December 20, 2013

BY ELECTRONIC FILING

Ms. Kimberly D. Bose, Secretary
Mr. Nathaniel J. Davis, Sr., Deputy Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: Amendment to Attachment C to the Southern Companies’ OATT
Docket No. ER14-__________________

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act and Part 35 of the Federal Energy Regulatory Commission’s (“Commission” or “FERC”) regulations, Southern Company Services, Inc. (“SCS”), as agent for Alabama Power Company (“Alabama Power”), Georgia Power Company, Gulf Power Company, and Mississippi Power Company (collectively, “Southern Companies”), hereby tenders to the Commission for filing an amendment to Attachment C (Methodology to Assess Available Transfer Capability) (“Attachment C”) of Southern Companies’ Open Access Transmission Tariff (Tariff Volume No. 5) (the “OATT”). The attached OATT amendment is being filed in Alabama Power’s database entitled:

OATT and Associated Service Agreements, Tariff Volume No. 5, Southern Companies OATT

I. Background and Description of Filing

On December 19, 2013, Entergy Arkansas, Inc., Entergy Gulf States Louisiana, L.L.C., Entergy Louisiana, LLC, Entergy Mississippi, LLC, Entergy New Orleans, Inc. and Entergy Texas (collectively, the “Entergy Operating Companies”) and the South Mississippi Electric

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1 The amendment is being filed in Alabama Power’s database because Alabama Power is the designated filer for Southern Companies’ OATT and related service agreements, including any amendments thereto. Georgia Power Company, Gulf Power Company and Mississippi Power Company each filed certificates of concurrence providing that they incorporated Southern Companies’ OATT and associated service agreements and all future amendments thereto. Because Georgia Power Company’s, Gulf Power Company’s and Mississippi Power Company’s certificates of concurrence incorporated all service agreements associated with the OATT, no filing will be made on behalf of those companies.
Power Association ("SMEPA") were integrated into the Midcontinent Independent System Operator, Inc. ("MISO"). Upon the integration, MISO became the Balancing Authority for the Entergy Operating Companies and SMEPA and, with respect to the determination of components of available transfer capability ("ATC") and related issues, it is more appropriate to refer to MISO in Southern Companies’ Attachment C. Therefore, Southern Companies are updating Attachment C to the OATT to delete the references to Entergy Operating Companies and its associated companies and SMEPA and to insert references to MISO. In addition, Southern Companies are taking this opportunity to update the web address where the ATC algorithms may be located.

Therefore, Southern Companies hereby submit the revised Attachment C to the OATT to incorporate the following changes: (i) update the web address where the subject ATC algorithm is located; (ii) replace references to Entergy Services, Inc. with references to MISO; and (iii) remove separate references to SMEPA. A redline showing the changes to Attachment C is attached to this transmittal letter.

II. Effective Date and Notice Requirement

Southern Companies respectfully request the Commission to make the attached revisions to the OATT effective as of December 19, 2013. This is appropriate because it is the date of integration of the Entergy Operating Companies into MISO and the date that the changes to Southern Companies’ methodology to assess available transfer capability began. Finally, given the number of proceedings that have been conducted at the state and federal levels related to Entergy Operating Companies being integrated into MISO, Southern Companies were waiting for more certainty prior to making and submitting these changes. Therefore, Southern Companies believe that good cause exists for a waiver of any of the Commission’s notice requirements set forth in 18 C.F.R. § 35.3 that the Commission believes are applicable.

III. Request for Waiver of Filing Requirements

Pursuant to 18 CFR § 35.13(a), Southern Companies are filing these changes to the provisions of Attachment C to their OATT and believe they have met the applicable filing requirements. However, to the extent necessary, Southern Companies respectfully request a waiver of any portion of the Commission’s regulations that are not satisfied by the enclosed information, including specifically any requirements set forth in 18 C.F.R. § 35.13(a) and (c)-(g).

IV. List of Documents

The following is a list of documents submitted with this filing:

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2 See 18 C.F.R. § 35.11; see also, e.g., In re Wyoming Colorado Intertie, LLC, 127 FERC ¶ 61,125 (2009) (granting waiver of filing requirements in Subpart B and C of Part 35, including section 35.13 except section 35.13(b) because the requirements were “not applicable” due to the nature of the rates charged).
1. Revised Attachment C to the OATT in RTF format with metadata attached;

2. A redline version of revised Attachment C to the OATT in PDF format for posting in eLibrary; and

3. A clean version of Attachment C to the OATT in PDF format for posting in eLibrary.

V. Posting

An electronic copy of this filing is being provided to each of Southern Companies’ customers under the OATT and will be posted on Southern Companies’ OASIS.

VI. Miscellaneous

As recognized by the Commission in Southern Company Services, Inc., 57 FERC ¶ 61,039 (1991), reh’g denied, 63 FERC ¶ 61,217 (1993), Southern Companies operate as an integrated transmission system. SCS is authorized to act as agent for Alabama Power, Georgia Power Company, Gulf Power Company, Mississippi Power Company and/or the individual operating companies and provides contract administration, data processing, accounting, and other services to Alabama Power, Georgia Power Company, Gulf Power Company, and Mississippi Power Company. If you have any questions or if additional information is required concerning this filing, it is requested that Kevin McNamee (205-226-8732) be contacted at the earliest possible date so that such information can be supplied expeditiously.

Sincerely,

/s/ Piyanka Ghosal
Piyanka Ghosal

OF COUNSEL:
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ATTACHMENT C

Methodology to Assess Available Transfer Capability

Available Transfer Capability Calculations

The Transmission Provider calculates Available Transfer Capability ("ATC") using mathematical algorithms that are compliant with the requirements of the current FERC approved version of North American Electric Reliability Corporation’s ("NERC") reliability standard regarding the Area Interchange Methodology.

ATC is automatically updated by the Transmission Provider’s OASIS each time: (i) Total Transfer Capability ("TTC") values are updated; and/or (ii) transmission service is purchased, scheduled, or redirected.\(^1\) ATC is calculated for each path, transmission service type and time period.

