Transmission Capability Margins and Their Use in ATC Determination

White Paper

Prepared by the North American Electric Reliability Council
Available Transfer Capability Working Group

June 17, 1999

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Background

In June of 1996, the North American Electric Reliability Council (NERC) approved a document entitled "*Available Transfer Capability Definitions and Determination*" as a framework for determining Available Transfer Capability (ATC) to satisfy both Federal Energy Regulatory Commission (FERC) requirements and industry needs. When approving the document, NERC recognized that it provides only an initial framework and may require expansion and modification as the industry gains experience. In defining the components that make up ATC, a number of new terms were introduced. Among these terms were two transmission margins to recognize uncertainty inherent in the interconnected power system. These two margins are known as the Transmission Reliability Margin (TRM) and the Capacity Benefit Margin (CBM). There is currently a large disparity in the magnitude of the margins applied by transmission providers across the Interconnections. Because of this disparity, especially in the quantification of CBM, the Available Transfer Capability Working Group (ATCWG) sponsored a symposium in January 1998. This symposium was designed to provide a forum to explore the different margin determination methodologies, and to encourage a convergence of the methodologies within and among the Regions. The purpose of this paper is to better define the margins and to foster a consistent approach for their determination and application.

Although both TRM and CBM are defined in the *Available Transfer Capability Definitions and Determination* document, the NERC Engineering and Operating Committees (EC/OC) (now referred to as the Adequacy and Security Committees (AC/SC), respectively) determined that the calculation and application of these margins requires further clarification beyond what is included in the ATC document. To this end, the EC/OC charged the ATCWG with the task of preparing a report to add needed detail to TRM and CBM methodologies. This document is in response to that request. Within this document, the reader will find definitions for both TRM and CBM that differ from the original definitions found in the NERC ATC document. It is the position of the ATCWG that these new definitions and descriptions should replace those in the 1996 document, in order to achieve a common understanding and approach for the need and quantification of these margins.

This paper has been written with the assumption that the reader is familiar with the NERC ATC document and that the legitimacy of the transmission margins has been established. Therefore, this paper is not intended as a justification of the need for transmission margins, but is rather a clarification and redefinition of how these margins are to be determined, allocated, and applied.

Purpose

This paper and the recommendations herein will be presented to the NERC AC for its consideration. If approved, this paper will serve as the foundation of NERC Planning Standards related to CBM and TRM and will be incorporated as an appendix to the 1996 ATC document. The intention of this effort is to reach consensus on the determination and quantification of TRM and CBM. At the very least, the Regions are encouraged to promote a common TRM and CBM determination methodology. An earlier version of this document was published on the NERC web site in January 1999 for public comment.

TRANSMISSION RELIABILITY MARGIN

Definition

Transmission Reliability Margin (TRM) is to be defined as:

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

Generally, the uncertainties associated with the operation of the interconnected electric system increase as the time horizon increases. These uncertainties can be attributed to weather conditions, forced and scheduled transmission outages, and generation unavailability. In the longer term, the health of the economy and the economics of generation will greatly influence the level and location of demand and electric resources. Because of these conditions, the uncertainties or “inaccuracy” of the TTC and ATC values also increase with time. The further into the future that TTC/ATC values are projected, the greater the uncertainty. For instance, future customer demands and generation dispatches are often quite uncertain, which greatly impacts the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Similarly, future electric power transactions are inherently uncertain and can have significant impacts on transmission system loadings. Compounding this problem is the difficulty that transmission systems not contractually associated with a particular transaction can experience in trying to quantify its impact on their respective systems. Therefore, the amount of TRM required is time dependent, generally with a larger amount necessary for longer time horizons than for near-term time periods.

Components of TRM

Transmission providers must consider the ATC margin components described in this section in their TRM calculations. Transmission providers may set all or some of the component values to zero. However, documentation that supports the quantification of TRM (including zero TRM values) is necessary. Transmission providers are advised to use caution in developing estimates of each component and subsequently combining all components together, as such an approach may result in TRM values that are unnecessarily large.

While the components that comprise TRM may be easily identifiable, the calculated values of these components may change depending upon experience and forecasts of system conditions. Transmission providers must address the TRM components for applicability to their systems. The methodology used to derive TRM and its components must be documented and consistent with published planning criteria, and must not account for uncertainties already accounted for elsewhere in the ATC determination. A TRM is considered consistent with published planning criteria if the same components that comprise it are also addressed in the planning criteria. The methodology used to determine and apply TRM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.

