Southeastern Electric Reliability Council (SERC)

Transmission Provider CBM/TRM Need & Methodology Statements

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Introduction

The Southeastern Electric Reliability Council (SERC) membership includes 39 member systems and 31 associate members. The Region, represented by the Council, is located in 13 states in the Southeastern United States and covers an area of approximately 464,000 square miles. SERC is divided geographically into four diverse subregions that are identified as Southern, Tennessee Valley Authority (TVA), the Virginia-Carolinas Area (VACAR), and Entergy.

Southern Control Area

CBM/TRM Need and Methodology Statements

November 9, 1998
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Description of the Southern Subregion of SERC

The Southern Subregion of SERC is comprised of the following members : Alabama Electric Cooperative (AEC), Crisp County Power Commission, Georgia Systems Operation Company (formerly Oglethorpe Power), Municipal Electric Authority of Georgia (MEAG), Southeastern Power Administration (SEPA), South Mississippi Electric Power Association (SMEPA), and the five operating companies of Southern Company (Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Savannah Electric and Power).

The Southern subregion members have numerous interconnections among themselves as well as several ties to other subregions and one region. The following interconnections from Southern subregion members to neighboring SERC subregions exist: Entergy (1- 500 kV tie, 2 – 230 kV ties, and three 115 kV ties); TVA (3 – 500 kV ties, 1 – 230 kV tie, 4 – 161 kV ties, and 1 – 115 kV tie); VACAR (1 – 500 kV tie, 4 - 230 kV ties, and 4 – 115 kV ties). The Southern Subregion is also tied to the FRCC through 2 – 500 kV ties, 4 – 230 kV ties, and 4 – 115 kV ties.

SOUTHERN COMPANIES' PROCEDURES
FOR RESERVING
CAPACITY BENEFIT MARGIN

ELIGIBILITY FOR CBM

CBM is available for load serving entities using the transmission system of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company (collectively "Southern Companies") to serve native load and network load customers. These entities include Southern Companies (and their agent, Southern Company Services, Inc.), existing network service customers (Alabama Electric Cooperative, Inc., Southeastern Power Administration, and the Tennessee Valley Authority) and new network service customers under the Open Access Transmission Tariff of Southern Companies.

RESERVATION OF CBM

Each load serving entity is responsible for reserving its own CBM requirements. To make such a reservation, the load serving entity should submit a request to Southern Companies' transmission function setting forth the following information: (i) the amount of CBM desired on each particular interface; (ii) a description of the methodology used to determine its CBM; and (iii) the basis for reserving CBM on the requested paths. Southern Companies' transmission function will attempt to accommodate requests for CBM to the extent that transmission capacity is currently available on a "first come-first served" basis. Southern Companies' transmission function does not intend to "police" CBM requests, but reserves the right to deny CBM requests that appear unreasonable or disproportionate given the amount of native/network load service being provided to that load serving entity by Southern Companies' transmission system.

USE OF CBM

CBM may be used during emergencies by those who reserve it to import power on a firm basis into the Southern Company control area to ensure the continued reliability of service to native/network load customers.

DEFINITION OF EMERGENCY

An emergency exists when the resources of an entity are projected to be insufficient to serve its native/network load customers.

PROCEDURES FOR USING RESERVED CBM DURING EMERGENCIES

The procedures to be followed in using reserved CBM are outlined below:

1. The load serving entity will make a reservation on OASIS for network transmission service (Type = Network; Class = Firm; Increment = Daily, Weekly, Monthly, Yearly) on a specific path on which it has reserved CBM.
2. The load serving entity will note in the comment section of the network service template that the reservation is for the use of CBM capacity on the path.
3. Southern Companies' transmission function will evaluate the transmission service request and provide the requested CBM transmission service on a firm basis if sufficient transmission capacity is available on the path.

AVAILABILITY OF RESERVED CBM CAPACITY TO OTHER CUSTOMERS

Transmission capacity reserved for CBM will be made available to all eligible transmission customers on a non-firm basis when CBM is not needed to maintain system reliability during periods of projected resource deficiencies.

Capacity Benefit Margin (CBM) for
Southern Companies' Native Load Customers

The Resource Planning Manager at Southern Company Services, Inc. (SCS) has previously requested that the following quantities of CBM be reserved on behalf of the native load customers of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company:

Interface	1999	2000	2001	2002 and beyond
Entergy	0	300	300	300
TVA	300	450	450	450
Duke	250	100	100	100
SCEG	0	100	100	100
Santee	200	100	100	100

Description of Methodology Used to Determine CBM

The assessment to determine the amount of CBM required to maintain system reliability for Southern Companies' native load customers was conducted by the Resource Planning area of the generation function.

Through a probabilistic analysis using a Monte Carlo reliability model, it was recently determined that the target system planning reserve margin would be adequate if 750 MW of total imports from tie lines are available during peak hours. The Monte Carlo method considers generating unit forced outages and derations based on historical time to failure and time to repair data and the diversity of generating unit forced outages in the region. Load forecast error probabilities, electrical load from extreme weather temperature probabilities, and the probabilities of dry weather and its impact on hydroelectric energy were inputs to the model. It is anticipated that this analysis will be conducted at least every three years, and may be performed more frequently if system conditions or assumptions change significantly.

Basis for Reserving CBM on Specific Paths

Total import capability from tie lines during peak hours is a function of both tie line limits and the availability of generating capacity on the other side of the tie line. While the Monte Carlo model assesses needed imports of generating capacity to maintain system reliability, it does not determine the particular interface over which such generating capacity might actually be available. Total CBM in excess of 750 MW is thus needed because it is unlikely that 750 MW of generation will be available on the other side of the specific tie lines to exactly match import needs. For this reason, somewhat more than 750 MW of CBM must be reserved to ensure that the required 750 MW could actually be imported during emergency conditions. In this way, the target reserve margin will be adequate and native load customers will not be faced with the additional cost of more generating capacity.

For 1999, the requested CBM reservations total less than what would be appropriate based on the planned reserves for that year. The understated CBM reservations reflect a practical assessment of the availability of generation on the other side of the tie lines and tie line capacity available for the current peak season. For 2000, 2001, and 2002 and beyond, the requested CBM reservations are sufficient under the current target reserve margin.

Procedures for Using CBM During Emergencies

When Southern Companies' resources are projected to be insufficient to serve the native load customers of the five operating companies, CBM may be called upon to import power on a firm basis into the Southern Company control area to ensure the continued reliability of service to those customers. Southern Wholesale Energy (the wholesale merchant function of SCS) will use CBM in accordance with the procedures set forth on Southern Companies' OASIS.

Southern Control Area
Need and Methodology Statement for Calculation of TRM

Need for TRM

The Southern Control Area Transmission Providers have identified a need for an amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure. This margin is also (at the same time) needed to provide commercially viable results (of transmission transfer capability) for all entities requesting transmission service from the transmission providers in the Southern Control Area. The Southern Control Area has only identified an internal system need for TRM for imports across the major interconnections with neighboring transmission systems. Southern recognizes that other transmission providers may apply a different methodology for determination of TRM for their own internal system needs and therefore does not calculate TRM for exports.

Use of TRM in ATC calculations

The use of TRM in the calculation of ATC (as defined in the NERC "Available Transfer Capability Definitions and Determination" document dated June 1996) is:

Firm ATC (Non-recallable)= TTC - TRM - CBM - Existing Transmission Commitments

Non-Firm ATC (Recallable) = TTC - Existing Transmission Commitments

Where: ATC = Available Transfer Capability
TTC = Total Transfer Capability
TRM = Transmission Reliability Margin
CBM = Capacity Benefit Margin

Availability of TRM to the Market

In the Southern Control Area, TRM can be sold on a non-firm basis to the market. There are no special conditions required for its usage as non-firm transmission service.

Components of TRM for the Southern Control Area

The four components of TRM for the SERC Region (as required by SERC's "Guidelines for Transmission Capability Margins" document) are:

1. **Variations in generation dispatch = 0 MW**
   Location and output of generation assumed in planning and pre-operational horizons may be vastly different from actual operating conditions. A margin may be necessary to account for generation sensitivity effects on Transmission Capability. While the Southern Control Area recognizes that variations in generation dispatch will have an effect on the calculation of total transfer capability, by using the most critical unit to an interface in the calculation of FCITC we account for this uncertainty

in the calculation of total transfer capability. Therefore, the TRM component of *"variations in generation dispatch"* is zero for both imports and exports.

2. **Allowances for parallel path "loop flow" impacts = 0 MW**
   While parallel path impacts occur, their unpredictable nature makes it difficult to quantify a specific TRM value for an individual interface. The typical characteristic of parallel path flows across the Southern Control Area is that one or more interfaces will have a reduction in its total transfer capability while another interface(s) will have an increase in its total transfer capability. Due to the unpredictable nature of parallel flows, the quantification of a component that accounts for parallel path flows is not considered at this time. Therefore, for the Southern Control area, the TRM component for the *"allowance for parallel path 'loop flow' impacts"* is zero for both imports and exports.

3. **Allowance for simultaneous path interactions = 0 MW**
   This component quantifies the interaction of transmission paths. Transmission paths may interact and not be capable of operation at each path's full transfer capability. TRM may be used to account for the difference between the firm capability of each interacting path and the maximum capability of each path (typically, through the use of nomograms). At this time the Southern Control Area does not use this method for determining TRM. Therefore, the TRM component for *"allowance for simultaneous path interactions"* is zero for both import and exports.

4. **Short Term Operator Response /System Response /Operating Reserves = 900 MW**
   Following a contingency, system operators take immediate actions, either individually or in concern 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. The need for a transfer margin to ensure the reliability of the transmission system across the Southern Control Area is determined for imports into the Southern Control Area for all major interfaces. Southern Control Area's TRM component for "Short Term Operator Response / System Response" is 900 MW for imports and zero for exports.

<u>The Magnitude of TRM</u>

The Southern Company grid maintains an "Operating Reserve" of 1800 MW based on 1-1/2 times the largest unit (1200 MW) in the Southern Control Area. Of the 1800 MW required on the Southern Company grid, at least 50% is required by NERC Operating Policy 1 - Generation Control and Performance - to be spinning and the remainder is required from the transmission interfaces until additional resources can be made available on-line. The total Transmission Reliability Margin (TRM) is set to equal the total non-spinning operating reserves (normally 900 MW). Since OPC, MEAG and Dalton as members of the Integrated Transmission System (ITS) share the existing interfaces with Southern Company grid, the TRM of 900 MW has been allocated to all interface owners.