The Transmission Provider calculates ATC using the same mathematical algorithm for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon). The mathematical algorithm may be found at: https://www.weboasis.inati.com/woa/docs/OASIS/SOCO/TSRSOCDocs/ATC_algorithms.pdf

The basic ATC algorithm is as follows:

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\(^1\) The TTC and ATC values posted on the Transmission Provider’s OASIS are of the Transmission Provider’s ownership amount of the underlying transmission capacity.
ATC (Path, Service Type and Time Period specific) =
TTC (Total Transfer Capability)
- \( \sum \) ETC (Existing Transmission Commitments at equal or higher service code using the path\(^2\))
- CBM (Capacity Benefit Margin)
- TRM (Transmission Reliability Margin)
+ \( \sum \) Postbacks (Unscheduled transmission service commitments and redirected capacity at equal or higher service code linked back to the path)\(^3\)
+ \( \sum \) counterflows\(^4\)

The ATC values for the different transmission service types offered on OASIS are calculated using the same algorithm, but certain inputs may vary. These inputs are defined for each of the service types offered and consist of a service code and three logical “flags” (i.e., whether to apply TRM, whether to apply CBM, and whether to post back unused reserved capacity). Table A (ATC Algorithm Configuration) illustrates the configuration for each transmission service type offered on Transmission Provider’s OASIS.

Specific algorithms for calculating Firm and Non-Firm ATC are as follows:

- Firm ATC = TTC – ETC\(_F\) – CBM – TRM + Postbacks\(_F\) + counterflows\(_F\)
- Non-Firm ATC = TTC – ETC\(_F\) + ETC\(_N\) – CBM\(_S\) – TRM\(_U\) + Postbacks\(_{NF}\) + counterflows\(_{NF}\)

Where:

- TTC is the Total Transfer Capability of the ATC Path for that period.
- ETC\(_F\) is the sum of existing firm transmission commitments for the ATC Path during that period.

\(^2\) Transmission service types are assigned service codes for purposes of the ATC algorithm, and such service codes are set forth in Table A (ATC Algorithm Configuration). Confirmed reservations utilizing the same path and of equal or higher service code are considered in each calculation. For example, an ATC value is calculated for Monthly Firm Point-To-Point (“PTP”) Transmission Service for the path from a particular POR to SOCO by including confirmed reservations of service code 6 and above that utilize that path. Reservations utilizing a different path or of lower service code (e.g., service code 7) would not be included in the calculation.

\(^3\) Postbacks consist of unscheduled transmission service and redirected Transmission Service. Unscheduled transmission service commitments are considered in calculating ATC for hourly service. Confirmation of a request to redirect Transmission Service results in the reduction of ATC on the redirected (new) path and increase of ATC on the original path, at a service type with an equal or lower service code than the new redirected Transmission Service. For example, if the original Transmission Service was Monthly Firm PTP (service code 6) and the new redirected Transmission Service is Daily Firm PTP (service code 10), then ATC will be added back to the original path in the calculation of Daily Firm PTP (service code 10 and below), but not in the calculation of Monthly Firm PTP. At a minimum, redirected capacity is added back to all Hourly services on the original path.

\(^4\) Counterflows are the amount of scheduled megawatts (“MW”) associated with the Transmission Service Providers’ (“TSP”) customers’ transactions that will flow in the opposite direction on a path (resulting in a reliable reduction of flow on constrained facilities), that the TSP determines can effectively be used to increase ATC. It should be noted that counterflows associated with certain types of constraints (e.g., simultaneous transfer capability limits, voltage limits and stability limits) may not provide relief to constrained facilities required to enable a reliable increase in ATC values. The TSP only considers counterflows in the calculation of hourly (non-firm) ATC.
ETCN<sub>F</sub> is the sum of existing non-firm transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

CBM<sub>S</sub> is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM<sub>U</sub> is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity TSP during that period.

Postbacks<sub>F</sub> are changes to firm ATC due to a change in the use of transmission service for that period, as defined herein.

counterflows<sub>F</sub> are adjustments to firm ATC as determined by the Transmission Service Provider and specified herein.

Postbacks<sub>NF</sub> are changes to non-firm ATC due to a change in the use of transmission service for that period, as defined herein.

counterflows<sub>NF</sub> are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified herein.

### TABLE A

#### ATC Algorithm Configuration

<table>
<thead>
<tr>
<th>Time</th>
<th>Class</th>
<th>Transmission Service Type</th>
<th>Service Code</th>
<th>Apply TRM</th>
<th>Apply CBM</th>
<th>Postback Unscheduled Transmission Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yearly</td>
<td>Firm</td>
<td>Network</td>
<td>1</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Yearly</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>2</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Yearly</td>
<td>Firm</td>
<td>Recallable</td>
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<td>Y</td>
<td>Y</td>
<td>N</td>
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<tr>
<td>Yearly</td>
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<td>Conditional</td>
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<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Monthly</td>
<td>Firm</td>
<td>Network</td>
<td>5</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Monthly</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>6</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Weekly</td>
<td>Firm</td>
<td>Network</td>
<td>7</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Weekly</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>8</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Daily</td>
<td>Firm</td>
<td>Network</td>
<td>9</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Daily</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>10</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Daily</td>
<td>Secondary</td>
<td>Network</td>
<td>11</td>
<td>N</td>
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<td>N</td>
</tr>
<tr>
<td>Hourly</td>
<td>Secondary</td>
<td>Network</td>
<td>12</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Monthly</td>
<td>Non-Firm</td>
<td>Point-To-Point</td>
<td>13</td>
<td>N</td>
<td>N</td>
<td>N</td>
</tr>
<tr>
<td>Weekly</td>
<td>Non-Firm</td>
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<td>N</td>
</tr>
<tr>
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<td>N</td>
</tr>
<tr>
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<td>Point-To-Point</td>
<td>16</td>
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<td>Y</td>
</tr>
<tr>
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<td>Secondary</td>
<td>Point-To-Point</td>
<td>17</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
</tbody>
</table>
This process flow diagram illustrates the various steps through which a single ATC (based upon specific factors) is calculated. Similar ATC calculations are performed for each path, service type, and time period and will generally result in different ATC values specific to those factors.
**ATC Components**

The ATC components are calculated consistently in the operating and planning horizons to meet the zero to thirteen months posting requirements.

**Total Transfer Capability (“TTC”):** The Transmission Provider defines TTC, consistent with the “Glossary of Terms Used in NERC Reliability Standards” (updated April 20, 2010), as the “amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.” Transfer analysis conducted to determine TTC is performed consistent with the principles provided in “Transmission Transfer Capability – A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems” dated May, 1995 and in compliance with the requirements of the current FERC approved version of the NERC reliability standard regarding the Area Interchange Methodology. Further, transfer analysis is performed respecting all applicable System Operating Limits (SOL).

TTC values in the Southern Balancing Authority Area (“SBAA”)\(^5\) are determined on an “aggregated basis” in which the transmission facilities of transmission owners located within the SBAA (Dalton Utilities, Georgia Transmission Corporation, Municipal Electric Authority of Georgia, and the Transmission Provider) are treated as a combined electrical system in transfer analysis studies.

