transmission service provider from double-counting data inputs or assumptions in the calculation of available transfer or flowgate capability. To the extent possible, available transfer or flowgate capability values should reflect actual system conditions. The double-counting of various data inputs and assumptions could cause an understatement of available transfer or flowgate capability values and, thus, poses a risk to the reliability of the Bulk-Power System. We note that, in the Commission's order accepting the associated NAESB business standards, issued concurrently with this Final Rule in Docket No. RM05-5-013, the Commission directs EPSA to address its concerns regarding the modeling of condition firm service through the NERC Reliability Standards development process. We reaffirm here that modeling of available transfer capability should consider the effects of conditional firm service, including the potential for double-counting. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop modifications to MOD-001-1 pursuant to the ERO's Reliability Standards development process to prevent the double-counting of data inputs and assumptions. In developing these modifications, the ERO should consider the effects of conditional firm service**.

Consideration of Directive

The ad hoc group considered the directive to prevent double-counting of data inputs and assumptions. The existing standards of MOD-028, MOD-029, and MOD-030 each do a thorough job to ensure there is no double counting. Each method for calculating ATC or AFC is equal to the ETC + TRM + CBM + Postbacks + counterflows. MOD-008 has language which states you cannot double count between CBM and TRM, which now leaves only ETC as a candidate for double counting. However, each standard has descriptive requirements that do not allow you to double count. Finally, Postback and counterflow methods are to be described in an entity's ATCID. Consistent with the approach of the ad hoc group in pro forma standard, the transparency and disclosure of a TSP's ATCID will not allow for double counting. With regards to network service, this is more of a concern of customers inappropriately reserving service to game the system, and this behavior would better be suited as a consideration for a market monitoring function under NAESB or another standards body and not appropriate within the NERC Reliability Standards. Therefore, not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10215

192. In its filing letter, NERC states that it requires applicable entities to calculate available transfer capability or available flowgate capability on a consistent schedule and for specific time frames. In keeping with the Commission's goals of consistency and transparency in the calculation of available transfer capability or available flowgate capability, the Commission finds that transmission service providers should use consistent modeling practices over different time frames. If a transmission service provider uses inconsistent modeling practices over different time frames that should be made explicit in its implementation document along with a justification for the inconsistent practices. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification to the Reliability Standard pursuant to its Reliability Standards development process requiring transmission service providers to include in their implementation documents any inconsistent modeling practices along with a justification for such inconsistencies.**

Consideration of Directive

The ad hoc group considered the directive of requiring TSPs to include in their implementation documents any inconsistent modeling practice along with a justification. Within their documentation and in response to questions, the TSP or TOP will provide information regarding their modeling and if the modeling practices are consistent throughout time. As identified in Requirement R5 of the pro forma standard, an entity can request a rationale if there is a change in a modeling practice across time frames. It does not impair another entity to use the information contained within the TSP's ATCID. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10216

200. With regard to Midwest ISO's concern, while the terms "assumptions" and "no more limiting" as used in Requirements R6 and R7 could benefit from further granularity, we find these Requirements to be sufficiently clear for purposes of compliance. Likewise, with regard to Entegra's concern, we agree that transmission service providers should use data and assumptions for their available transfer capability or available flowgate capability and total transfer capability or total flowgate capability calculations that are consistent with those used in the planning of operations and system expansion. Under Requirements R6 and R7, transmission service providers and transmission operators must not overstate assumptions that are used in planning of operations. We believe these requirements are sufficiently clear as written. Nonetheless, **we encourage the ERO to consider Midwest ISO's and Entegra's comments when developing other modifications to the MOD Reliability Standards pursuant to the ERO's Reliability Standards development procedure**.

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the directive that the terms "assumptions" and "no more limiting" could benefit from further granularity. The TOP is potentially responsible for the TTC, TFC, and TRM calculations and must clearly communicate how those calculations are done both in the methodology and in response to requests for clarification. The reliability need is communication of the method so that other parties can understand how the calculation is being performed. There is no reliability benefit in requiring the TOP to explain how its TTC or TFC uses consistent or less limiting assumptions than their operations planning. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process as there may be important commercial aspects to ensure that the TSP is not being overly conservative in their determination of ATC. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10217

220. We agree with NERC that a transmission service provider should consider any information provided in establishing an appropriate level of capacity benefit margin. Similarly, we agree with the Georgia Companies that all relevant information should be considered in establishing an appropriate level of capacity benefit margin, including information provided by customers. However, in determining the appropriate generation capacity import requirement as part of the sum of capacity benefit margin to be requested from the transmission service provider, it would not be appropriate for a load-serving entity or resource planner to rely exclusively on a reserve margin or adequacy requirement established by an entity that is not subject to this Standard. **Thus, we hereby adopt the NOPR proposal to direct the ERO to develop a modification to Requirements R3.1 and R.4.1 of MOD-004-1 to require load-serving entities and resource planners to determine generation capability import requirements by reference to one or more relevant studies (loss of load expectation, loss of load probability or deterministic risk analysis) <u>and</u> applicable reserve margin or resource adequacy requirements, as relevant**. Such a modification should ensure that a transmission service provider has adequate information to establish the appropriate level of capacity benefit margin.