The components of TRM have the following unifying characteristics:

- The beneficiary of this margin is the “larger community” with no single, identifiable group of users as the beneficiary. The benefits of TRM extend over a large geographical area and over multiple transmission providers.

- They are the result of uncertainties that cannot reasonably be mitigated unilaterally by a single transmission provider or Regional entity.

Components that are to be considered in the determination of TRM:

- **Aggregate Load Forecast Error** C The load forecast is subject to error, as is any forecast. The inability to precisely predict a future load level and the subsequent loadings experienced on transmission system elements requires a reasonable quantity of transmission capacity to remain “uncommitted.” This “uncommitted” transmission resource, when actually needed in real time, benefits the entire community by helping to ensure that the reliability of the entire Interconnection is maintained.

- **Load Distribution Error** C Similar to an “error” in the aggregate load forecast, the distribution of the load will also vary the loading of system facilities. Maintenance of a reasonable quantity of “uncommitted” transmission capacity will help to ensure that the reliability of the entire Interconnection is maintained.

- **Variation in facility loadings due to the balancing of load and generation within a control area** C System load is a dynamic quantity. Generation increases and decreases in response to these load variations. A reasonable margin to account for this variation will help to ensure that the reliability of the entire Interconnection is maintained.

- **Forecast uncertainty in system topology** C Reasonable allowance for the impact of the myriad outages that may occur day-to-day also benefits the entire community. Most TTC calculations performed for the planning horizon are based upon the most critical single contingency and do not account for the base system condition including some level of facility outages.

- **Allowances for parallel path “loop flow” impacts** C Each network element is subject to parallel path flows. These parallel path flows are the result of transmission service transactions that are not explicitly scheduled on the transmission system of a particular transmission provider. Since these flows are not scheduled on their system, a transmission provider may not be aware of or able to explicitly account for the impact of other parties’ transactions on his own system. Therefore, maintenance of a reasonable quantity of “uncommitted” transmission capacity will help to ensure that the reliability of the entire

Interconnection is maintained. Note that proper coordination of basic system data between transmission providers should minimize the magnitude of this component.

- **Allowances for simultaneous path interactions C** Transmission paths may interact and not be capable of operation at each path's full transfer capability. The secure operation under such situations can be described by a nomogram. Nomograms may also be used to indicate the variability in capability of transmission paths as dictated by temperature, load level, available reactive support, and other factors. TRM may be used to account for the difference between the firm capability of a transmission path and the path's maximum capability.

- **Variations in generation dispatch C** The generation dispatch will vary for reasons such as the number of units having load following capability, generation availability, generation conditions within the generating plant, and economics. Maintenance of a margin helps account for the impacts of these variations upon the transmission system.

- **ShortBterm Operator Response/Operating Reserves C** Following a contingency, system operators take immediate actions, either individually or in concert with other operators, to maintain the reliability of the transmission system. Transmission capacity must remain available to allow for operator flexibility immediately following such a contingency. To maintain reliability, agreements between control areas exist to implement a quick and coordinated response following a transmission or generation contingency. Operating reserve programs (at least in part) are designed to provide transmission operators with procedures needed to maintain reliability. Therefore the transmission capacity needed to access operating reserves or to implement operating reserve sharing agreements for the period immediately following the contingency before the market can respond (currently up to 59 minutes following the contingency) is a TRM component. Any portion of a reserve sharing program that extends into the market reaction time (currently beyond 59 minutes following the contingency), should be included in CBM.

  Operating reserves are additional capacity either from generators that are on-line (loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur), or from generators that can be used to respond to a contingency within a short period of time (usually ten minutes). The existence of interconnections allows for the sharing of operating reserves between Control Areas, which reduces the amount of operating reserves each Control Area must carry on its own. The loss of a generating unit cascading into multiple system disturbances or load curtailments can be avoided by having adequate operating reserves. Operating reserve sharing programs have been implemented by a number of areas to provide reliability and economic benefits to the members of the group. As long as membership in these reserve-sharing groups remains open, they also provide benefit to the entire interconnected system. Operating reserves are provided for a limited time period, typically less than one hour. The consideration of operating reserves as a TRM component (unless explicitly modeled in TTC, as described later) recognizes that current procedures and technology limit the ability of the marketplace to replace a sudden loss of generation in real time. A quick replacement of an unexpected loss from a generation resource is necessary to maintain operating reliability performance levels. In fact, NERC's Interconnected Operations Services Implementation Task Force (IOSITF) has recommended that operating reserve sharing programs be designated as community Interconnected Operations Services that benefit the entire network. Therefore, although operating reserve is a generation quantity, operating reserves and operating reserve sharing agreements up to the time the market can respond (59 minutes or less) benefits the entire interconnection and must be considered a component of TRM.