<u>Allocation of TRM at Interfaces</u>

There are four major interfaces for Southern Company grid. They are: TVA, VACAR, Florida and Entergy. The ITS shares TVA, VACAR and Florida interfaces with Southern Company grid. Since Duke, Florida, TVA and Entergy each have 500 kV transmission lines interconnected to Southern Company grid, it was decided to allocate the total 900 MW of the Southern Control Area TRM among TVA, Duke, Florida and Entergy. TRM at other interfaces, such as SCE&G and SCPSA, will be zero MW.

Allocation Methodology

The methodology uses the inertial response of the interfaces to a loss of a generator in Southern Company grid. Analysis was made by removing one major unit of generating capacity greater than 500 MW from each plant site, one at a time, in order to assess inrush requirement at each interface. PTI's PSS/E Stability Model was used to examine the governor's response for all the generators in the Eastern Interconnection modeled 30 seconds after the loss of the major unit. Thirty seconds was selected to allow the generator governors to settle out at the new operating point.

The analysis was conducted using the 1996 SERC Stability DataBase. The following units in the Southern Control Area were removed one at a time and the response of each interface was recorded: Vogtle 2, Miller 4, Hatch 2, Gaston 5, Watson 5, Farley 2, Bowen 4, Wansley 2, Scherer 3, Gorgas 10, Barry 5 and Daniel 2. The largest MW response of each interface (for the outage of units under consideration) was selected for allocation towards TRM. Based on the study, the largest response for Duke, Florida, TVA and Entergy interfaces were 370.78,193.4, 295.31 and 285.92 MW, respectively. The TRM of each interface was normalized based on the total value of 900 MW.

For example:

The largest response for the Duke interface is 370.78 MW,
TRM for Duke interface based on 900 MW is
370.78 x (900/(370.78+193.40+295.31+285.92)) = 291.34 MW

After rounding off to the nearest integer, TRM for Entergy was adjusted so the total value of 900MW could be matched.

Obligations of TRM among ITS Members

The TRM at each interface is allocated to the ITS partners based on the current or future approved ITSA methodology for allocating the ITS interface.
For example:

MEAG's allocation in % of ITS interface is 8.83%,
MEAG's obligation of TRM for Duke interface is
291.34 x 8.83% = 25.64 MW

After rounding off to the nearest integer, TRM for the Southern Company grid was adjusted so the total value for the particular interface could be matched. All ITS members have approved the method and allocation factors for TRM.

Update Frequency of TRM for the Southern Control Area

The need and the methodology for calculating and allocating TRM will be reviewed annually by Southern Company and ITS members. Changes will be made as necessary to maintain the reliability needs of the Southern Control area. The TRM numbers could also be revised if significant changes are made to the SERC dynamic database.

Deviation of TRM from Regional Document for the Southern Control Area

The Southern Control Area does not allow for transmission providers within the control area to deviate from the Regional TRM methodology.

Results

The analyses indicate that approximately 75% of the lost generation is picked up by the interconnected utilities through the existing transmission interface. 75% of the largest generating unit in Southern Company grid (Vogtle) is 900 MW. This reinforces that using 900 MW for the total TRM is appropriate. The interface response for 1996 summer peak conditions is shown in the attached Table I. It shows the allocated TRM at each interface. It also shows the obligations assigned to Southern Company grid, OPC, MEAG and Dalton based on the allocated TRM at each interface. Table II is the interface response for 1996 valley conditions. The results are slightly different. However, similar trending of the responses can be seen in both analyses. It was decided that the TRM allocation would be based on the Summer Peak conditions.

		1996 SUMMER PEAK CONDITIONS			
		INTERFACE RESPONSE			
UNIT OUT	DUKE	FLORIDA	TVA	ENTERGY	TOTAL
VOGTLE 2	370.78	193.4	288.61	45.04	897.83
	41.30%	21.54%	32.15%	5.02%	100.00%
MILLER 4	113.55	113.4	288.91	9.94	525.8
	21.60%	21.57%	54.95%	1.89%	100.00%
HATCH 2	234.2	137.1	219.41	42.67	633.38
	36.98%	21.65%	34.64%	6.74%	100.00%
GASTON 5	167.01	136.8	295.31	35.01	634.13
	26.34%	21.57%	46.57%	5.52%	100.00%
WATSON 5	84.91	82.8	-48.71	253.754	372.754
	22.78%	22.21%	-13.07%	68.08%	100.00%
FARLEY 2	188.62	136.5	223.51	77.54	626.17
	30.12%	21.80%	35.69%	12.38%	100.00%
BOWEN 4	224.95	145.9	284.41	20.84	676.1
	33.27%	21.58%	42.07%	3.08%	100.00%
WANSLEY 2	230.94	144	262.61	28.19	665.74
	34.69%	21.63%	39.45%	4.23%	100.00%
SCHERER 3	240.95	140	238.81	28.95	648.71
	37.14%	21.58%	36.81%	4.46%	100.00%
GORGAS 10	90.99	83.8	198.61	16.95	390.35
	23.31%	21.47%	50.88%	4.34%	100.00%
BARRY 5	133.98	121.9	-0.08	285.92	541.72
	24.73%	22.50%	-0.01%	52.78%	100.00%
DANIEL 2	90.96	87.5	-44.25	260.275	394.485
	23.06%	22.18%	-11.22%	65.98%	100.00%
LARGEST MW	370.78	193.4	295.31	285.92	1145.41
ALLOC. OF 900MW	291.34	151.96	232.04	224.66	900.00
OBLIGATIONS					
Southern	191.12	102.58	191.43	224.66	709.78
OPC	71.09	34.65	28.77	0.00	134.51
MEAG	25.64	12.92	10.44	0.00	49.00
Dalton	3.50	1.82	1.39	0.00	6.71
Total	291.34	151.96	232.04	224.66	900.00

		1996 VALLEY CONDITIONS			
		INTERFACE RESPONSE			
UNIT OUT	DUKE	FLORIDA	TVA	ENTERGY	TOTAL
VOGTLE 2	388.7	178.7	286.12	48.71	902.23
	43.08%	19.81%	31.71%	5.40%	100.00%
MILLER 4	126.01	110.5	284.84	12.812	534.162
	23.59%	20.69%	53.32%	2.40%	100.00%
HATCH 2	254.05	125.6	227.38	46.16	653.19
	38.89%	19.23%	34.81%	7.07%	100.00%
WATSON 5	85.51	74	-61.25	253.26	351.52
	24.33%	21.05%	-17.42%	72.05%	100.00%
FARLEY 2	206.9	132.7	229.74	81.57	650.91
	31.79%	20.39%	35.30%	12.53%	100.00%
BOWEN 4	244.31	141.2	292.55	24.29	702.35
	34.78%	20.10%	41.65%	3.46%	100.00%
WANSLEY 2	158.48	87.9	170.47	19.73	436.58
	36.30%	20.13%	39.05%	4.52%	100.00%
SCHERER 3	186.49	96.1	175	23.1	480.69
	38.80%	19.99%	36.41%	4.81%	100.00%
BARRY 5	149.411	116.9	12.98	268.82	548.111
	27.26%	21.33%	2.37%	49.04%	100.00%
LARGEST MW	388.7	178.7	292.55	268.82	1128.77
ALLOC. OF 900MW	309.92	142.48	233.26	214.34	900.00
OBLIGATIONS					
Southern	203.31	96.18	192.44	214.34	706.26
OPC	75.62	32.49	28.92	0.00	137.03
MEAG	27.27	12.11	10.50	0.00	49.88
Dalton	3.72	1.71	1.40	0.00	6.83
Total	309.92	142.48	233.26	214.34	900.00

Georgia Transmission Company (GTC)

CBM/TRM Need and Methodology Statements

November 9, 1998

GTC's Transmission Reliability Margin (TRM)

Georgia Transmission Corporation (GTC) is allocated a portion of the total TRM in the Southern Company control area. Please see Southern's response for the methodology and values currently posted by GTC.

GTC's Capacity Benefit Margin (CBM)

Georgia Transmission Corporation's (GTC's) native load customers are currently relying on GTC's allocated firm import transfer capability through firm reservation commitments. Therefore, although GTC believes the use of CBM for future undesignated resources is consistent with FERC/NERC policies, GTC's current CBM values at all of GTC's interfaces is set to zero.

Municipal Electric Authority of Georgia (MEAG)

CBM/TRM Need and Methodology Statements

November 9, 1998
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MEAG's Transmission Reliability Margin (TRM)

Municipal Electric Authority of Georgia (MEAG) is allocated a portion of the total TRM in the Southern Company control area. Please see Southern's response for the methodology and values currently posted by MEAG.

Municipal Electric Authority of Georgia (MEAG Power) Capacity Benefit Margin (CBM)

MEAG Power's planned reserve margin of 15 % is only adequate from a reliability standpoint because significant tie lines are currently available. A production costing and reliability computer model called PROSYM, developed by Henwood Energy Services, Inc., was used to analyze the reliability of MEAG Power's system considering unplanned unit outages.

In the study of "Analysis of Available Transmission Capacity for the Municipal Electric Authority of Georgia, March 3, 2000," MEAG Power's staff has determined that the reliability criteria of one to two loss of load hours per year and 0.001% of load not served per year are acceptable planning parameters. MEAG Power does not meet these criteria without its current interface capability. In order to achieve this level of reliability, the capacity shortage must be remedied through planned and emergency purchases. Therefore, adequate amounts of import capability are required to be available for such purposes.

The required capacity to maintain MEAG Power's reliability through interface is identified as Capacity Benefit Margin (CBM). The CBM for MEAG Power is the summation of the purchased capacity and the emergency capacity required avoiding any load shedding. The purchase capacity required for reliability was determined by a simulation study adding firm capacity to the system at 95% availability rate until the reliability statistics were in the acceptable range as identified above. If import interface capability were no longer available, this capacity would have to be installed on MEAG Power's system or additional import capability would need to be purchased from another party. The CBM will be allocated based on the reliability of the interfaces and availability of the resources behind the interfaces. The CBM will be updated at least every 3 years or if system conditions change significantly. MEAG Power's current CBM is shown as follows:

Duke/MEAG	100 MW
FL/MEAG	150 MW
SC/MEAG	45 MW
TVA/MEAG	55 MW

TVA Subregion

CBM/TRM Need and Methodology Statements

November 9, 1998
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TVA Subregion

Transmission System Description

The TVA Subregion of SERC encompasses the bulk transmission facilities of the Tennessee Valley Authority (TVA), Tapoco, Inc., and the United States Corps of Engineers - Nashville District. The geographical coverage of the subregion includes most of Tennessee, northern Alabama, northeastern Mississippi, southwestern Kentucky, and small portions of Georgia, North Carolina, and Virginia. The TVA owns and maintains most of the bulk transmission facilities in the subregion. The majority of the network consists of facilities operated at 161 kV (~ 10,200 miles) and 500 kV (~ 2,400 miles) that transmit power from generation sites to load centers within the subregion. The network is interconnected with neighboring subregions within SERC and to the ECAR and MAIN Regions. The TVA is one of the designated NERC Security Coordinators for the Eastern Interconnection. During 1999, three new generation only control areas became operational within the subregion.