Consideration of Directive

The ad hoc group considered the directive to require LSEs and RPs to determination generation capability import requirements by reference to one or more relevant studies. The method of calculating CBM is determined by the TSP in keeping with any FERC or other standards bodies' guidelines and must be described in the TSP's CBMID. Placing a requirement on LSEs and RPs to provide certain information to that CBM process does not improve the quality of communication between the TSP and the TOP (or others). Also, the applicability section of the pro forma standard does not apply to LSEs or RPs, as it is the TSPs responsibility to prepare, keep current, and implement its CBMID. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10218

222. We agree with the Midwest ISO that ISOs, RTOs, and other entities with a wide view of system reliability needs should be able to provide input into determining the total amount of capacity benefit margin required to preserve the reliability of the system. However, Requirements R1.3 and R7 already make clear that determinations of need for generation capability import requirement made by a load serving entity or resource planner are not final. Further, the third bullet of Requirements R5 and R6 explicitly lists reserve margin or resource adequacy requirements established by RTOs and ISOs among the factors to be considered in establishing capacity benefit margin values for available transfer capability paths or flowgates used in available transfer capability or available flowgate capability calculations. In fact, it is for this reason that we uphold the NOPR proposal. Therefore, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to modify MOD-004-1 to clarify the term "manage" in Requirement R1.3**. This modification should ensure that the Reliability Standard clarify how the transmission service provider will manage situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available.

Consideration of Directive

The ad hoc group considered the directive to clarify the term "manage" in MOD-004-1. The pro forma standard does not include the prescriptive components and therefore does not contain the term "manage." Therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify this term.

S-Ref 10219

231. The Commission understands sub-requirement R2.2 of MOD-028-1 to mean that, when calculating total transfer capability for available transfer capability paths, a transmission operator shall use a transmission model that includes relevant data from reliability coordination areas that are not adjacent. While we believe that the provision is reasonably clear, the Commission agrees that the term "and beyond" could be better explained. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification sub-requirement R2.2 pursuant to its Reliability Standards development process to clarify the phrase "adjacent and beyond Reliability Coordination areas**."

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph clarifies the Commission's understanding of the phrase "adjacent and beyond Reliability Coordination area." Since the Commission's understanding of the language is clearly expressed, and the matter has little impact on reliability, there is no reason to go forward with this directive.

The ad hoc group considered the directive to clarify the phrase "adjacent and beyond Reliability Coordination areas." The pro forma standard does not contain the phrase "adjacent and beyond Reliability Coordination areas." Therefore, provided the standard is approved by industry without the phrase, it will not be necessary for NERC to clarify this phrase.

S-Ref 10220

234. The Commission believes that, as written, the time frames established in Requirement R5 are just and reasonable because they balance the need to reliably operate the grid with the burden on transmission operators to recalculate total transfer capability even when total transfer capability does not often change. Nevertheless, the Commission agrees that a graduated time frame for reposting could be reasonable in some situations. Accordingly, **the ERO should consider this suggestion when making future modifications to the Reliability Standards**.

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the directive of a graduated time frame for reposting of TTC even when TTC does not often change. Under the new pro forma standard, the time frame within which a value is recalculated and reposted based on an outage would be addressed by the TOP and the TSP in their methodology. There is no reliability benefit in the pro forma standard dictating the time frame for an Area Interchange Methodology user to update their TTC based on an outage since it does not contribute to the quality of communication with the TOP and others. Because the ad hoc group states this directive is not reliability focused as noted above, the ad hoc group proposes that this directive may be considered by

NAESB or another standards body through its standards development process. Removing a requirement or not directly responding to a directive that has little to no impact to reliability is also consistent with the Commission's Paragraph 81 initiative.

S-Ref 10221

237. The Commission agrees that any distribution factor to be used should be clearly stated in the implementation document, and that to facilitate consistent and understandable results the distribution factors used in determining total transfer capability should be applied consistently. Accordingly, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, **the Commission directs the ERO to develop a modification to MOD-028-1 pursuant to its Reliability Standards development process to address these two concerns.**

Consideration of Directive

The ad hoc group considered the directive to clearly state any distribution factor used in the implementation document. The pro forma standard requires disclosure of the TOP's method of addressing TTC and the TSP's method of determining ATC, which will require disclosure of how distribution factors are used, if they are used. Another reliability purpose of the standard is to allow other TOPs to influence the calculation of TTC and TFC. To address this, the ad hoc group included requirement part 1.3 in the pro forma standard. This requirement part states that the TTC or TFC methodology for calculating TTC or TFC shall address reliability-related constraints requested to be included per Requirement R1 and identified by another TOP are used within a component of the TTC or TFC calculation. Furthermore, the TOP must use a distribution factor, whether it be OTDP or PTDF of 5% or less when determining if these constraints should be monitored.