There are two prevalent methods for determining the operating reserves component of TRM. 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 system.

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 the interface 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 interface.

TRM Application Methodologies

It is not the purpose of this paper to describe the detailed process of the calculation methodologies by which TRM is determined, but rather to delineate the thought process to derive the TRM quantity. Since TRM is a margin of transmission transfer capability withheld from firm and/or nonfirm transmission commitments for the benefit of the entire community, it is not necessarily a uni-directional quantity. There are two prevalent approaches to account for uncertainty as a TRM value, although there can be variations within these approaches. Typically, TRM is either calculated via a simple facility rating reduction (in percent of ratings) or a transfer capability quantity applied (in MW) at specific interfaces.

- **TRM applied by rating reduction —** For systems in which the distribution of uncertainty among all of its facilities is relatively uniform, a TRM applied to all the transmission provider’s system facilities may be appropriate. In this case, the TRM is applied against the facility ratings themselves and is measured as a percentage reduction of facility ratings. The rating reduction is typically 2–5% and may increase over an extended time horizon.

  This determination is typically accomplished by a two-step method:

  1. The TTC and ATC values are determined using the full “customary” (normal or emergency ratings as appropriate) ratings (i.e., assume that TRM is zero).

  2. Determine the ATC using facility ratings that are reduced from the “customary” ratings. The TRM (in terms of MW of transfer capability) is simply the algebraic

difference between the ATC values determined using the "customary" ratings and the ATC values determined using reduced ratings.

- **TRM applied by interface C** In systems where uncertain contributions can be associated with specific interfaces or flowgates, a TRM applied to specific critical interfaces or flowgates may be appropriate. Systems that apply TRM in this manner typically would be able to quantify the uncertainty associated with TRM components through the use of historical transmission loading analysis. In this case, the TRM is applied against a particular facility or set of facilities and is measured as a megawatt reduction in transfer capability. The TRM applied in this manner is relatively constant but may change based on the actual experience.

Although the general methods to apply TRM differ in application and approach, they both serve to quantify a reasonable amount of transfer capability margin to provide the operating flexibility to ensure reliable system operation as system conditions change. However, the applications of TRM are related in that the amount of TRM is a factor of the limiting facility's response for the particular transfer.

TRM should not be applied to paths limited by contract-based interconnection ratings or other contractual reasons (i.e., the path is "scheduling limited") since the capability of such a path is not subject to the uncertainties for which TRM is intended. The only exception is when a transmission provider incorporates a non zero operating reserve sharing component into TRM, and then must subtract this amount from the contractual capability of the facility/ties in question.

TRM may be sold on a nonfirm basis to the extent that the transmission provider feels it can do so without degrading system security.

Capacity Benefit Margin

Definition

Capacity Benefit Margin (CBM) is to be defined as:

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

Unlike TRM, the direct beneficiaries of CBM can be identified. These beneficiaries are the LSEs that are network customers (including native load) of a host transmission provider. The benefit that LSEs receive from CBM is the sharing of installed capacity reserves elsewhere in the

Interconnection, which translates into a reduced need for installed generating capacity and ultimately, lower rates for their customers.

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

Generally, CBM is not a "real-time" margin that "exists" in the current hour, but is a margin that extends from one hour into the future. The amount of CBM to be applied is in the form of a continuum in which the CBM is at a maximum amount in the longer term and a minimum level beginning with the next hour. This assumes that the uncertainty associated with generation availability decreases as the time horizon is reduced. In the current hour, generation capacity benefits in the form of operating reserves are considered part of the TRM. Operating reserves are provided for a limited time period, typically less than one hour. The recognition that operating reserves are a transmission reliability component acknowledges that current procedures and technology limit the ability of the marketplace to replace a sudden loss of generation in real time. A quick replacement of an unexpected loss of a generation resource is necessary to maintain operating reliability performance levels. Since quick replacement of lost resources benefits the entire Interconnection, operating reserves (for the time period between the contingency event and operator action to replace this power) provide reliability benefits beyond the specific LSE being served from that resource and is not considered part of CBM. Transmission capacity needed to accommodate generation reserves consistent with generation reliability criteria that are above the required operating reserve level would be included in CBM.