Transmission Service and Open Access

Although TVA is a non-jurisdictional entity, TVA offers Transmission Service in accordance with Good Utility Practice and all applicable laws, including the Energy Policy Act of 1992 and the TVA Act, and reasonably consistent with FERC Order 888. TVA publishes Transmission Service Guidelines that define the terms and conditions for providing these services. TVA currently posts Available Transmission Capacity (ATC) on the MAIN OASIS node.

Transmission Reliability Margin (TRM) Methodology and Application

The uncertainty associated with modeling assumptions made for the calculation of TTC values for a future state are taken into consideration in the application of TRM for the TVA transmission system. Static conditions are simulated to approximate the variable capability of the system through time. The following components of TRM are considered:

- Aggregate Load Forecast Error
- Load Distribution Error
- Variation in facility loadings due to the balancing of load and generation within a control area
- Forecast uncertainty in system topology
- Allowances for parallel “loop flow” impacts
- Allowances for simultaneous path interactions
- Variations in generation dispatch
- Short term Operator response / Operating Reserves

All of these components create uncertainty in the relationship between modeled conditions and actual conditions for any period under study. TVA’s current TRM methodology applies both an import and

export TRM on its three interfaces that have historically been network limited, as opposed to contract path limited. These TRM values serve as a proxy to account for allowances for parallel "loop flow" impacts and simultaneous path interactions. The table below identifies the interfaces and amounts of TRM applied by TVA.

Interface	TRM (MW)
AEP	400
Entergy	400
Southern	500

TVA continues to evaluate its TRM methodology and application to determine if adjustments are warranted.

CBM Methodology and Application

The TVA Capacity Benefit Margin assessment is made by two groups in TVA's Power Resources & Operations Planning Organization. These groups are Transmission Resource Planning, which performs transmission functions, and Generation Resource Planning, which performs support functions.

For the years 2000-2003, the method used by TVA to calculate Capacity Benefit Margin is based on the outage of the largest generating unit plus a calculated amount for regulation and frequency response . The results of a probabilistic evaluation of expected available internal generating capacity compared with projected hourly loads become more significant by 2004, and that method will be used for that year and the following years.

TVA's reliability model factors in the hourly load forecast, seasonal net dependable capacity ratings of the generating units, scheduled maintenance, forced unit and partial outage rates, along with expected levels of interruptible loads. The model uses a loss-of- load reliability index to determine desired reserve levels. Then a projection of capacity deficits or surplus capacity is made.

A probabilistic reserve requirement will be determined based on a reliability index approximately equivalent to an expectation of 0.1 day/year. The expected frequency of hours in which required generation imports would exceed the selected reserve requirement, resulting in interruption of firm load, is approximately 0.1 day per year or one day in ten years. However, in the early years (2000-2003) TVA assumes that the requirements can be met by accounting for the possible unplanned outage of the largest unit plus a calculated amount for regulation and frequency response.

In looking at extreme weather situations, there have been periods when many of the adjoining areas have had almost no surplus generating capacity to sell into TVA. Accessibility to generation in adjoining areas may also be limited by transmission constraints. In cases where most of the surrounding areas are experiencing simultaneous heat or cold waves, or transmission constraints, there might be very little

likelihood of purchasing power from these sources and TVA would have to purchase all the required power from other areas. For this reason, the total Capacity Benefit Margin is estimated to be 150% of the reserve requirement.

The Total Capacity Benefit Margin is prorated to all TVA's interfaces according to historical knowledge of generation purchases, interface contract path limits, and historical First Contingency Incremental Transfer Capability volatility.

TVA conducts analysis to update the Capacity Benefit Margin values every year and the values are reviewed prior to every peak season or as required by conditions on the transmission system. Capacity Benefit Margin values will be adjusted on an as-needed basis.

TVA's current CBM for the 2000 - 2003 time period is 2318 MW.

Use of the Capacity Benefit Margin

During the conditions indicated below, Capacity Benefit Margin can be used to import power by TVA for its native load customers and by other Load Serving Entities that have network load in the TVA control area. Such Load Serving Entities include Cinergy with respect to Bristol, Virginia and Alabama Power Company with respect to its network load in the TVA control area.

During conditions when resources are projected or anticipated to be insufficient to serve TVA's native load customers and such network customers (herein called a "Generation Shortage"), Capacity Benefit Margin may be used to import power on a firm basis to ensure the continued reliability of service to such loads.

A condition requiring use of Capacity Benefit Margin occurs when:

- A Generation Shortage has been declared by TVA or by the Load Serving Entity, and
- There is insufficient posted firm ATC on the interface over which power may be obtained to address the Generation Shortage.

To use the Capacity Benefit Margin (provided conditions are met):

1. The Load Serving Entity experiencing a Generation Shortage shall notify the TVA Control Area System Operator that it has declared a Generation Shortage and that there is insufficient posted firm ATC on the interface over which power may be obtained to address the Generation Shortage.
2. The TVA Control Area System Operator shall notify the TVA Transmission Service Coordinator that the Load Serving Entity has declared a Generation Shortage and that there is insufficient posted firm ATC on the interface over which power may be obtained to address the Generation Shortage.

3. The TVA Transmission Service Coordinator will plan to approve a request for use of Capacity Benefit Margin. The TVA Control Area System Operator will ask the Load Serving Entity to submit a request for use of Capacity Benefit Margin.
4. The Load Serving Entity shall submit a Transmission Schedule using the appropriate transaction serial number for an existing Capacity Benefit Margin set aside.

When not being used, TVA makes Capacity Benefit Margin available on a non-firm basis to all transmission customers.

VACAR Subregion

CBM/TRM Need and Methodology Statements

November 9, 1998

VACAR

The Virginia-Carolinas Reliability Group was formed in 1970 as a result of reliability agreements signed between Carolina Power and Light Company, Duke Power Company, South Carolina Electric and Gas Company, South Carolina Public Service Authority, and Virginia Electric and Power Company. Individual transmission providers within the VACAR subregion have provided their CBM and TRM Need & Methodology Statements in the VACAR section of this document.

Carolina Power & Light (CP&L)

CBM/TRM Need and Methodology Statements

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Carolina Power & Light
CBM-TRM Practices

CBM Practices

Introduction

The electric industry in the United States has developed the most reliable and cost-effective electric service system in the world. That success is due in large part to the ability of neighboring electric systems to rely upon each other for power supply in the event of emergencies that would otherwise threaten reliability. The availability of such emergency power from interconnected systems has allowed electric utilities to avoid overbuilding generation in order to assure system reliability.

In other words, rather than developing stand alone electric systems with 25 to 30 percent capacity margins, the ability to rely upon transmission interconnections for additional power in the event of an emergency has allowed the electric industry to build to 10 to 15 percent capacity margins. Without assurance that interface capability is available for such emergency use, load serving entities could not rely on emergency power from other systems and would have been forced to overbuild generation. CBM is the mechanism that ensures the continuation of this process, which is essential to system reliability and economy.

CBM at CP&L is an amount of a transmission system's interface capability that is reserved for use to meet system needs in the event of an emergency (e.g., unplanned generator outages). ATC is reduced by an amount equal to CBM and, except during an emergency, CBM is not made available for firm transmission reservations. Only in this way can system operators be assured that CBM will be available when needed. At other times, CBM is made available on a non-firm basis to all tariff customers.

The determination of CBM at CP&L is a three-step process:

1) The amount of external generating capacity available to achieve a target reliability level is determined.

2) The total amount of transmission transfer capability necessary to import the external generating reserve is determined.

3) This total amount of transmission transfer capability is then allocated to the specific transmission system interfaces or paths.

Who Performs the CBM Assessment

The Resource Planning staff of the System Planning & Operations department is charged with the responsibility of determining CP&L's CBM requirement.

The Transmission Planning and System Operations staffs of the System Planning & Operations Department at CP&L take into account the CBM requirement developed by the Resource Planning staff and determines the allocation of CBM and TRM to the interfaces.

Methodology used to perform generation reliability analysis

Utilities need a margin of generating capacity available to the system above the capacity used to serve the expected load to ensure reliable service. Generating plants require periodic shutdown to conduct maintenance of facilities and may be unavailable at any given time due to unanticipated equipment failures. Adequate reserve capacity must be available to accommodate this unavailable capacity and also to compensate for higher than expected peak demand due to weather extremes. In addition, some capacity must also be available as operating reserve to maintain the balance between supply and demand on a real-time basis.

The amount of generating reserve needed to maintain a reliable power supply is a function of the unique characteristics of a utility system including load shape, unit sizes, capacity mix, fuel supply, maintenance scheduling, unit availabilities, and the strength of the transmission interconnections with other utilities. There is no one standard measure of reliability that is appropriate for all systems since these characteristics are particular to each individual utility.

CP&L utilizes a multi-area probabilistic analysis to assess generation system reliability. A multi-area analysis takes into consideration the capacity assistance available through interconnections with neighboring electric utilities. Generating reliability depends on the strength of the interconnections, the generation reserves available from the neighboring systems, and also the diversity in loads throughout the interconnected area. Thus, the interconnected system analysis shows the overall level of generation reliability and reflects the expected risk of capacity deficient conditions for supplying load.

Reliability Model

Computer programs are a necessary tool for conducting the generating capacity reliability computations. CP&L uses a two-area probabilistic reliability program capable of calculating loss of load expectation, loss of load hours, and expected unserved energy.

Assumptions

The area considered available to provide assistance to CP&L consists of the VACAR (Virginia-Carolinas Reliability Subregion) companies, American Electric Power, the Tennessee Valley Authority, and the Southern Company. The VACAR companies include Duke Power Company, South Carolina Electric & Gas Company, South Carolina Public Service Authority, Virginia Power Company, and the Southeastern Power Administration. The area is considered a reasonable representation of the capacity support available to CP&L.

Reliability Criteria
A Loss-of-Load Expectation (LOLE) of one day in 10 years is a widely accepted criteria for establishing system reliability. CP&L utilizes a target reliability of 1 day in 10 years LOLE for generation reliability assessment. LOLE can be viewed as the expected number of days that the load will exceed available capacity. Thus, LOLE gives a physical sense of reliability and indicates the number of days that a capacity deficient condition could occur, resulting in the inability to supply customer demand.