The Transmission Provider performs a simultaneous transfer analysis to determine TTC values for each of the five northern interfaces (i.e., Entergy Services, Inc., Midcontinent Independent System Operator, Inc. (“EntergyMISO”), Tennessee Valley Authority (“TVA”), Duke Power Company (“Duke”), South Carolina Public Service Authority (“Santee Cooper”), and South Carolina Electric and Gas Company (“SCE&G”)).\(^6\)

The Transmission Provider performs separate non-simultaneous analyses to determine TTC values for PowerSouth Energy Cooperative, South Mississippi Electric Power Association, and Peninsular Florida.\(^7\)

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\(^5\) “Southern Company Services, Inc. – Trans” is the Balancing Authority for Southern Companies’ reliability area.

\(^6\) Transmission Provider may also perform non-simultaneous analysis if more limiting system conditions arise on a particular interface and may utilize the lower of the simultaneous or the non-simultaneous TTC results if system conditions warrant.

\(^7\) The term “Peninsular Florida” refers to the portion of the State of Florida that contains the utilities and Balancing Authority Areas in the Florida Reliability Coordinating Council (“FRCC”).

The Transmission Provider uses load level forecasts corresponding with the actual load levels for the period under study. Monthly load levels correspond to historical peak load information for each month. Near-time load level forecasts are developed using a neural network application based upon weather data and load information obtained by the SCS Energy Management System in real-time. The Transmission Provider uses a generation dispatch order based upon information provided by the load-serving entities (“LSE”), which results in an economic dispatch of network resources to serve network loads. Planned outages are modeled as being out of service during the duration of the outage in TTC assessments of corresponding periods. Forced outages are modeled as being out of service during the duration of the anticipated repair. NERC SDX and SCS Equipment Outage Schedule databases are updated when equipment is returned to service so that subsequent TTC assessments reflect the equipment as being in service.

**Existing Transmission Commitments (“ETC”):** The Transmission Provider defines ETC as commitments for transmission service which exist at the time a transfer analysis is performed. Transmission service for network and native loads is represented in power flow analyses by modeling forecasted loads and serving them with an economic dispatch of the associated network resources. Firm PTP Transmission Service is represented in the power flow models with the specific source serving the specific sink.\(^8\) The modeling treatment is consistent whether the existing transmission service commitment is OATT service or non-OATT (native load or grandfathered) service. Rollover rights are evaluated as a continuation of service in the zero to thirteen months postings unless the renewal deadline has expired and the transmission customer has not elected to continue taking such service.

For each particular interface, service type, and time period, ATC is determined by subtracting the commitments on that interface from the respective TTC value in accordance with the algorithms shown above. Firm ATC calculations consider only firm commitments. Non-firm ATC considers both firm and non-firm commitments.

**Postbacks:** The Transmission Provider defines postbacks as capacity that is posted back on OASIS as additional ATC as a result of: (i) transmission customers not scheduling service; or (ii) transmission customers’ redirects of service to other paths.

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\(^8\) This modeling occurs to the extent the specific source is known and can be practically modeled by the Transmission Provider. PTP Transmission Service may not be modeled during periods when it is not expected to be scheduled; however, the right to schedule such service would be maintained.
• **Unscheduled Service:** Transmission service commitments that are not scheduled (wholly or partially) result in the unscheduled portions being posted back to OASIS in the form of non-firm ATC. For example, if the holder of 100 MW of Daily Firm service on a path schedules only 80 MW during an upcoming hour, the remaining 20 MW will be posted back as non-firm ATC on that path for that hour.

• **Short-term Redirect:** Firm PTP Transmission Customers may redirect their Transmission Service on a firm or non-firm basis, to any path where ATC is available.
  - If the redirect is to a path where firm Transmission Service is available, the firm ATC will be decremented on the new path and firm ATC will be released on the original path.
  - If the redirect is to a path where only non-firm Transmission Service is available, the non-firm ATC will be decremented on the new path; however, the Transmission Customer will reserve the right to return to the original path and firm ATC will not be released on the original path. Non-firm ATC will be released on the original path.

**Counterflows:** The Transmission Provider defines counterflows as the amount of scheduled megawatts associated with the TSP’s customers’ transactions that will flow in the opposite direction on a path (resulting in a reliable reduction of flow on constrained facilities), that the TSP determines can effectively be used to increase ATC. It should be noted that counterflows associated with certain types of constraints (e.g., simultaneous transfer capability limits, voltage limits and stability limits) may not provide relief to constrained facilities required to enable a reliable increase in ATC values. The TSP only considers counterflows in the calculation of hourly (non-firm) ATC.

**Transmission Reliability Margin (‘TRM’):**

A. **Definition of TRM.** The Transmission Provider defines TRM, consistent with NERC’s “Available Transfer Capability Definitions and Determination: A Framework for Determining Available Transfer Capabilities of the Interconnection Transmission Networks for a Commercially Viable Electricity Market” dated June, 1996, as the “amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.”

B. **Transmission Provider’s TRM calculation methodology.**

The SBAA has four primary interfaces with external utilities: TVA, VACAR, Peninsular Florida and EntergyMISO. The VACAR interface is composed of interconnections between the SBAA and Duke, SCE&G, and Santee Cooper. The
Duke, Peninsular Florida, TVA and Entergy MISO interfaces each have at least one 500 kV transmission line as part of the interconnection to the SBAA. For this reason, TRM is allocated among certain ATC Paths on the TVA, Duke, Peninsular Florida and Entergy MISO interfaces. TRM on ATC Paths at other interfaces, such as SCE&G and Santee Cooper, will be zero MW.

The methodology to determine Transmission Provider’s TRM utilizes the current peak-load period dynamics model for transmission planning studies. Representation for the systems external to the SBAA comes from the SERC Reliability Corporation (“SERC”) Dynamic Studies Group (used to model the systems of the SERC members) and a dynamic reduction of a NERC MMWG dynamics case for those utilities outside of the SERC region. Transmission Provider’s methodology uses the inertial response of the interfaces to the loss of a single selected generating unit within the SBAA. Analysis is performed by switching off a single unit with generating capacity greater than 500 MW in order to assess the inrush requirement at each interface for that particular unit. Siemens PSS/E is used to examine the generator governor’s response for all the generators in the Eastern Interconnection modeled thirty seconds after the loss of the major unit. Thirty seconds was selected to allow the generator governors time to settle out at the new operating point. Analyses are performed to determine the generation response from utilities interconnected with the SBAA. The amount of this response multiplied by the MW of lost generation forms the basis of total TRM.

The largest MW response of each interface (for the outage of units under consideration) is selected and summed. The TRM allocation for each interface is found by dividing the largest response for the interface by the sum and multiplying this value by total TRM.