Generation reserve sharing programs extending beyond 59 minutes are used to meet generation reliability criteria. The NERC IOSITF has recommended that replacement power following a generator contingency that extends beyond a reasonable operator response time (typically one hour or less) be designated as an Interconnected Operations Service that benefits specific LSEs and not the entire community thersfore, generation reserve sharing uses that extend beyond 59 minutes are ***not*** to be included in TRM and are more appropriately accounted for in CBM.

Unlike TRM, CBM benefits an identifiable set of transmission system users: the LSEs. As such, CBM is only to be preserved as an import quantity (a uni-directional quantity) on the system of the host transmission provider. In determining the amount of CBM to apply, the requirements of all customers entitled to its use must be taken into consideration. Transmission providers have the responsibility to determine CBM, but must do so with the input of all LSEs entitled to a portion of the CBM.

Transmission providers must consider their obligations, if any, to supply CBM to interruptible customers or to customers that have contractual provisions to arrange their purchases of generation resources during a capacity deficiency (sometimes referred to as “buy-through” customers). It may be prudent to include buy-through customers in determining the generation reserve requirements of a host transmission provider, since they are retail native load customers and have the option to purchase from outside the system at their discretion. Interruptible customers should generally not be considered, since these customers do not have an option to continue their consumption when ordered to curtail by control area operators. It is prudent to include the same portion of the interruptible load in the CBM determination that is expected to be available during a CBM event, recognizing that not all interruptible loads will be at maximum levels when a CBM event occurs.

CBM Calculation and Allocation

The methodology used to derive CBM must be documented and consistent with published planning criteria. A CBM is considered consistent with published planning criteria if the same components that comprise the CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained. It is recognized that ATC determinations are often time constrained and thus will not permit the use of the same mechanics employed in the more rigorous planning process.

The Generation Reserve Requirement can be determined via either deterministic or probabilistic methods.

- **Probabilistic Methodology** — Probabilistic calculation methods, such as loss of load probability, have inputs such as unit forced outages, maintenance outages, minimum downtimes, load forecasts, etc. A typical benchmark is a generation reserve level to achieve a probabilistic loss of load expectation of 0.1 day per year.

- **Deterministic Methodology** — Deterministic methods typically are centered on maintaining a specified reserve or capacity margin, or may be based upon surviving the loss of the largest generating unit. Typical benchmarks for the determination methodology would be a multiple of the largest generation unit within the transmission provider’s system.

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

The determination of CBM for an LSE is a three-step process:

1) The amount of additional external generating capacity necessary to achieve a target reliability level (e.g., 0.1 day/year loss of load expectation) must be determined.

2) The total amount of transmission transfer capability necessary to import the external generating reserve requirement must be determined from the amount of required external generating capacity (less the TRM component for operating reserves).

3) This total amount of transmission transfer capability must be allocated to the specific transmission system interfaces or paths over which the imported power may flow.

These three steps can be accomplished either sequentially or simultaneously. Sequential determination often relies on deterministic rules. For example, the needed external generating capacity might be set at the capacity of the largest internal plant, the total CBM might be set at two times that amount, and the allocation among three interfaces might be set as 60/20/20%, based upon historical experience. Simultaneous determination can be accomplished with a probabilistic model, which includes both generation and transmission representation.

Regardless of the process used, the transmission provider must ensure that:

a) The method used to arrive at the amount of external generation needed is consistent with applicable reliability criteria.

b) If the total transmission capacity reserved as CBM on all interfaces exceeds the external generation reserve requirement (less the TRM component for operating reserves), it is reasonable and justified.

c) The allocation of the total CBM to individual interfaces, or source points, is consistent with available external generation resources, known transmission limitations, and historical transfer patterns during actual emergency generating capacity deficiency events.

The allocation of CBM to the host transmission provider interface(s) must be based solely on the generation reserve and projected availability of outside sources (the strength of the transmission interfaces needed to import the CBM requirement allocation) and the historical availability of outside resources. The preservation of CBM on the importing transmission provider’s system does not ensure the availability of transmission transfer capability on other systems, but relies on the diversity of generation and transmission resources that may be available on the Interconnection during a generation emergency. Therefore, the availability of third-party transmission transfer capability must be a consideration in the allocation of CBM.