CBM Requirement
Based on probabilistic multi-area analysis, CP&L has determined that an emergency transfer capability between 2000 MW and 2500 MW is needed to achieve the target reliability of 1 day in 10 years LOLE. Analysis has found that transfer capability below this amount begins to significantly impact reliability.

Regional Practice
CP&L is a member of the SERC region and VACAR subregion of NERC. The generation reliability assessment methodology used by CP&L is consistent with established industry practice and similar to those methodologies used within SERC and VACAR.

Basis for allocation of CBM to Interfaces

CP&L East Control Area
CP&L has for many years participated in a reserve sharing agreement with other companies within the VACAR subregion of SERC. This agreement requires that each participating VACAR company will provide a Contingency Reserve Commitment to the subregion. The Total Contingency Reserve (TCR) is equal to the largest single resource in the combined areas multiplied by a factor of 1.5. Each participating company is required to maintain their share of the TCR based on a formula that takes into account each company's annual peak demand and largest resource. Contingency reserves are available to member companies to the end of the day or up to 12 hours. CP&L allocates at each interface enough CBM to accommodate each VACAR companies TCR.

CP&L West Control Area
CP&L's western system is very dependent on the interconnection to provide reliable energy to its customers within this control area. The total CBM requirement for CP&L's western system is identified as being 1 times the largest unit within this control area. CBM is only reserved on the interconnections with Duke Power Company.

Operating Practices

The following bullet items provide additional clarification on the operating practices for CBM at CP&L.

- CP&L does not reserve CBM to support off-system network resources.

- CP&L does not reduce its CBM requirements in the near-term operating horizon. CBM values are zero however, within 59 minutes or less.
- CP&L makes available to all tariff customers as non-firm ATC any firm CBM that is not scheduled.
- The firm CBM on the CP&L system is reserved for the benefit of all network load. Access to CBM is controlled by the system operator for the benefit of all network load.
- CP&L's merchant function does not have access to firm CBM.

TRM Practices

Introduction

TRM at CP&L is defined to as the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM at CP&L 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.

Specifically, CP&L uses the Short-term Operator Response/Operating Reserves component to determine the CP&L TRM requirements. 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.

Who Performs the TRM Assessment

The Transmission Planning and System Operations staff of the System Planning & Operations Department determines the allocation of TRM to the interfaces.

Methodology Used to Determine and Allocate TRM

CP&L determines TRM by simulating 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 becomes the operating reserve sharing component of TRM.

Operating Practices

CP&L applies TRM to specific interfaces resulting in a reduction in transfer capability.

CP&L does not apply TRM to paths limited by contract-based interconnection ratings since the capability of such a path is not subject to the uncertainties for which TRM is intended.

CP&L does not allow TRM to be sold on a firm or non-firm basis as doing so would degrade system security.

CP&L maintains an export TRM of 350 MW with each of its VACAR company interfaces. This is to provide transmission to coincide with CP&L's reserve obligation to meet the VACAR Reserve Sharing Agreement.

CP&L-EASTERN AREA CBM, TRM & NETWORK RESERVATIONS

	Path		March-00			April-00			May-00		
Control Area	From	To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLE Imports	APCO	CPLE	0	97	455	0	97	455	0	97	455
	DUKE	CPLE	524	351	150	524	351	250	524	351	250
	SCEG	CPLE	197	129	0	197	129	0	197	129	0
	SCPSA	CPLE	181	146	9	181	146	9	181	146	9
	VAPOW	CPLE	441	378	110	441	378	110	441	378	110
CPLE Exports	CPLE	APCO	0	0	0	0	0	0	0	0	0
	CPLE	DUKE	0	350	200	0	350	200	0	350	200
	CPLE	SCEG	0	350	0	0	350	0	0	350	0
	CPLE	SCPSA	0	350	0	0	350	0	0	350	0
	CPLE	VAPOW	0	350	151	0	350	151	0	350	151

	Path		June-00			July-00			August-00		
Control Area	From	To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLE Imports	APCO	CPLE	0	97	455	0	97	455	0	97	455
	DUKE	CPLE	524	351	250	524	351	250	524	351	250
	SCEG	CPLE	197	129	0	197	129	0	197	129	0
	SCPSA	CPLE	181	146	9	181	146	9	181	146	9
	VAPOW	CPLE	441	378	410	441	378	410	441	378	410
CPLE Exports	CPLE	APCO	0	0	0	0	0	0	0	0	0
	CPLE	DUKE	0	350	200	0	350	200	0	350	200
	CPLE	SCEG	0	350	0	0	350	0	0	350	0
	CPLE	SCPSA	0	350	0	0	350	0	0	350	0
	CPLE	VAPOW	0	350	151	0	350	151	0	350	151

	Path		September-00			October-00			November-00		
Control Area	From	To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLE Imports	APCO	CPLE	0	97	455	0	97	455	0	97	455
	DUKE	CPLE	524	351	250	524	351	250	524	351	150
	SCEG	CPLE	197	129	0	197	129	0	197	129	0
	SCPSA	CPLE	181	146	9	181	146	9	181	146	9
	VAPOW	CPLE	441	378	410	441	378	110	441	378	110
CPLE Exports	CPLE	APCO	0	0	0	0	0	0	0	0	0
	CPLE	DUKE	0	350	200	0	350	200	0	350	200
	CPLE	SCEG	0	350	0	0	350	0	0	350	0
	CPLE	SCPSA	0	350	0	0	350	0	0	350	0
	CPLE	VAPOW	0	350	151	0	350	151	0	350	151

	Path		December-00			January-01			February-01		
Control Area	From	To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLE Imports	APCO	CPLE	0	97	455	0	97	455	0	97	455
	DUKE	CPLE	524	351	150	524	351	150	524	351	150
	SCEG	CPLE	197	129	0	197	129	0	197	129	0
	SCPSA	CPLE	181	146	9	181	146	9	181	146	9
	VAPOW	CPLE	441	378	110	441	378	110	441	378	110
CPLE Exports	CPLE	APCO	0	0	0	0	0	0	0	0	0
	CPLE	DUKE	0	350	200	0	350	200	0	350	200
	CPLE	SCEG	0	350	0	0	350	0	0	350	0
	CPLE	SCPSA	0	350	0	0	350	0	0	350	0
	CPLE	VAPOW	0	350	151	0	350	151	0	350	151

	Path		March-01		
Control Area	From	To	CBM	TRM	Network Reservations
CPLE Imports	APCO	CPLE	0	97	455
	DUKE	CPLE	524	351	150
	SCEG	CPLE	197	129	0
	SCPSA	CPLE	181	146	9
	VAPOW	CPLE	441	378	110
CPLE Exports	CPLE	APCO	0	0	0
	CPLE	DUKE	0	350	200
	CPLE	SCEG	0	350	0
	CPLE	SCPSA	0	350	0
	CPLE	VAPOW	0	350	151

CP&L Network Reservations include:

AEP	250 MW from AEP for Rockport Unit #2 Purchase
AEP	205 MW from AEP for NCEMC load
Duke	150-250 MW through Duke for CPLW-to-CPLE transfer
Duke	200 MW through Duke for CPLE-to-CPLW transfer
SCPSA	9 MW from SCPSA for Charleston Resource Cogen
VAPOW	95 MW from VAPOW for SEPA Kerr Dam Project
VAPOW	10 MW from VAPOW to serve Tri-towns load
VAPOW	5 MW from VAPOW to serve Sharpsburg load
VAPOW	300 MW from VAPOW for native load purchase from PECO Energy
VAPOW	6 MW to VAPOW to serve Littleton load
VAPOW	145 MW to VAPOW to serve NCEMPA load

CP&L-WESTERN AREA CBM, TRM & NETWORK RESERVATIONS

			March-00			April-00			May-00		
Control Area	Path From	Path To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLW Imports	APCO	CPLW	0	42	250	0	42	250	0	42	250
	DUKE	CPLW	0	134	200	0	134	200	0	134	200
	TVA	CPLW	0	0	14	0	0	14	0	0	14
CPLW Exports	CPLW	APCO	0	0	0	0	0	0	0	0	0
	CPLW	DUKE	0	0	150	0	0	250	0	0	250
	CPLW	TVA	0	0	0	0	0	0	0	0	0

			June-00			July-00			August-00		
Control Area	Path From	Path To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLW Imports	APCO	CPLW	0	42	250	0	42	250	0	42	250
	DUKE	CPLW	0	134	200	0	134	200	0	134	200
	TVA	CPLW	0	0	14	0	0	14	0	0	14
CPLW Exports	CPLW	APCO	0	0	0	0	0	0	0	0	0
	CPLW	DUKE	0	0	250	0	0	250	0	0	250
	CPLW	TVA	0	0	0	0	0	0	0	0	0

			September-00			October-00			November-00		
Control Area	Path From	Path To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLW Imports	APCO	CPLW	0	42	250	0	42	250	0	42	250
	DUKE	CPLW	0	134	200	0	134	200	0	134	200
	TVA	CPLW	0	0	14	0	0	14	0	0	14
CPLW Exports	CPLW	APCO	0	0	0	0	0	0	0	0	0
	CPLW	DUKE	0	0	250	0	0	250	0	0	150
	CPLW	TVA	0	0	0	0	0	0	0	0	0

			December-00			January-01			February-01		
Control Area	Path From	Path To	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations	CBM	TRM	Network Reservations
CPLW Imports	APCO	CPLW	0	42	250	0	42	250	0	42	250
	DUKE	CPLW	0	134	200	0	134	200	0	134	200
	TVA	CPLW	0	0	14	0	0	14	0	0	14
CPLW Exports	CPLW	APCO	0	0	0	0	0	0	0	0	0
	CPLW	DUKE	0	0	150	0	0	150	0	0	150
	CPLW	TVA	0	0	0	0	0	0	0	0	0

			March-01		
Control Area	Path From	Path To	CBM	TRM	Network Reservations
CPLW Imports	APCO	CPLW	0	42	250
	DUKE	CPLW	0	134	200
	TVA	CPLW	0	0	14
CPLW Exports	CPLW	APCO	0	0	0
	CPLW	DUKE	0	0	150
	CPLW	TVA	0	0	0

CP&L Network Reservations include:

AEP	250 MW from AEP for Rockport Unit #2 purchase
TVA	14 MW from TVA for Cumberland Project (SEPA)
Duke	150-250 MW through Duke for CPLW-to-CPLE transfer
Duke	200 MW through Duke for CPLE-to-CPLW transfer

Duke Energy Corporation

CBM/TRM Need and Methodology Statements

November 9, 1998
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PURPOSE

The purpose of this statement is to document the philosophy and methodology that Duke Energy uses to determine its requirements for transmission margins. It is Duke Energy's intention to formulate its methodology to be consistent with the FERC Order on CBM, the draft NERC Standards and the SERC Guidelines for Transmission Capability Margins.