S-Ref 10222

246. Puget Sound's request is reasonable, and insofar as calculating non-firm available transfer capability using counterschedules as opposed to counterflows achieves substantially equivalent results, using them will not be considered a violation. However, we do not have enough information to determine that the terms are generally interchangeable in all circumstances. **The ERO should consider Puget Sound's concerns on this issue when making future modifications to the Reliability Standards**.

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard.

The ad hoc group considered the directive to clarify if the terms counterschedule and counterflow could be generally interchangeable in all circumstance. This new pro forma standard requires disclosure of the TSP's method of calculating ATC and would include their handling of counterflows or counterschedules. The pro forma standard focuses on clear communication between the TSP and the TOP (and others) on how ATC is calculated, and as such the standard does not specify the specific components that would go into the ATC calculation including counterflows and counterschedules, thus avoiding confusion between the two terms.

S-Ref 10223

269. As noted above, the Commission approves the proposal to make these Reliability Standards effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. Although MOD-030-2 defines its effective date with reference to the effective date of MOD-030-1, the Commission finds that this direction is sufficiently clear in the context of the current proceeding. To the extent necessary, we clarify MOD-030-2 shall become effective on the first day of the first calendar quarter that is twelve months beyond the date that the Reliability Standards are approved by all applicable regulatory authorities. **The Commission also directs the ERO to make explicit such detail in any future version of this or any other Reliability Standard.**

Consideration of Directive

This directive may be withdrawn subject to the FERC NOPR issued June 20, 2013. In the NOPR, FERC reasoned that this paragraph is not a directive to change or modify a standard. The ERO has made explicit the effective date in the pro forma standard.

S-Ref 10226

304. The Commission believes that the definition of Postback is not fully determinative. NERC should be able to define this term without reference to the Business Practices, another defined term. Accordingly, **the Commission adopts its NOPR proposal and directs the ERO to develop a modification to the definition of Postback to eliminate the reference to Business Practices**. Although we are sensitive to Puget Sound's concern that the required Postback component may increase the recordkeeping burden on some entities, in other regions the component may be critical. We disagree that the term's existence assumes that once a reservation is confirmed on a particular point of reservation or point of receipt combination the impact of the confirmed reservation will always be present in the available transfer capability calculation. However, we would consider suggestions that would allow entities to comply with the requirements as efficiently as possible, such as a regional difference through the ERO's standards development procedure.

Consideration of Directive

The term Postback is not used in the pro forma standard; therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify the term by adding this definition to the NERC Glossary of Terms used in the NERC Reliability Standards.

S-Ref 10227

305. **The Commission also adopts its NOPR proposal to direct the ERO to develop a modification to the definition of Business Practices that would remove the reference to regional reliability organizations and replace it with the term Regional Entity. We also direct the ERO to develop a definition of the term Regional Entity to be included in the NERC Glossary.**

Consideration of Directive

The term Business Practices is not used in the pro forma standard; therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify the term by adding this definition to the NERC Glossary of Terms used in the NERC Reliability Standards. The ad hoc group also notes that developing a definition to the term Regional Entity in the NERC Glossary of Terms Used in Reliability Standards would be another initiative by the ERO and not in focus for the MOD A informal ad hoc group.

S-Ref 10229

306. We agree with SMUD and Salt River that the definition of "ATC Path" should not limit a transmission provider's flexibility to treat multiple parallel interconnections between balancing authorities as a single path, and that available transfer capability paths may comprise multiple, parallel interconnections between Balancing Authorities when such treatment is appropriate to maintain reliability. We also agree that the definition should not reference the Commission's regulations. The Commission's regulations are not applicable to all registered entities and are subject to change. **We therefore direct the ERO to develop a modification to the definition of "ATC Path" that does not reference the Commission's regulations.**

Consideration of Directive

The term ATC Path is not used in the pro forma standard; therefore, provided the standard is approved by industry without the term, it will not be necessary for NERC to clarify the term by adding this definition to the NERC Glossary of Terms used in the NERC Reliability Standards.