CBM may be allocated to each Interconnection interface and subtracted from the calculated TTC. In doing so, the actual flow impacts of CBM reservations may not be taken into account. In some cases, it may be appropriate for the transmission provider to allocate CBM to each interface in such a manner that the sum of the allocations to all the interfaces exceeds the generation requirement used to determine the CBM. This is to recognize the low probability of all resources upon which dependency is projected being available simultaneously.

CBM may also be allocated to a transmission system by modeling the generation reserve requirements as base transfers and examining, via power flow analysis, the impacts of the modeled generation reserve requirements upon the TTC of the path being studied. This method accounts for the predicted flow impacts of the CBM preservation.

If contractual rights on an interface or path form the limit for the path for which source points for a CBM requirement are being modeled, it is not appropriate to model an import in excess of the contractual "scheduling" limit. The net schedule on a contractually limited interface is currently limited to the ownership rights of the seller and is not based upon actual flow. Modeling a base import amount in excess of the contract path limit will not reflect the appropriate scheduling limit on the interface in this case. The use of this method on a contractually limited interface may result in an inability of the LSE to schedule the required CBM amount on that specific path, as illustrated in the following example:

> ***Example***: An interface between Area A and Area B is limited by contract to 500 MW in the direction from A to B, and there is no network limit less than 500 MW. In this case, the maximum TTC is limited to 500 MW from A to B. At no time should more than 500 MW be scheduled across the interface from A to B (note: systems offering congestion management options are permitted to sell, but not schedule, nonfirm above the contractual limit). If the CBM requirement from A to B is 200 MW, this must be subtracted directly from the 500 MW TTC. If the actual flow impacts of the 200 MW are less than the requirement (assume it is 125 MW) and are all that is removed from ATC, the transmission provider cannot schedule the entire 200 MW CBM requirement if the interface becomes fully subscribed. The 500, less only the 125, would leave 375 available for firm service. If that becomes reserved, the transmission provider could never schedule the full 200 MW of CBM requirement on that contract path. The LSE would need to secure an alternate contract path for the remaining 75 MW.

CBM is not to be allocated directly to through paths (also known as wheeling) unless one of the interfaces is limited contractually (for the reason above). If CBM is allocated using the base transfers method, the impacts of preserving CBM will be reflected on all paths and any appropriate limits on through paths as a result of CBM allocation on import paths will be accounted for in the TTC calculation.

Use of CBM

CBM may be sold on a nonfirm basis. As with any margin, the generation reserve requirement (and therefore the CBM) should be recalculated as conditions change. If a change (increase or decease) in CBM on a particular path is prudent due to current or projected conditions, the host transmission provider (and/or the LSE) may change the CBM on the path, provided that there is sufficient firm ATC on that path. If there is not sufficient firm ATC available, the host transmission provider (and/or the LSE) cannot unilaterally displace other existing firm uses of the interface. Regions should establish CBM re-determination schedules.

The use of CBM "in advance" of the near-term horizon must be fully explained by the LSE. CBM is only to be used for capacity deficiency emergency conditions. These conditions should not be driven purely by economic reasons, but rather must be based upon true emergency generation deficiencies. CBM should be invoked only after all other options available to the LSE (short of shedding firm load) have been exhausted or should be consistent with the requirements of any applicable reserve sharing group.

It is the position of the ATCWG that both the CBM methodology and values should be made available to customers either via the OASIS or some other publicly accessible site. All transmission users should have access to the CBM methodology of the Region and/or the individual transmission provider as well as the CBM values for all commercial paths.

ASSUMPTIONS RELATED TO THE DETERMINATION OF TRM/CBM

It is helpful in determining TRM and CBM to be cognizant of factors that must be considered in developing ATC, but are not deemed appropriate components of TRM and CBM.

1) At a minimum, all single transmission and generator contingencies shall be included in the determination of TTC, provided the contingencies are consistent with appropriate published NERC, Regional, subregional, power pool, and individual system reliability criteria.

2) Inertial response (or frequency bias) to generator contingencies is considered in TTC calculations.

3) All known generation and transmission outages are incorporated into ATC calculations for both firm and nonfirm transmission service.

4) Thermal ratings applied in the determination of TTC should be contingency-based (e.g., emergency) ratings.

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