INTRODUCTION

NERC

On November 9, 1965 a blackout put 30 million people across the Northeastern United States and Ontario, Canada in the dark. In an effort to prevent this type of blackout from ever happening again, electric utilities formed the North American Electric Reliability Council (NERC) in 1968 to promote the reliability of the electricity supply for North America. This mission is accomplished by working with all segments of the electric industry as well as customers. NERC reviews the past for lessons learned, monitors the present for compliance with policies, standards, principles, and guides, and assesses the future reliability of the bulk electric systems.

The membership of NERC is unique. As a not-for-profit corporation, NERC's owners are ten Regional Councils. The members of these Regional Councils come from all segments of the electric industry - investor-owned, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, power marketers, and electricity customers. These entities account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.

SERC

The Southeastern Electric Reliability Council (SERC) is the regional organization for the coordination of the operation and planning of the bulk power electric systems in the southeastern United States. The purpose of this coordination is to assure that the planning and operation of individual electric systems does not adversely affect other systems and that opportunities for improved system performance are identified.

SERC is one of the ten regional reliability councils constituting the North American Electric Reliability Council (NERC). NERC came into being with an agreement dated June 1, 1968, signed by 12 regional and area organizations which included from the southeast the CARVA Pool, the Tennessee Valley Authority (TVA), The Southern Company, and the Florida Electric Power Coordinating Group.

In 1969, discussions among representatives of these 4 entities indicated that the interest of reliability of the bulk power system in the southeast would be better served by the creation of a regional reliability council with broader membership. This was particularly true for the smaller systems who were not represented directly in the 4 organizations from the area which had signed the NERC agreement. This

led to the signing of the SERC Agreement on January 14, 1970, by 22 electric systems.
Because of the geographic size of the region and the diversity among its parts, the region was divided into subregions for data reporting purposes. These were the VACAR subregion (Virginia and the Carolinas), the TVA subregion, and the Southern subregion (Georgia, Alabama, and part of Mississippi and panhandle of Florida), and the Florida Peninsula.

In September of 1996, the Florida peninsula became a separate NERC Region (FRCC).

Effective January 1, 1998, the Operating Companies of Entergy became official members of SERC. This added a fourth sub-region to SERC. Also joining SERC were Associated Electric Cooperative and CAJUN Electric Power Cooperative.

SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, independent power producers, and power marketers. SERC currently has 39 member systems and 32 associate members. The Region, represented by the Council, is located in 13 states in the Southeastern United States and covers an area of approximately 464,000 square miles. The membership is comprised of investor-owned, municipal, cooperative, state and federal systems, independent power producers, and power marketers.

VACAR

The Virginia-Carolinas (VACAR) Reliability Group was formed in 1970 as a result of reliability agreements signed between Carolina Power and Light Company, Duke Power Company, South Carolina Electric and Gas Company, South Carolina Public Service Authority, and Virginia Electric and Power Company.

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 the Federal Energy Regulatory Commission (FERC) requirements and industry needs. In defining the components that make up ATC, a number of new terms were introduced. Among these terms were two transmission margins to recognize uncertainty inherent in the interconnected power system. These two margins are known as the Transmission Reliability Margin (TRM) and the Capacity Benefit Margin (CBM). In 1999 SERC identified a requirement to have a regional methodology for the determination of TRM and CBM. This requirement was necessitated by the following events:

- The NERC Available Transfer Capability Working Group (ATCWG) performed a review of each of the ten region's ATC determination procedures and their compliance with NERC principles. The NERC ATCWG determined that Transmission Providers were not using a common philosophy with regard to the necessity of margins and they were not using a consistent methodology to calculate margins across the Interconnections. Because of this disparity and the desire to encourage a convergence of margin methodologies, the NERC ATCWG published a revised set of definitions for TRM and CBM.

- The NERC ATCWG recommended that each region develop a region-wide methodology for the determination of transmission margins. In the SERC response to the NERC review of the SERC Region, SERC developed an action plan that included developing a regional methodology for determining TRM and CBM. Both the SERC ATCWG and the SERC Engineering Committee approved this action plan in June 1999.

- NERC is also developing Planning Standards that include standards on the determination of Transfer Capability. The draft standards identify the need to have regional methodologies for TRM and CBM determination and have those methodologies adhered to by Transmission Providers within the region.

- The FERC issued a ruling (Docket No. EL99-46-000) that directed Transmission Providers, working through NERC to complete the process to establish a standardized methodology for deriving CBM by the end of 1999.

To meet the requirements of the SERC Action Plan, the NERC Planning Standards, and the FERC requirements, the SERC Engineering Committee approved the SERC Guidelines for Transmission Capability Margins on December 8, 1999.

Subsequent to the approval of the SERC Guidelines, Duke Energy has reviewed and revised its practices with regard to TRM and CBM. This CBM / TRM Need and Methodology Statement documents Duke Energy's methodology for the determination and posting of TRM and CBM.

DUKE ENERGY

System Description:

Duke Energy operates a NERC Control Area and is a Transmission Provider within the VACAR Subregion of SERC. Duke Energy also serves as the VACAR South Security Coordinator for the Duke, South Carolina Electric & Gas and South Carolina Public Service Authority Control Areas.

Duke Energy has interconnections with American Electric Power, Carolina Power & Light, South Carolina Electric & Gas, South Carolina Public Service Authority, the Southern Company, the Southeastern Power Administration, the Tennessee Valley Authority, and Yadkin.

Compliance/Consistency with NERC ATC Principles document.

A. *Commercially viable results*:

Duke Energy's determination of Total Transfer Capability (TTC) recognizes constraints and limitations both internal and external to the Duke Transmission System. The ATC values that Duke calculates and posts are based on the TTC values. Duke Energy's goal in the posting of ATC is to maximize the utilization of the transmission grid while minimizing congestion on all transmission paths. Duke Energy's calculation of the ATC Commercial Viability Indices showed that over 95 percent of the valid requests of transmission service on Duke Energy's System were accepted and an even higher percentage of the confirmed requests were continued to completion (i.e., not curtailed).

B. *Recognize time-variant conditions:*

Joint Transmission Studies performed in the VACAR-AEP-Southern-TVA-Entergy (VAST) Study Group recognize the effects of all firm and some expected transfers. In addition, Duke Energy performs sensitivity studies that evaluate the impact of simultaneous transfers on transmission constraints. The combination of these studies coupled with the real-time monitoring of the transmission system enables the Duke Transmission Provider to adjust ATC to accommodate current and expected system conditions.

C. *Impact of Source/Sink:*

Both VAST Studies and internal Duke Energy Studies model system transfers based on their Control Area Source and Sink. In addition, Duke will not accept or evaluate any transmission service request unless the Control Area Source and Sink are identified in the request.

D. Wide area coordination:

TTC values and ATC information are coordinated throughout the SERC region. The majority of this coordination is performed through the VAST Study Group using the OASIS Support Studies. The study effort provides a forum for Transmission Providers to exchange outage, load, generation, reservation, margin and other information on a scheduled basis. Duke Energy also participates in the seasonal VEM (VACAR-ECAR-MAAC) studies where similar information is exchanged.

In addition to the VAST and VEM studies, Duke Energy is a participant in the VST studies. The VST Study Group, under the direction of the VST Steering Committee, is responsible for preparing future year base cases for a variety of purposes. These cases can be used by the Duke Energy and other VST Transmission Providers to perform transfer studies from which TTC and ATC values can be derived for this horizon. Each year or as commissioned by the VST Steering Committee, the VST Study performs a future year study.

Duke Energy is populating and/or retrieving information to enhance the calculation of ATC through the following NERC Mechanisms:

- The Interregional Security Network (ISN),
- The System Data Exchange (SDX),
- Security Coordinator Information System (SCIS),
- Interchange Distribution Calculator (IDC),
- Transfer Distribution Factor (TDF) Viewer, and
- The Base Cases of the Multi-regional Modeling Working Group (MMWG).

Finally, as longer-term (generally greater than a month) transmission service is requested, Duke Energy is communicating and coordinating information with neighboring providers prior to accepting and confirming the reservation.

E. *Conformity to regional policies:*

Duke Energy's ATC calculations conform to and/or are compliant with the following:

- NERC ATC Definitions and Determination Document;
- The SERC ATC Coordination Procedures;
- The NERC Transmission Capability Margins ATCWG Position Paper;
- The SERC Guidelines for Transmission Capability Margins;
- The VST, VEM, and VAST procedural manuals;
- The VACAR operating manual; and
- NERC and SERC policies, principles, guidelines and standards.

F. *Accommodating uncertainties:*

Duke Energy accounts for uncertainties in actual system conditions when determining ATC and ensuring the integrity of the transmission system and generation supply.

CBM / TRM

CBM

The Capacity Benefit Margin (CBM) utilized within SERC is 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 that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission capacity preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Duke Energy has not defined a need for CBM on any of its interfaces in the Operating, Operational Planning, or Planning Horizons. The importing and exporting CBM on all interfaces is set to zero. The reasoning is as follows:

- ⇒ Duke Control Area uses 12-hour line ratings in its calculation of TTC. When operating the system, Duke uses short-term or one-hour line ratings where available. This affords an operating margin for unexpected conditions or inaccuracies in data used in the TTC calculations.
- ⇒ Duke Control Area uses the single worst transmission contingency when calculating all TTCs. These transmission contingencies may be either inside Duke Power's Control Area or outside its boundaries. External contingency limits to TTC are verified with the owning Control Area before they are posted. Duke Energy uses adverse generation participation when calculating import TTC. This methodology is consistent with Duke Energy's planning criteria, and it allows Duke to operate the system consistent with NERC operating guidelines. Adhering to the criteria reduces the need to maintain additional margins on Duke's interconnections.
- ⇒ In general, there are few limits to transfer that have been identified within the Duke Control Area. This fact further reduces the need for Duke to include CBM in its calculation of ATC.

Duke Energy has posted its CBM amounts (values) for each path that it posts ATC and where Duke Energy is either the source or the sink for the reservation. When Duke is requested to transmit power across its transmission system on a

"through path," the lesser of the ATCs at the Point of Delivery (POD) and at the Point of Receipt (POR) is used to post ATC and evaluate whether or not the request can be accommodated. The ATC's for the POD and POR have the declaration of CBM embedded in the calculation based on the methodology found in the NERC "Available Transfer Capability Definitions and Determination" reference document.