Conclusion

The informal development for the MOD A initiative provided key discussions with regard to the reliability impacts of the existing MOD A NERC Reliability Standards. There were issues identified early in the process that were able to be discussed at varying lengths to come to the conclusion where the ad hoc group landed in consolidating the existing six standards into one pro forma standard. The pro forma standard covers the reliability-related impact of ATC and AFC calculations. The approach is intended to maintain NERC’s focus on developing and retaining requirements that support the reliable operation of the BPS.

This white paper serves as further information for the work the informal ad hoc group conducting in considering the outstanding directives from FERC Order 729, along with the other components of the results-based standards, such as a risk-based and performance-based standard, along with incorporating the Paragraph 81 initiative.

Appendix A: Acronyms

This section contains the list of acronyms used throughout the white paper.

Table 1: Acronyms

Acronym	Spelled Out	Acronym	Spelled Out
AFC	Available Flowgate Capability	**OTDF**	Outage Transfer Distribution Factor
ATC	Available Transfer Capability	**PC**	Planning Coordinator
ATCID	Available Transfer Capability Implementation Document	**POD**	Point of Delivery
BPS	Bulk Power System	**POR**	Point of Receipt
CBM	Capacity Benefit Margin	**PTDF**	Power Transfer Distribution Factor
CBMID	Capacity Benefit Margin Implementation Document	**RC**	Reliability Coordinator
EEA	Energy Emergency Alert	**RP**	Resource Planner
ERO	Electric Reliability Organization	**RSP**	Rated System Path
ETC	Existing Transmission Commitments	**SAR**	Standards Authorization Request
FERC	Federal Energy Regulatory Commission	**SC**	Standards Committee
FPA	Federal Power Act	**SOL**	System Operating Limit
GCIR	Generation Capability Import Requirement	**SME**	Subject Matter Expert
IROL	Interconnection Reliability Operating Limit	**STE**	Short-Term Emergency
ITC	Incremental Transfer Capability	**TFC**	Total Flowgate Capability
LSE	Load-Serving Entity	**TLR**	Transmission Loading Relief
LTE	Long-Term Emergency	**TO**	Transmission Owner
MW	Megawatt	**TOP**	Transmission Operator
NAESB	North American Energy Standards Board	**TP**	Transmission Planner
NERC	North American Electric Reliability Corporation	**TRM**	Transmission Reliability Margin
NOPR	Notice of Proposed Rulemaking	**TRMID**	Transmission Reliability Margin Implementation Document
OASIS	Open Access Same-Time Information System	**TSP**	Transmission Service Provider
		TTC	Total Transfer Capability

Appendix B: Entity Participants

The below entities represent a non-exhaustive list of entities that had personnel that participated in the MOD-A informal development effort in some manner, which may include one of the following: direct participation on the ad-hoc group, inclusion on the wider distribution (the "plus" list), attendance at workshops or other technical discussions, participation in a webinar or teleconference, or by providing feedback to the group through a variety of methods (e.g., email, phone calls, etc.). Additionally, though not listed here, announcements were distributed to wider NERC distribution lists to provide the opportunity for entities that were not actively participating to join the effort.

Table 2: Entity Participation in MOD A Informal Development

AECI	Dynegy	MEAG Power	PSEG	WAPA
ALCOA	ERCOT	MidAmerican	Puget Sound	WECC RC
Ameren	FPL	Minnkota Power	REMC	Wisconsin Public Service
APS	GCPUD	MISO	Santee Cooper	Xcel Energy
APSC	GRE Energy	National Grid	SaskPower	
ATC	GRU	NIPSCO	SCANA	
BC Hydro	GTC	Northwestern Energy	SCE	**Regional Entities**
Beaches Energy	Hydro Quebec	NSTAR	Seminole Electric	FRCC
BPA	HydroOne Networks	NV Energy	SMUD	MRO
CAISO	Idaho Power	OGE	SNEW	NPCC
CB Power Coop	IMPA	OMPA	Southern Company	RFC
Centerpoint Energy	ISO-NE	Oncor	SPP RC	SERC
City of Tallahassee	ITC Transmission	OPPD	SRP	SPP
ConEd	JEA	OUC	Sunflower Electric	TRE
Constellation Energy	KCPL	PacifiCorp	TANC	WECC
CPP	KUA	PGE	TECO	
CSU	LADWP	PJM	TEP	
Dominion	LCEC	PNM	TID	
Duke Energy	Lincoln Electric System	Portland General Electric	Tristate G&T	
Duquesne Light	MAPP	Progress Energy	TVA	

Table 3: Presentations and Events

Western Interconnection Compliance Forum	NERC Operating Committee
NATF	NERC News
wesTTrans	NERC Standards Committee
MISO Available Flowgate Capability Working Group	SPP Compliance Workshop
NERC Planning Committee	NERC Standards and Compliance Workshop
FRCC Transmission Working Group	Florida Transfer Capability Determination Group