C. Databases used in TRM assessments. The following databases are utilized in the TRM assessment:
   - Southern Companies’ Dynamics Database for Transmission Planning Models
   - SERC Dynamics Study Group – Dynamics Database
   - NERC MMWG Dynamics Model

   TRM values are maintained in the OASIS database.

D. Conditions under which the Transmission Provider uses TRM. The Transmission Provider reserves TRM only to calculate firm ATC for imports and such capacity is made available to the market on a non-firm basis.
**Capacity Benefit Margin ("CBM"):**

1. **CBM practice for both the operating and planning horizons.**

   A. **Entity that performs the resource adequacy analysis for CBM determination.** Each LSE is responsible to make its own CBM determination. For the Transmission Provider, resource adequacy analyses for determination of CBM are conducted by Southern Company Services, Inc.’s ("SCS") Resource Planning group as agent for the Transmission Provider in its provision of electric service to its franchised service territories.

   B. **Methodology used to perform generation reliability assessments.** The Transmission Provider has established a target reserve margin for generation adequacy planning which is the point where total reliability costs and capacity costs are minimized. Resource adequacy is regulated by the Transmission Provider’s respective State commissions. In order to maintain this minimum cost point, some level of CBM reservation is required. Probabilistic analyses using Monte Carlo techniques and historical data are conducted to determine the optimum reserve margin based on different levels of CBM. The resource adequacy analyses utilize CBM in a similar manner to that of firm territorial capacity resources in the determination of the optimum (overall least cost) reserve margin. As such, the methodology utilized to determine the quantity of CBM set-aside is (1) consistent with the Transmission Provider’s methodology for assessing resource adequacy, and (2) is an integral part of such target reserve margin/resource adequacy determination.

   The Monte Carlo method considers generating unit forced outages and de-rates 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 are inputs to the model. It is anticipated that this assessment will be conducted at least every three years and reviewed annually, and may be performed more frequently if system conditions or assumptions change significantly.

   C. **Explanation of whether the assessment reflects a specific regional practice.** The evaluation methodology does not reflect any specific regional practice.

   D. **Assumptions used in the resource adequacy assessment.** The evaluation methodology contains many assumptions including: Load Forecast Error (LFE) (discussed below), weather uncertainty, machine outage rates (forced and planned) and repair durations, availability of conventional hydro resources, availability of tie assistance, and other factors.
LFE is determined from statistical analysis of historical forecasts versus actual loads. The resultant probability distribution represents the load forecast uncertainty.

The effect of weather on system load is calculated using trend analyses of historical temperature versus load data for each year evaluated, typically incorporating the data from numerous preceding years. Results from this analysis are input to the model along with the target peak demand hourly system loads for each of the years.

E. Basis for the selection of paths on which CBM is set aside. Paths for CBM are chosen across interfaces with neighboring Balancing Authority Areas shown in SERC published data as having sufficient excess generation resources. Total import capability from tie lines during peak hours is a function of both tie line limits and the projected 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. Outside the computer model, the relative availability of generation and transmission capability is considered in order to allocate the desired CBM across the various interfaces.

2. Additional CBM Information.

A. Definition of CBM. CBM is that amount of firm, import TTC on interfaces with adjacent Balancing Authority Areas reserved by LSEs to ensure access to generation resources from interconnected systems to meet generation reliability requirements of LSEs' native/network load customers.

B. List of databases used in calculations to determine CBM. Inputs to the resource adequacy model are developed from various sources and are consistent with those used to develop the Transmission Provider’s integrated resource plan. A listing of the primary databases follows:

<table>
<thead>
<tr>
<th>Database Name</th>
<th>Data Utilized</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southern Company System Planning Database</td>
<td>Machine data (e.g., min/max output, heat rate, delivered fuel cost, startup and VOM costs, emissions cost, planned outages, etc.)</td>
</tr>
<tr>
<td>NERC’s GADS database</td>
<td>Historical forced outage information</td>
</tr>
<tr>
<td>Platts Energy Market Data</td>
<td>Historical pricing for energy strips</td>
</tr>
<tr>
<td>SC Marketing Services Barrons Reports</td>
<td>Load forecasting data</td>
</tr>
<tr>
<td>Southern Company Historical Load/Temp Data</td>
<td>Historical load and temperature data</td>
</tr>
</tbody>
</table>
C. Double-counting of contingency outages when performing CBM, TTC, and TRM calculations. TRM is the amount of TTC necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. CBM is that amount of firm, import TTC on interfaces with adjacent Balancing Authority Areas reserved by LSEs to ensure access to generation resources from interconnected systems to meet generation reliability requirements of LSEs’ native/network load customers. In addition, neither TRM nor CBM are used to calculate TTC. Therefore, there is no double-counting of contingency outages when performing CBM, TTC and TRM calculations. Analysis software for the determination of CBM utilizes a transport model instead of a transmission model; contingencies are not explicitly modeled.

3. Procedures for allowing the use of CBM during emergencies.

When an Emergency (as defined below) occurs, CBM may be called upon by the LSE that reserved the CBM to import power on a firm basis into the SBAA to ensure the continued reliability of service to the LSE’s native/network load customers.

A. What constitutes an Emergency. An Emergency exists when the resources of an LSE are projected to be insufficient to serve its native/network load customers. Such Emergency meets the conditions established by NERC EEA2.

B. Entities that are permitted to use CBM during an emergency.

(i) Eligibility for use of CBM. CBM is available for the Transmission Provider and Network Customers taking Network Integration Transmission Service under the Tariff to serve their respective native/network load. For such Network Customers who only serve a portion of their load under Part III of the Tariff, any CBM reserved shall be limited to that reasonably needed for the Network Customer’s load served under Part III of the Tariff.

(ii) Reservation Of CBM. Each eligible LSE is responsible for reserving its own CBM requirements. To make such a reservation, the LSE must submit a request to the Transmission Provider’s transmission function setting forth the following information: (a) the amount of CBM desired on each particular interface; (b) a description of the methodology used to determine its CBM; and (c) the basis for reserving CBM on the requested paths. The Transmission Provider’s 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, including higher queued long-term firm requests under the Tariff. The Transmission Provider’s transmission function reserves the right to deny CBM requests that appear unreasonable or disproportionate given the amount of native/network load service being provided to that LSE by the
Transmission Provider’s transmission system, with Network Customer’s taking Network Integration Transmission Service under the Tariff limited to that reasonably needed for the amount of load served under Part III of the Tariff.

(iii) **Use of CBM.** CBM may be used during an Emergency by the LSE who reserved it to import power on a firm basis into the SBAA to ensure the continued reliability of service to native/network load customers.