Duke Energy does not address generation reliability assessments through the utilization of CBM so this document does not contain the methodology and assumptions that Duke Energy uses for generation reliability requirements.

Duke Energy does not make CBM available for use on a firm basis by market entities including Duke Energy's affiliated marketer; however, any CBM that Duke has posted would be offered on the Duke Energy OASIS node as non-firm (recallable) ATC.

TRM

The Transmission Reliability Margin (TRM) utilized within the SERC Region is 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.

For Duke Energy, TRM is dependent upon the direction of the transfer capability across an interface. For imports, each VACAR interface is set equal to the opposing control area's share of the VACAR reserve requirement. The importing TRM on interfaces with non-VACAR control areas is set to zero until such time as contingency reserves are identified and contracted for on those interfaces. The TRM for exports on each interface is set equal to Duke's contractual obligation to meet the opposing Control Area's TRM requirement.

Duke Energy's position is that in order to declare TRM there should be a contractual obligation for reserves. When Duke has a contractual transmission reservation obligation to supply and/or receive capacity other than reserves, then Duke will show this amount as a discrete transmission reservation as opposed to TRM. For that reason, existing and new declared network resources are not counted under TRM.

The basis for the selection of paths for which Duke Energy has set aside TRM is a contractual obligation to supply and receive operating reserves to and from the members of Virginia-Carolinas Reliability Group. The contractual requirements for reserve sharing are reviewed and updated on an annual basis.

An emergency within the Virginia-Carolinas Reliability Group is the loss of a resource including the loss of a generation unit or plant or purchase (capacity). In the event of such an emergency loss, each system will make available to the other, up to the total available Contingency Reserve capacity on its system and, upon request, will attempt to obtain capacity and/or energy from a third party system.

Duke Energy maintains sufficient reserves to meet the reserve requirements of the Duke Power Control Area. In the event that a non-Duke Load Serving Entity located within the Control Area has need of reserves, Duke will arrange for those reserves to be delivered under its open access transmission tariff.

Application of TRM and CBM

Duke Energy does not require a separate reservation for contingency reserve transactions that utilize the TRM reservations. The ATC values that Duke posts include VACAR contingency reserves. Duke's ATC values do not change when contingency reserves are delivered because the reservation only moves from TRM (reserved) to NATC (firm scheduled). Duke will resell TRM and CBM on a non-firm basis only.

Netting of Schedules and/or Reservations

Duke Energy only nets RATC (Non-firm) reservations that have an associated energy schedule. In addition, Duke only nets on transmission paths where the contract path rating is the limit, such as Southern (2350 MW), AEP (1835 MW) and TVA (217 MW). Duke Energy does not net firm schedules or reservations.

Losses

Loss schedules are treated as a separate schedule within the EMS system. Duke Energy does not show an explicit transmission reservation of ATC on OASIS for losses.

Commercial Paths, Contract Paths & Non-contiguous Paths

Duke Energy calculates non-simultaneous transfer capability into and out of the Duke Control Area. For a wheel-through transaction, the path would be the lesser of the in and out ATC on the requested path. However, Duke evaluates transmission service requests based on the source, sink and path. Duke does not post non-contiguous transfer capability, but does evaluate requests for transmission service that involve non-contiguous sources and sinks.

Quantitative Data by Path

	2000 Winter / Summer TRM	2000 Winter / Summer CBM
AEP to Duke	0	0
Duke to AEP	0	0
CP&LE to Duke	351	0
Duke to CP&LE	324	0
CP&LW to Duke	0	0
Duke to CP&LW	200	0
SCE&G to Duke	195	0
Duke to SCE&G	524	0
SCPSA to Duke	181	0
Duke to SCPSA	524	0
TVA to Duke	0	0
Duke to TVA	0	0
Southern to Duke	0	0
Duke to Southern	0	0
SEPA (Hartwell & Thurmond) to Duke	0	0
Duke to SEPA (Hartwell & Thurmond)	0	0
Yadkin to Duke	0	0
Duke to Yadkin	0	0

South Carolina Electric & Gas (SCE&G)

CBM/TRM Need and Methodology Statements

November 9, 1998
Revised: April 12, 2000

SOUTH CAROLINA ELECTRIC & GAS

System Description

South Carolina Electric & Gas Company (SCE&G) operates a NERC Control Area and is a Transmission Provider within the VACAR Subregion of SERC. SCE&G's interconnection system with other control areas consist of the following:

	230kV	115kV
Carolina Power & Light	2	1
Duke Energy	2	2
South Carolina Public Service Authority	4	5
Southern Company	1	1
Southeastern Power Administration	0	1
Total	9	10

Compliance/Consistency with NERC ATC Principles document

A. *Commercially viable results:*
SCE&G's determination of Total Transfer Capability (TTC) recognizes constraints and limitations both internal and external to the SCE&G Transmission System. The ATC values that SCE&G calculates and posts are based on the TTC values. SCE&G's goal in the posting of ATC is to maximize the utilization of the transmission grid while minimizing congestion on all transmission paths.

B. *Recognize time-variant conditions:*
Joint Transmission Studies performed in the VACAR-AEP-Southern-TVA-Entergy (VAST) Study Group recognize the effects of all firm and some expected transfers. In addition, when major variations occur in the expected generator availability or system topology, SCE&G performs sensitivity studies that evaluate the impact of these variances on ATC.

C. *Impact of Source/Sink:*
Both VAST Studies and internal SCE&G Studies model system transfers based on their Control Area Source and Sink. In addition, SCE&G will not accept or evaluate any transmission service request unless the Control Area Source and Sink are identified in the request.

D. *Wide area coordination:*
TTC values and ATC information are coordinated throughout the SERC region. The majority of this coordination is performed through the VAST Study Group using the OASIS Support Studies. The study effort provides a forum for Transmission Providers to exchange outage, load, generation, reservation, margin and other information on a regular basis.

E. *Conformity to regional policies:*

SCE&G's ATC calculations conform to the NERC ATC Definitions and Determination Document; the SERC ATC Coordination Procedures; the NERC and SERC planning and operating policies, principles and guidelines; the VST and VAST procedural manuals; and the VACAR operating manual.

F. *Accommodating uncertainties:*
SCE&G accounts for uncertainties in actual system conditions when determining ATC and ensuring the integrity of the transmission system and generation supply.

Consistency with NERC Planning Standards

SCE&G's practices regarding the determination and coordination of ATC are consistent with the current approved NERC Planning Standards. SCE&G has developed plans to comply with all NERC Planning Standards when they are implemented.

Consistency with SERC ATC Coordination Procedures

SCE&G's practices regarding the determination and coordination of ATC are consistent with the SERC ATC Coordination Procedures.

CBM Determination

SERC defines Capacity Benefit Margin (CBM) 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 that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission capacity preserved as CBM is intended to be used by the LSE only in times of emergency generation.

SCE&G has not determined a need for CBM in the Operating or Operational Planning horizons. The importing CBM on all interfaces is set to zero.

TRM Determination

SERC defines Transmission Reliability Margin (TRM) 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 operations as system conditions change. All transmission system users benefit from the preservation of TRM by Transmission Providers.

Imports

SCE&G uses generation sensitivity studies and the modeling of the VACAR Reserve Sharing Agreement to determine import TRM values.

Generation sensitivity studies are used as a "proxy" to address uncertainties associated with items such as variations in generation dispatch, allowances for parallel path "loop flow" impacts, and allowances for simultaneous path interactions, as discussed in the SERC Guidelines for Transmission Capability Margins. Modeling of the VACAR Reserve Sharing Agreement is used to determine if additional transmission capability above the amount determined in the generation sensitivity studies should be preserved to accommodate the reserve sharing agreement. The SERC Guidelines for Transmission Capability Margins refers to this as Short-term Operator Response / System Response / Operating Reserves including Reserve-Sharing programs. Therefore, all TRM components as discussed in the SERC Guidelines for Transmission Capability Margins are effectively considered in these calculations.

Generation sensitivity studies conducted determined the maximum response for each interface as indicated in the following table:

	CP&L	Duke	Santee	Southern
Base Flow	148 out	136 out	375 out	263 in
Generator Sensitivity	**Interface Response (D MW)**			
VC Summer	93	302	73	155
AM Williams	55	98	326	120
Cope	76	80	152	102
Wateree #1	84	87	120	66
Largest Δ MW	93	302	326	155

Modeling of the VACAR Reserve Sharing Agreement determined the maximum response for each interface as indicated in the following table:

	CP&L	Duke	Santee	Southern
Base Flow	148 out	136 out	375 out	263 in

Reserve Sharing	**Interface Response (D MW)**			
VC Summer				
Buy from CP&L	57	176	113	22
Buy from Duke	55	258	123	17
Buy from Santee	18	64	113	3
Buy from Virginia	69	219	141	34
AM Williams				
Buy from CP&L	47	55	226	42
Buy from Duke	30	106	264	42
Buy from Santee	8	2	171	7
Buy from Virginia	44	67	283	58
Cope				
Buy from CP&L	75	91	140	53
Buy from Duke	77	153	158	57
Buy from Santee	27	20	127	13
Buy from Virginia	91	113	175	73
Wateree #1				
Buy from CP&L	87	113	133	33
Buy from Duke	92	178	146	30
Buy from Santee	33	32	123	2
Buy from Virginia	106	141	166	48
Largest Δ MW	106	258	283	73

The higher of these two determinations is the amount of transmission capability preserved as import TRM on each interface.

Exports

The TRM values for SCE&G exports on each interface are set equal to the opposing control area's requirement.

Wheel-throughs

The TRM values for SCE&G wheel-throughs are the greater of the import and export TRM values on the requested path.

CBM / TRM Values

The following table shows SCE&G's CBM and TRM values for all transmission paths as posted on SCE&G's OASIS.

	Path		TRM	CBM
Control Area	From	To	(MW)	(MW)
SCE&G Imports	CP&L	SCE&G	106	0
	Duke	SCE&G	302	0
	SCPSA	SCE&G	326	0
	Southern	SCE&G	155	0
SCE&G Exports	SCE&G	CP&L	197	N/A
	SCE&G	Duke	197	N/A
	SCE&G	SCPSA	197	N/A
	SCE&G	Southern	0	N/A
SCE&G Wheel-throughs	CP&L	Southern	106	N/A
	Southern	CP&L	197	N/A

Application of TRM and CBM

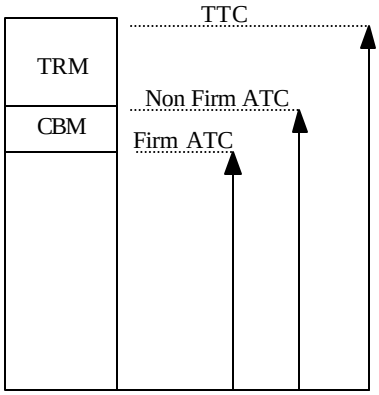
SCE&G's calculation of Firm ATC uses both TRM and CBM (currently CBM is set equal to zero) and can be expressed as:

Firm ATC = TTC – TRM – CBM – firm reservations

SCE&G's calculation of Non-firm ATC uses only TRM and can be expressed as:

Non-firm ATC = TTC – TRM – firm reservations – non-firm reservations

SCE&G will resell CBM on a non-firm basis only. TRM is not sold.



Netting of Schedules and/or Reservations

SCE&G nets only Non-firm reservations and/or schedules on paths where the contract path rating is the limit. SCE&G does not net firm schedules or reservations.

Commercial Paths, Contract Paths & Non-contiguous Paths

SCE&G calculates and post transfer capability and availability on two wheel-through transaction paths. CP&L to Southern and Southern to CP&L.

General

SCE&G's transmission transfer capability, TRM and CBM assessments are performed by SCE&G's Transmission Planning Department.

SCE&G continually performs generation reliability assessments. These assessments consider the amount of capacity required by the VACAR Reserve Sharing Agreement, the Contingency Reserve which reflects the forced outage rates of SCE&G generating units and the Weather Component which considers the need to plan for extreme weather. SCE&G uses loss-of-load probability criteria to support its assessments. SCE&G has not determined if their methodology is consistent with other practices in the region. SCE&G's expectation is that there are differences. SCE&G's methodology is reported to and reviewed by the South Carolina Public Service Commission. Currently SCE&G does not withhold transmission transfer capability that may be needed in the future to accommodate purchases for growth in system load.

Santee Cooper

CBM/TRM Need and Methodology Statements

November 9, 1998
Revised: August 4, 2000

Transmission Reliability Margin Methodology

Santee Cooper

Santee Cooper uses a calculation methodology based on simulated power flows resulting from generation sensitivity analysis and operating reserve requirements. Santee Cooper's process estimates the greatest natural response on each interface due to the loss of the most critical generating unit impacting the interface. The import TRM is set equal to this natural response as a proxy to address uncertainties associated with items such as load forecast error, load distribution error, forecast uncertainty, parallel path and loop flow impacts, variations in generation dispatch, etc.

Santee Cooper then simulates the receipt of operating reserves under the VACAR Reserve Sharing Agreement from other VACAR control areas to replace a portion of the generation associated with the outaged unit. For Santee Cooper, this portion is calculated to be the total generation outage less Santee Cooper's internal contribution of contingency reserves, which is currently 181 MW.

In summary, Santee Cooper uses TRM based on generation reserves to import part of its operating reserve requirements and establishes a flow-based TRM component on the interfaces as needed to ensure operating reserve can be reliably imported. Santee Cooper recognizes the other VACAR Control Area's declarations of import TRM and makes no attempt to calculate those values. TRM values are coordinated among the VACAR companies for use in calculating ATC values.

Santee Cooper utilizes the most current seasonal (summer or winter) VAST Base cases used in the OASIS Support Studies as a starting reference point in calculating TRM and CBM values for posting on OASIS. TRM values are calculated every six months and revisions are updated and coordinated with Santee Cooper's neighboring control areas.

Since Santee Cooper's TRM methodology utilizes flow-based processes, Santee Cooper has not offered TRM on a non-firm basis. At present, Santee Cooper does not carry CBM on any interfaces. Santee Cooper's TRM and CBM values can be derived for values posted on its OASIS site as follows:

TRM = TTC - (non-firm hourly ATC) - (confirmed schedules)

CBM = 0

Virginia Power/North Carolina Power

CBM/TRM Need and Methodology Statements

November 9, 1998
Revised: March 3, 2000

Virginia Power/North Carolina Power

Virginia Power/North Carolina Power (normally referred to as Virginia Power) serves two million customers in Virginia and eastern North Carolina. VP is located in the VACAR Subregion of SERC, and serves as the VACAR North Security Coordinator. The VP transmission network includes 500 kV, 230 kV, 138 kV, and 115 kV lines. VP has one 500 kV, four 230 kV, and two 115 kV interconnections with CP&L-East to the south; one 500 kV and six 138 kV interconnections with AEP to the west; five 500 kV, one 138 kV, and one 115 kV interconnection with AP to the north west ; and one 500 kV and one 230 kV interconnection with PJM to the north.

Virginia Power participates with the other SERC transmission providers in the VAST OASIS Study process. This process creates jointly developed quarterly cases for use in ATC calculation and develops TTC and ATC numbers for the next 13 months for intra-SERC transfers. Each quarter, a new quarterly case is created for the season covering months eleven through 13. At the same time, each participant has the opportunity to update the existing cases for the next three quarters covering months two through 10. The participating control areas jointly develop the cases and calculate FCTTCs.

VP uses these VAST OASIS seasonal cases to create monthly cases which reflect shorter term maintenance outages and more recent knowledge of transactions. These monthly cases are then used to update the month two through thirteen ATC numbers monthly. TTCs and ATCs are calculated for paths to and from VP and its neighboring control areas: CP&L-E, AEP, AP, and PJM. The calculation methodology applies single contingency outage criteria on Virginia Power facilities and tie lines and selected critical contingencies in adjacent control areas and monitors Virginia Power facilities and tie lines. The calculation complies with NERC ATC calculation methodology and conforms to NERC Planning Standard I.E. as well as SERC criteria.

Virginia Power calculates non-simultaneous TTCs into, out of, and through the Virginia Power Control Area. Virginia Power calculates ATCs in accordance with the equations in the NERC ATC Document. In addition, Virginia Power decrements ATCs on direct-connect paths based on the distributed effects of wheel-through reservations and schedules. ATCs on wheel-through paths are decremented strictly on a contract path basis. All reservations and schedules are monitored to ensure that the NERC tie-line transfer limits are not exceeded. Virginia Power does not post non-contiguous transfer capability. Virginia Power does not net firm schedules or reservations but does net non-firm schedules in the operating horizon and non-firm reservations in the planning horizon.

Before 16:00 of the current day, the operating horizon is defined as the remainder of the current day. After 16:00 of the current day, the operating horizon becomes the reminder of the current day plus all of tomorrow. The time period beyond the operating horizon is defined as the planning horizon. For the operating horizon and the three days following, Virginia Power uses the STrLim application to calculate TTCs. StrLim was developed by Cegelec ESCA and uses a state estimator solution as a base case. (In the event that StrLim solutions cannot be obtained in a timely manner, the TTCs derived from

the monthly studies mentioned above are used as default values.) The TTCs calculated by StrLim are updated daily. The ATCs calculated in the operating horizon are updated hourly and on demand.

VP participates in the SDX data exchange program and the iIDC to exchange system data on projected loads, generator status, scheduled transfers, and scheduled facility outages with neighboring control areas. Prior to development of the SDX system, system data was exchanged with neighboring control areas via the ORNS (Operating Representatives of the Northeast Systems) data exchange. This data was used by Allegheny Power to calculate voltage curves to determine voltage limits for ECAR to VP and PJM transfers as specified by the Reliability Coordination Plan. ECAR to VP and ECAR to PJM transfers were curtailed or frozen according to the provisions of the RCP to maintain the security of the interconnected transmission system. Now such curtailments would be done through the TLR process. However, if the cuts cannot be accomplished quickly enough by TLR, the RCP would be initiated as a local control procedure to ensure the reliability of the system until the necessary curtailments could be implemented through the TLR process.

VP also enters monthly TTC and ATC data into the ECAR ATC coordination program and sends TTC and ATC information to PJM. Since PJM performs their ATC calculations using West to PJM and PJM to West paths rather than PJM to VP and VP to PJM paths, the calculated TTC and ATC numbers on these paths cannot be directly coordinated.

Following is a discussion of Virginia Power's basis for determining CBM and TRM.

Basis for the Determination of TRM and CBM

An Explanation of the Considerations Behind the Values of Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) Selected for Application in the Available Transfer Capability (ATC) Equations in the Transmission Access Management System (TAMS)

Jack Kerr/Nelson Burks
Virginia Power
March 3, 2000

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Introduction

On July 28, 1999, the FERC issued an order directing transmission providers, working through NERC, to complete by the end of 1999 a process to standardize the methodology for deriving CBM. NERC subsequently submitted a questionnaire to the regional reliability councils asking each Region if they could develop a standardized Regional methodology for determining CBM by the end of 1999, based on the "white paper" on Transmission Capability Margins and Their Use in ATC Determination approved by the NERC Adequacy Committee in July, 1999. In its response, SERC indicated that its Engineering and Operating Committees assigned the SERC ATC Working Group the task of developing a common CBM and TRM Methodology for SERC. That group developed a document entitled SERC Guidelines for Transmission Capability Margins which was approved by the SERC Engineering Committee on December 8, 1999 The CBM and TRM methodologies employed by Virginia Power, which are described in this document, comply with the SERC guidelines.

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

- **Variations in generation dispatch:** Location and output of generation assumed in planning and pre-operational horizons may be vastly different from actual operating conditions. A margin may be necessary to account for generation sensitivity effects on Transmission Capability.

- **Allowances for parallel path "loop flow" impacts:** Each network element, to some extent, is subject to parallel path flows. These parallel path flows are the result of transmission service transactions that are not explicitly scheduled on the transmission system of a particular Transmission Provider. Since these flows are not scheduled on his system, a Transmission Provider may not be aware of or able to explicitly account for the impact of other parties' transactions on his own system. Therefore, maintenance of a reasonable quantity of "uncommitted" transmission capacity will help to assure that the reliability of the entire Interconnection is maintained. Note that proper coordination of system data between Transmission Providers and Control Areas should minimize the magnitude of this component**.**

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

- **Short-term Operator Response / System Response / Operating Reserves including Reserve-Sharing programs:** Following a contingency, system operators take immediate action, either individually or in concert with other operators, to maintain the reliability of the transmission system. Transmission capacity must remain available to allow for operator flexibility immediately following such a contingency. To maintain reliability, agreements between Control Areas exist to implement a quick and coordinated response following a transmission or generation contingency. These agreements include contracts among and between Reserve Sharing Groups (RSG). Operating reserve programs are designed to provide transmission operators with procedures needed to maintain reliability. Therefore, transmission resources needed to implement Operating Reserve Sharing Agreements for the period immediately following the contingency and before the reserves must be replaced is a TRM component.