(iv) **Availability of Reserved CBM Capacity to Other Customers.** Transmission capacity reserved for CBM will be made available on a non-firm basis when CBM is not needed to maintain system reliability during periods of projected resource deficiencies.

C. **Procedures which must be followed by the Transmission Provider and other eligible LSEs when they need to access CBM.** The procedures to be followed in using reserved CBM are outlined below:

(i) The LSE will make a reservation on OASIS for Network Integration Transmission Service (Type = Network; Class = Firm; Increment = Daily, Weekly, Monthly, Yearly) on a specific path on which it has reserved CBM.

(ii) The LSE will note in the comment section of the network service template that the reservation is for the use of CBM capacity on the path.

The Transmission Provider’s transmission function will evaluate the transmission service request and provide the requested CBM transmission service on a firm basis if it is reasonable and sufficient transmission capacity is available on the path.

**Coordination of ATC Calculations with Neighboring Systems**

The Transmission Provider participates with the SERC Intra-Regional Near Term Study Group to develop quarterly OASIS power flow cases for the upcoming five quarters. These cases are derived from the SERC Intra-Regional Long Term Study Group’s “Yearly” base cases, which are an aggregation of each SERC participant’s transmission planning model for their respective systems. The SERC OASIS power flow cases incorporate the system topology, facility ratings, generation dispatch, system demands (load forecasts), and transmission uses provided by each SERC participant.

The Transmission Provider further coordinates with its Tier 1 neighbors to receive inputs on a monthly basis to update the quarterly SERC OASIS power flow cases into thirteen monthly power flow cases. These monthly inputs include updates to system parameters associated with each individual month. The Transmission Provider adds to these inputs the specific firm transmission service commitments that are expected to be scheduled to create the SBAA monthly power flow cases which are used for monthly TTC assessments.
The Transmission Provider provides continuous access to transmission service requests and commitments through its OASIS. The Transmission Provider participates with the SERC Intra-Regional Near Term Study Group to provide monthly coordination of all confirmed firm monthly and yearly transmission service commitments. The Transmission Provider provides hourly updates of outage information through the NERC SDX. The Transmission Provider issues its transfer capability methodology to adjacent Reliability Coordinators, Transmission Operators, and other entities that indicate a reliability-related need in accordance with NERC requirements.

The Transmission Provider also participates in the Florida-Southern Coordinating Group to develop coordinated transfer capability values between the SBAA and the FRCC. The joint studies and the resulting transfer capabilities are provided to the Reliability Coordinators and to participating Transmission Providers for use in their respective OASIS postings.
ATTACHMENT C

Methodology to Assess Available Transfer Capability

Available Transfer Capability Calculations

The Transmission Provider calculates Available Transfer Capability ("ATC") using mathematical algorithms that are compliant with the requirements of the current FERC approved version of North American Electric Reliability Corporation’s ("NERC") reliability standard regarding the Area Interchange Methodology.

ATC is automatically updated by the Transmission Provider’s OASIS each time: (i) Total Transfer Capability ("TTC") values are updated; and/or (ii) transmission service is purchased, scheduled, or redirected.¹ ATC is calculated for each path, transmission service type and time period.

The Transmission Provider calculates ATC using the same mathematical algorithm for the scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon). The mathematical algorithm may be found at: https://www.oasis.ati.com/woa/docs/SOCO/SOCOdocs/ATC_algorithms.pdf

The basic ATC algorithm is as follows:

¹ The TTC and ATC values posted on the Transmission Provider’s OASIS are of the Transmission Provider’s ownership amount of the underlying transmission capacity.
ATC (Path, Service Type and Time Period specific) =
TTC (Total Transfer Capability)
- \( \sum \) ETC (Existing Transmission Commitments at equal or higher service code using the path\(^2\))
- CBM (Capacity Benefit Margin)
- TRM (Transmission Reliability Margin)
+ \( \sum \) Postbacks (Unscheduled transmission service commitments and redirected capacity at equal or higher service code linked back to the path)\(^3\)
+ \( \sum \) counterflows\(^4\)

The ATC values for the different transmission service types offered on OASIS are calculated using the same algorithm, but certain inputs may vary. These inputs are defined for each of the service types offered and consist of a service code and three logical “flags” (i.e., whether to apply TRM, whether to apply CBM, and whether to post back unused reserved capacity). Table A (ATC Algorithm Configuration) illustrates the configuration for each transmission service type offered on Transmission Provider’s OASIS.

Specific algorithms for calculating Firm and Non-Firm ATC are as follows:

- Firm ATC = TTC – ETC\(_F\) – CBM – TRM + Postbacks\(_F\) + counterflows\(_F\)
- Non-Firm ATC = TTC – ETC\(_F\) - ETC\(_N\) – CBM\(_S\) – TRM\(_U\) + Postbacks\(_N\) + counterflows\(_N\)

Where:

\( \text{TTC} \) is the Total Transfer Capability of the ATC Path for that period.
\( \text{ETC}_F \) is the sum of existing firm transmission commitments for the ATC Path during that period.

\(^2\) Transmission service types are assigned service codes for purposes of the ATC algorithm, and such service codes are set forth in Table A (ATC Algorithm Configuration). Confirmed reservations utilizing the same path and of equal or higher service code are considered in each calculation. For example, an ATC value is calculated for Monthly Firm Point-To-Point (“PTP”) Transmission Service for the path from a particular POR to SOCO by including confirmed reservations of service code 6 and above that utilize that path. Reservations utilizing a different path or of lower service code (e.g., service code 7) would not be included in the calculation.

\(^3\) Postbacks consist of unscheduled transmission service and redirected Transmission Service. Unscheduled transmission service commitments are considered in calculating ATC for hourly service. Confirmation of a request to redirect Transmission Service results in the reduction of ATC on the redirected (new) path and increase of ATC on the original path, at a service type with an equal or lower service code than the new redirected Transmission Service. For example, if the original Transmission Service was Monthly Firm PTP (service code 6) and the new redirected Transmission Service is Daily Firm PTP (service code 10), then ATC will be added back to the original path in the calculation of Daily Firm PTP (service code 10 and below), but not in the calculation of Monthly Firm PTP. At a minimum, redirected capacity is added back to all Hourly services on the original path.

\(^4\) Counterflows are the amount of scheduled megawatts (“MW”) associated with the Transmission Service Providers’ (“TSP”) customers’ transactions that will flow in the opposite direction on a path (resulting in a reliable reduction of flow on constrained facilities), that the TSP determines can effectively be used to increase ATC. It should be noted that counterflows associated with certain types of constraints (e.g., simultaneous transfer capability limits, voltage limits and stability limits) may not provide relief to constrained facilities required to enable a reliable increase in ATC values. The TSP only considers counterflows in the calculation of hourly (non-firm) ATC.
ETCN_F is the sum of existing non-firm transmission commitments for the ATC Path during that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled without a separate reservation during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity TSP during that period.