  Operating reserves are additional capacity from either: a) generators that are on line, loaded to less than their maximum output, and available to serve customer demand immediately should a

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

How Virginia Power's TRM Values Are Determined

The most significant consideration in the determination of TRM for Virginia Power's imports is the variation in Virginia Power's generation dispatch (the first consideration listed in the SERC document). The TTCs for imports are first determined by assuming the outage of large units. The MUST program developed by Power Technologies, Inc. is then used to determine the import generation dispatch that yields the lowest TTC for a given interface. The difference in calculated TTCs between the "nominal" and "worst-case" generation dispatches is the generation dispatch component of TRM for that interface. The TRM components based on this method are calculated by off-line power flow studies using static models that may not represent actual system conditions during the period that these components are applied. Presently, there is no way to recalculate these components of TRM in real-time based on system conditions represented in on-line models.

Another significant consideration in the determination of Virginia Power's TRM is the effects of simultaneous transfers and parallel path flows on TTCs (the second and third considerations listed in the SERC document). For Virginia Power imports, the TTC reduction due to simultaneous transfers and parallel flows is generally less than the TTC reduction due to generation dispatch variation, and therefore is ignored. However, for Virginia Power exports, the effects of simultaneous transfers and parallel path flows can be significant. Based on calculations of various simultaneous transfers that may lower Virginia Power's TTCs, a rule-of-thumb has been adopted that establishes the value of the simultaneous transfer component of TRM on any interface to be 200 MW. As long as the generation dispatch component of TRM is greater than or equal to 200 MW, the simultaneous transfer component is transparent, and the generation dispatch component is used as the base value of TRM. If the generation component is less than 200 MW, the simultaneous transfer component establishes a minimum base value of TRM unless the sum of the tie-line limits is less than the calculated FCTTC of a path. In that case, the TTC is set at the tie-line limits and the base value of TRM is set to zero.

Another component of TRM that is applied to each interface is a reliability margin to allocate bundled transmission service that is part of the "grandfathered" emergency energy agreements between Virginia Power and each interconnected neighboring control area, with the exception of PJM. This addresses the Short Term Operator Response/System Response/Operating Reserves including Reserve Sharing programs (the fourth consideration listed in the SERC document.) For the VAP-CPLE interface, the value of this component is 450 MW in both directions. For the VAP-AEP and VAP-AP interfaces; the value is 100 MW in both directions. This reliability component of TRM is added to the base TRM of each interface.

To account for the effects of short-term versus long-term time frames on the level of uncertainty associated with TTC and ATC calculations, rules-of-thumb have been established that specify the appropriate values for the “a” and “b” multipliers for TRM in the planning and operating horizons (see the Equations for Calculating ATC on page 11). These rules ensure that TRM is reduced in the operating horizon since there is less uncertainty in the TTC and ATC calculations for this period. For all interfaces, the “a” factors are set to 1 so that RATC in the planning horizon (with no reservations in effect) equals NATC (with no reservations in effect). In the operating horizon, each interface whose base TRM is established by the simultaneous transfer component (200 MW) will have its “b” factor set at the appropriate value between zero and one to preserve 100 MW of base TRM plus the reliability component for that interface. For interfaces whose base TRM is established by the generation dispatch component, the “b” factors are set so that RATC in the operating horizon (with no schedules in effect) is 200 MW greater than RATC in the planning horizon (with no reservations in effect). For interfaces whose base TRM has been set to zero, the “b” factors default to unity.

CBM Calculation and Allocation

The methodology that each SERC LSE (including the native load of the host Transmission Provider) uses to derive their requirements for requesting CBM from SERC Transmission Providers must be documented and consistent with published planning criteria. A CBM request is considered consistent with published planning criteria if the same components that comprise the CBM are also addressed in the planning criteria. The methodology used to determine and apply CBM does not have to involve the same mechanics, as the planning process, but the same uncertainties must be considered and any simplifying assumptions explained.

The Generation Reserve Requirement that the SERC LSEs use can be determined via either deterministic or probabilistic methods.

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

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

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

1. The amount of additional external generating capacity necessary to achieve a target reliability level (e.g., 0.1 day / year loss of load expectation) must be determined.
2. The total amount of transmission transfer capability necessary to import the external generating reserve requirement must be determined from the amount of required external generating capacity (less the TRM component for operating reserves).

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

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

Regardless of the process used, the Transmission Provider must ensure and the SERC ATCWG must agree that:

a) The method used to arrive at the amount of external generation needed is consistent with applicable reliability criteria.
b) If the total transmission capacity reserved as CBM on all interfaces exceeds the external generation reserve requirement (less the TRM component for operating reserves), it is reasonable and justified.
c) The allocation of the total CBM to individual interfaces or source points is consistent with available external generation resources, known transmission limitations, and historical transfer patterns during actual emergency generating capacity deficiency events.

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

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

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

How Virginia Power's CBM Proxies are Determined

Virginia Power uses a deterministic methodology based on the loss of its largest plant for determining CBM. In the case of the Virginia Power transmission system, the worst generation emergency is the loss of the North Anna nuclear plant. Loss of this plant would result in an instantaneous generation deficiency of 1,800 MW. Since Virginia Power directly connects with four other Control Areas and since replacement generation could flow across any or all of our interfaces with these four Control Areas, Virginia Power has established a generation reserve transmission margin requirement for each interface equal to ¼of the worst case loss of generation. This equates to 450 MW on each interface in the import direction.

For a given interface, the required margin consists of the reliability component of TRM for that interface plus a CBM proxy. The CBM proxy is derived by subtracting the reliability component of TRM from the total requirement of 450 MW per interface. For example, the reliability component of TRM for the AEP-VAP interface is 100 MW; therefore, the CBM proxy for that interface is 450 minus 100 = 350 MW. Similarly, the CBM proxies for the CPLE-VAP, AP-VAP, and PJM-VAP interfaces are 0 MW, 350 MW, and 450 MW respectively.

Each CBM proxy is represented on OASIS as a firm reservation of transmission service. These reservations are offered for re-sale as non-firm transmission service and are subject to all existing provisions of the Virginia Power Open Access Transmission Tariff. The reason that proxies are used instead of actual CBM values is to meet the intent of the FERC order of July 28, 1999 in a timely manner without having to modify software. The OASIS backend processes used by Virginia Power to calculate and update OASIS postings cannot be readily modified to automatically calculate and update CBM as a special case of non-firm ATC. While the SERC guidelines do not specifically address CBM proxies, the use of these proxies allows CBM which is set aside for emergency use to be resold as non-firm transmission service as required by FERC.

Since all unaffiliated LSEs within the Virginia Power Control Area purchase all Ancillary Services from the Control Area, there is no need for any of them to need direct access to the generation reserve component of transmission margin represented by the CBM proxies. In situations where Virginia Power may have to import reserves due to a generation deficiency, the LSEs would benefit indirectly from these margins if Virginia Power had to rely on them to meet its ancillary service obligations to the LSEs. In a

generation emergency, the CBM proxies would be available for importing power as soon as any non-firm transactions scheduled against them could be curtailed.

Equations for Calculating ATC

The following is reproduced verbatim from the NERC document entitled "Available Transfer Capability Definitions and Determination"

Mathematically, NATC can be expressed as:

NATC = TTC - TRM - Non-recallable Reserved Transmission Service (including CBM)

Mathematically, RATC can be expressed as:

a) Planning Horizon

RATC = TTC
- a(TRM)
- Recallable Reserved Transmission Service
- Non-recallable Reserved Transmission Service (including CBM)

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

Mathematically, RATC can be expressed as:

a) Operating Horizon

RATC = TTC
- b(TRM)
- Recallable Scheduled Transmission Service
- Non-recallable Scheduled Transmission Service (including CBM)

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

Entergy

CBM/TRM Need and Methodology Statements

November 9, 1998
Revised: March 15, 2000

Entergy Reserve Margin Determination Needs and Methodology Statement

Transmission Reliability Margin (TRM)

In an effort to quantify "uncertainties" in system conditions, Entergy uses a Base-Load Adder (BLA) for determination of TRM on each interface posted on Entergy's OASIS. TTC/ATC is calculated using predictions of system conditions. These predictions include: load levels and the distribution of that load around the more than 1700 substations in Entergy's system, the mix of generation planned to meet that load, and loop flows associated with external energy schedules. While prediction of the impact on TTC of each of these phenomena is difficult to quantify, the end result is a difference between the predicted loading on transmission facilities and the actual loading on these facilities in the operating horizon.

Typically, ATC is determined based on the worst-case contingency element / limiting element pair. The worst-case contingency, when opened, will load an electrically adjacent element to 100% of its rating at a given transfer level. The transfer level at which this just occurs is determined to be the transfer capability for the studied path.

As a surrogate for direct quantification of each of the above "uncertainties", Entergy assumes that flow on the contingency element is higher than what models used to simulate the power system predict. The Base-Load Adder (BLA) for each contingency element will be a percent of the original predicted loading. The difference between transfer capability determined at the adjusted loading and the transfer capability determined at original predicted loading will be designated as TRM. This TRM would be decremented from FIRM ATC ONLY, allowing TRM to be sold as non-firm service.

The BLA used in the determination of TRM would increase with time. A BLA used to determine TRM for a year into the future would be larger than the BLA used in determination of TRM for a few days into the future. Predictions of contingency element loading are compared to actual, real-time loading on those facilities to set the BLA percentages. This allows the BLA to be adjusted to appropriate levels with actual data that can be tracked. BLA levels as of March 9, 2000 are as follows:

Horizon	Base BLA	Increase
Day 2 - Day 31	10%	0.5% per day
Month 2 - Month 13	35%	3% per month
Beyond Month 13	65%	5% per year

Example:

Assume transfer studies completed on March 1 for the time period May 1 determine that the ATC from Entergy to company X is 1000MW. Assume that line AB was identified as the worst-case contingency and that line AB was loaded to 500MW in the base case used to determine the ATC. A BLA of 35% would assume that the facility would actually be carrying 675MW on May 1 as opposed to the 500MW predicted in March. Assuming that line AB was actually loaded to 675MW, the ATC between Entergy and Company X would be less, for this example, 800MW. TRM would be set at 1000MW-800MW or 200MW for the Entergy to Company X path. Postings completed on March 1 would include a 200MW reduction in firm ATC.

On April 1, the study is repeated. The same ATC is predicted and the flow on line AB is still predicted to be 500MW. Since time has passed, and more information is known, the BLA used is 25%. The adjusted flow on line AB would then be 625MW. ATC based on a line AB flow of 625MW would be, for example, 920MW. TRM would be set at 80MW and postings completed on April 1 would include an 80MW reduction in firm ATC.

Capacity Benefit Margin (CBM)

Entergy's CBM practices and the MW allocation of the total CBM are posted on Entergy's OASIS.