Postbacks_F are changes to firm ATC due to a change in the use of transmission service for that period, as defined herein.

Counterflows_F are adjustments to firm ATC as determined by the Transmission Service Provider and specified herein.

Postbacks_NF are changes to non-firm ATC due to a change in the use of transmission service for that period, as defined herein.

Counterflows_NF are adjustments to non-firm ATC as determined by the Transmission Service Provider and specified herein.

### TABLE A

**ATC Algorithm Configuration**

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Class</th>
<th>Transmission Service Type</th>
<th>Service Code</th>
<th>Apply TRM</th>
<th>Apply CBM</th>
<th>Postback Unscheduled Transmission Service</th>
</tr>
</thead>
<tbody>
<tr>
<td>Yearly</td>
<td>Firm</td>
<td>Network</td>
<td>1</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Yearly</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>2</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Yearly</td>
<td>Firm</td>
<td>Recallable</td>
<td>3</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Yearly</td>
<td>Firm</td>
<td>Conditional</td>
<td>4</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Monthly</td>
<td>Firm</td>
<td>Network</td>
<td>5</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Monthly</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>6</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Weekly</td>
<td>Firm</td>
<td>Network</td>
<td>7</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Weekly</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>8</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Daily</td>
<td>Firm</td>
<td>Network</td>
<td>9</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Daily</td>
<td>Firm</td>
<td>Point-To-Point</td>
<td>10</td>
<td>Y</td>
<td>Y</td>
<td>N</td>
</tr>
<tr>
<td>Daily</td>
<td>Secondary</td>
<td>Network</td>
<td>11</td>
<td>N</td>
<td>N</td>
<td>N</td>
</tr>
<tr>
<td>Hourly</td>
<td>Secondary</td>
<td>Network</td>
<td>12</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Monthly</td>
<td>Non-Firm</td>
<td>Point-To-Point</td>
<td>13</td>
<td>N</td>
<td>N</td>
<td>N</td>
</tr>
<tr>
<td>Weekly</td>
<td>Non-Firm</td>
<td>Point-To-Point</td>
<td>14</td>
<td>N</td>
<td>N</td>
<td>N</td>
</tr>
<tr>
<td>Daily</td>
<td>Non-Firm</td>
<td>Point-To-Point</td>
<td>15</td>
<td>N</td>
<td>N</td>
<td>N</td>
</tr>
<tr>
<td>Hourly</td>
<td>Non-Firm</td>
<td>Point-To-Point</td>
<td>16</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
<tr>
<td>Hourly</td>
<td>Secondary</td>
<td>Point-To-Point</td>
<td>17</td>
<td>N</td>
<td>N</td>
<td>Y</td>
</tr>
</tbody>
</table>
This process flow diagram illustrates the various steps through which a single ATC (based upon specific factors) is calculated. Similar ATC calculations are performed for each path, service type, and time period and will generally result in different ATC values specific to those factors.
ATC Components

The ATC components are calculated consistently in the operating and planning horizons to meet the zero to thirteen months posting requirements.

Total Transfer Capability (“TTC”): The Transmission Provider defines TTC, consistent with the “Glossary of Terms Used in NERC Reliability Standards” (updated April 20, 2010), as the “amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.” Transfer analysis conducted to determine TTC is performed consistent with the principles provided in “Transmission Transfer Capability – A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems” dated May, 1995 and in compliance with the requirements of the current FERC approved version of the NERC reliability standard regarding the Area Interchange Methodology. Further, transfer analysis is performed respecting all applicable System Operating Limits (SOL).

TTC values in the Southern Balancing Authority Area (“SBAA”)\(^5\) are determined on an “aggregated basis” in which the transmission facilities of transmission owners located within the SBAA (Dalton Utilities, Georgia Transmission Corporation, Municipal Electric Authority of Georgia, and the Transmission Provider) are treated as a combined electrical system in transfer analysis studies.

The Transmission Provider performs a simultaneous transfer analysis to determine TTC values for each of the five northern interfaces (i.e., Midcontinent Independent System Operator, Inc. (“MISO”), Tennessee Valley Authority (“TVA”), Duke Power Company (“Duke”), South Carolina Public Service Authority (“Santee Cooper”), and South Carolina Electric and Gas Company (“SCE&G”)).\(^6\)

The Transmission Provider performs separate non-simultaneous analyses to determine TTC values for PowerSouth Energy Cooperative, and Peninsular Florida.\(^7\)

\(^5\) “Southern Company Services, Inc. – Trans” is the Balancing Authority for Southern Companies’ reliability area.

\(^6\) Transmission Provider may also perform non-simultaneous analysis if more limiting system conditions arise on a particular interface and may utilize the lower of the simultaneous or the non-simultaneous TTC results if system conditions warrant.

\(^7\) The term “Peninsular Florida” refers to the portion of the State of Florida that contains the utilities and Balancing Authority Areas in the Florida Reliability Coordinating Council (“FRCC”).

The Transmission Provider uses load level forecasts corresponding with the actual load levels for the period under study. Monthly load levels correspond to historical peak load information for each month. Near-time load level forecasts are developed using a neural network application based upon weather data and load information obtained by the SCS Energy Management System in real-time. The Transmission Provider uses a generation dispatch order based upon information provided by the load-serving entities (“LSE”), which results in an economic dispatch of network resources to serve network loads. Planned outages are modeled as being out of service during the duration of the outage in TTC assessments of corresponding periods. Forced outages are modeled as being out of service during the duration of the anticipated repair. NERC SDX and SCS Equipment Outage Schedule databases are updated when equipment is returned to service so that subsequent TTC assessments reflect the equipment as being in service.

**Existing Transmission Commitments (“ETC”):** The Transmission Provider defines ETC as commitments for transmission service which exist at the time a transfer analysis is performed. Transmission service for network and native loads is represented in power flow analyses by modeling forecasted loads and serving them with an economic dispatch of the associated network resources. Firm PTP Transmission Service is represented in the power flow models with the specific source serving the specific sink.\(^8\) The modeling treatment is consistent whether the existing transmission service commitment is OATT service or non-OATT (native load or grandfathered) service. Rollover rights are evaluated as a continuation of service in the zero to thirteen months postings unless the renewal deadline has expired and the transmission customer has not elected to continue taking such service.

For each particular interface, service type, and time period, ATC is determined by subtracting the commitments on that interface from the respective TTC value in accordance with the algorithms shown above. Firm ATC calculations consider only firm commitments. Non-firm ATC considers both firm and non-firm commitments.

**Postbacks:** The Transmission Provider defines postbacks as capacity that is posted back on OASIS as additional ATC as a result of: (i) transmission customers not scheduling service; or (ii) transmission customers’ redirects of service to other paths.

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\(^8\) This modeling occurs to the extent the specific source is known and can be practically modeled by the Transmission Provider. PTP Transmission Service may not be modeled during periods when it is not expected to be scheduled; however, the right to schedule such service would be maintained.
• **Unscheduled Service:** Transmission service commitments that are not scheduled (wholly or partially) result in the unscheduled portions being posted back to OASIS in the form of non-firm ATC. For example, if the holder of 100 MW of Daily Firm service on a path schedules only 80 MW during an upcoming hour, the remaining 20 MW will be posted back as non-firm ATC on that path for that hour.

• **Short-term Redirect:** Firm PTP Transmission Customers may redirect their Transmission Service on a firm or non-firm basis, to any path where ATC is available.
  - If the redirect is to a path where firm Transmission Service is available, the firm ATC will be decremented on the new path and firm ATC will be released on the original path.
  - If the redirect is to a path where only non-firm Transmission Service is available, the non-firm ATC will be decremented on the new path; however, the Transmission Customer will reserve the right to return to the original path and firm ATC will not be released on the original path. Non-firm ATC will be released on the original path.

**Counterflows:** The Transmission Provider defines counterflows as the amount of scheduled megawatts associated with the TSP’s customers’ transactions that will flow in the opposite direction on a path (resulting in a reliable reduction of flow on constrained facilities), that the TSP determines can effectively be used to increase ATC. It should be noted that counterflows associated with certain types of constraints (e.g., simultaneous transfer capability limits, voltage limits and stability limits) may not provide relief to constrained facilities required to enable a reliable increase in ATC values. The TSP only considers counterflows in the calculation of hourly (non-firm) ATC.

**Transmission Reliability Margin (‘TRM’):**

A. **Definition of TRM.** The Transmission Provider defines TRM, consistent with NERC’s “Available Transfer Capability Definitions and Determination: A Framework for Determining Available Transfer Capabilities of the Interconnection Transmission Networks for a Commercially Viable Electricity Market” dated June, 1996, as the “amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.”

B. **Transmission Provider’s TRM calculation methodology.**

The SBAA has four primary interfaces with external utilities: TVA, VACAR, Peninsular Florida and MISO. The VACAR interface is composed of interconnections between the SBAA and Duke, SCE&G, and Santee Cooper. The
Duke, Peninsular Florida, TVA and MISO interfaces each have at least one 500 kV transmission line as part of the interconnection to the SBAA. For this reason, TRM is allocated among certain ATC Paths on the TVA, Duke, Peninsular Florida and MISO interfaces. TRM on ATC Paths at other interfaces, such as SCE&G and Santee Cooper, will be zero MW.

The methodology to determine Transmission Provider’s TRM utilizes the current peak-load period dynamics model for transmission planning studies. Representation for the systems external to the SBAA comes from the SERC Reliability Corporation (“SERC”) Dynamic Studies Group (used to model the systems of the SERC members) and a dynamic reduction of a NERC MMWG dynamics case for those utilities outside of the SERC region. Transmission Provider’s methodology uses the inertial response of the interfaces to the loss of a single selected generating unit within the SBAA. Analysis is performed by switching off a single unit with generating capacity greater than 500 MW in order to assess the inrush requirement at each interface for that particular unit. Siemens PSS/E is used to examine the generator governor’s response for all the generators in the Eastern Interconnection modeled thirty seconds after the loss of the major unit. Thirty seconds was selected to allow the generator governors time to settle out at the new operating point. Analyses are performed to determine the generation response from utilities interconnected with the SBAA. The amount of this response multiplied by the MW of lost generation forms the basis of total TRM.

The largest MW response of each interface (for the outage of units under consideration) is selected and summed. The TRM allocation for each interface is found by dividing the largest response for the interface by the sum and multiplying this value by total TRM.

C. Databases used in TRM assessments. The following databases are utilized in the TRM assessment:

- Southern Companies’ Dynamics Database for Transmission Planning Models
- SERC Dynamics Study Group – Dynamics Database
- NERC MMWG Dynamics Model

TRM values are maintained in the OASIS database.

D. Conditions under which the Transmission Provider uses TRM. The Transmission Provider reserves TRM only to calculate firm ATC for imports and such capacity is made available to the market on a non-firm basis.
**Capacity Benefit Margin ("CBM"):**

1. **CBM practice for both the operating and planning horizons.**

   A. Entity that performs the resource adequacy analysis for CBM determination. Each LSE is responsible to make its own CBM determination. For the Transmission Provider, resource adequacy analyses for determination of CBM are conducted by Southern Company Services, Inc.’s (“SCS”) Resource Planning group as agent for the Transmission Provider in its provision of electric service to its franchised service territories.

   B. Methodology used to perform generation reliability assessments. The Transmission Provider has established a target reserve margin for generation adequacy planning which is the point where total reliability costs and capacity costs are minimized. Resource adequacy is regulated by the Transmission Provider’s respective State commissions. In order to maintain this minimum cost point, some level of CBM reservation is required. Probabilistic analyses using Monte Carlo techniques and historical data are conducted to determine the optimum reserve margin based on different levels of CBM. The resource adequacy analyses utilize CBM in a similar manner to that of firm territorial capacity resources in the determination of the optimum (overall least cost) reserve margin. As such, the methodology utilized to determine the quantity of CBM set-aside is (1) consistent with the Transmission Provider’s methodology for assessing resource adequacy, and (2) is an integral part of such target reserve margin/resource adequacy determination.

   The Monte Carlo method considers generating unit forced outages and de-rates 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 are inputs to the model. It is anticipated that this assessment will be conducted at least every three years and reviewed annually, and may be performed more frequently if system conditions or assumptions change significantly.

   C. Explanation of whether the assessment reflects a specific regional practice. The evaluation methodology does not reflect any specific regional practice.

   D. Assumptions used in the resource adequacy assessment. The evaluation methodology contains many assumptions including: Load Forecast Error (LFE) (discussed below), weather uncertainty, machine outage rates (forced and planned) and repair durations, availability of conventional hydro resources, availability of tie assistance, and other factors.
LFE is determined from statistical analysis of historical forecasts versus actual loads. The resultant probability distribution represents the load forecast uncertainty.

The effect of weather on system load is calculated using trend analyses of historical temperature versus load data for each year evaluated, typically incorporating the data from numerous preceding years. Results from this analysis are input to the model along with the target peak demand hourly system loads for each of the years.

E. **Basis for the selection of paths on which CBM is set aside.** Paths for CBM are chosen across interfaces with neighboring Balancing Authority Areas shown in SERC published data as having sufficient excess generation resources. Total import capability from tie lines during peak hours is a function of both tie line limits and the projected 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. Outside the computer model, the relative availability of generation and transmission capability is considered in order to allocate the desired CBM across the various interfaces.

2. **Additional CBM Information.**

A. **Definition of CBM.** CBM is that amount of firm, import TTC on interfaces with adjacent Balancing Authority Areas reserved by LSEs to ensure access to generation resources from interconnected systems to meet generation reliability requirements of LSEs' native/network load customers.

B. **List of databases used in calculations to determine CBM.** Inputs to the resource adequacy model are developed from various sources and are consistent with those used to develop the Transmission Provider’s integrated resource plan. A listing of the primary databases follows:

<table>
<thead>
<tr>
<th>Database Name</th>
<th>Data Utilized</th>
</tr>
</thead>
<tbody>
<tr>
<td>Southern Company System Planning Database</td>
<td>Machine data (e.g., min/max output, heat rate, delivered fuel cost, startup and VOM costs, emissions cost, planned outages, etc.)</td>
</tr>
<tr>
<td>NERC’s GADS database</td>
<td>Historical forced outage information</td>
</tr>
<tr>
<td>Platts Energy Market Data</td>
<td>Historical pricing for energy strips</td>
</tr>
<tr>
<td>SC Marketing Services Barrons Reports</td>
<td>Load forecasting data</td>
</tr>
<tr>
<td>Southern Company Historical Load/Temp Data</td>
<td>Historical load and temperature data</td>
</tr>
</tbody>
</table>
C. Double-counting of contingency outages when performing CBM, TTC, and TRM calculations. TRM is the amount of TTC necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. CBM is that amount of firm, import TTC on interfaces with adjacent Balancing Authority Areas reserved by LSEs to ensure access to generation resources from interconnected systems to meet generation reliability requirements of LSEs’ native/network load customers. In addition, neither TRM nor CBM are used to calculate TTC. Therefore, there is no double-counting of contingency outages when performing CBM, TTC and TRM calculations. Analysis software for the determination of CBM utilizes a transport model instead of a transmission model; contingencies are not explicitly modeled.

3. Procedures for allowing the use of CBM during emergencies.

When an Emergency (as defined below) occurs, CBM may be called upon by the LSE that reserved the CBM to import power on a firm basis into the SBAA to ensure the continued reliability of service to the LSE’s native/network load customers.

A. What constitutes an Emergency. An Emergency exists when the resources of an LSE are projected to be insufficient to serve its native/network load customers. Such Emergency meets the conditions established by NERC EEA2.

B. Entities that are permitted to use CBM during an emergency.

   (i) Eligibility for use of CBM. CBM is available for the Transmission Provider and Network Customers taking Network Integration Transmission Service under the Tariff to serve their respective native/network load. For such Network Customers who only serve a portion of their load under Part III of the Tariff, any CBM reserved shall be limited to that reasonably needed for the Network Customer’s load served under Part III of the Tariff.

   (ii) Reservation Of CBM. Each eligible LSE is responsible for reserving its own CBM requirements. To make such a reservation, the LSE must submit a request to the Transmission Provider’s transmission function setting forth the following information: (a) the amount of CBM desired on each particular interface; (b) a description of the methodology used to determine its CBM; and (c) the basis for reserving CBM on the requested paths. The Transmission Provider’s 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, including higher queued long-term firm requests under the Tariff. The Transmission Provider’s transmission function reserves the right to deny CBM requests that appear unreasonable or disproportionate given the amount of native/network load service being provided to that LSE by the
Transmission Provider’s transmission system, with Network Customer’s taking Network Integration Transmission Service under the Tariff limited to that reasonably needed for the amount of load served under Part III of the Tariff.

(iii) **Use of CBM.** CBM may be used during an Emergency by the LSE who reserved it to import power on a firm basis into the SBAA to ensure the continued reliability of service to native/network load customers.

(iv) ** Availability of Reserved CBM Capacity to Other Customers.** Transmission capacity reserved for CBM will be made available on a non-firm basis when CBM is not needed to maintain system reliability during periods of projected resource deficiencies.

C. **Procedures which must be followed by the Transmission Provider and other eligible LSEs when they need to access CBM.** The procedures to be followed in using reserved CBM are outlined below:

(i) The LSE will make a reservation on OASIS for Network Integration Transmission Service (Type = Network; Class = Firm; Increment = Daily, Weekly, Monthly, Yearly) on a specific path on which it has reserved CBM.

(ii) The LSE will note in the comment section of the network service template that the reservation is for the use of CBM capacity on the path.

The Transmission Provider’s transmission function will evaluate the transmission service request and provide the requested CBM transmission service on a firm basis if it is reasonable and sufficient transmission capacity is available on the path.

**Coordination of ATC Calculations with Neighboring Systems**

The Transmission Provider participates with the SERC Intra-Regional Near Term Study Group to develop quarterly OASIS power flow cases for the upcoming five quarters. These cases are derived from the SERC Intra-Regional Long Term Study Group’s “Yearly” base cases, which are an aggregation of each SERC participant’s transmission planning model for their respective systems. The SERC OASIS power flow cases incorporate the system topology, facility ratings, generation dispatch, system demands (load forecasts), and transmission uses provided by each SERC participant.

The Transmission Provider further coordinates with its Tier 1 neighbors to receive inputs on a monthly basis to update the quarterly SERC OASIS power flow cases into thirteen monthly power flow cases. These monthly inputs include updates to system parameters associated with each individual month. The Transmission Provider adds to these inputs the specific firm transmission service commitments that are expected to be scheduled to create the SBAA monthly power flow cases which are used for monthly TTC assessments.
The Transmission Provider provides continuous access to transmission service requests and commitments through its OASIS. The Transmission Provider participates with the SERC Intra-Regional Near Term Study Group to provide monthly coordination of all confirmed firm monthly and yearly transmission service commitments. The Transmission Provider provides hourly updates of outage information through the NERC SDX. The Transmission Provider issues its transfer capability methodology to adjacent Reliability Coordinators, Transmission Operators, and other entities that indicate a reliability-related need in accordance with NERC requirements.

The Transmission Provider also participates in the Florida-Southern Coordinating Group to develop coordinated transfer capability values between the SBAA and the FRCC. The joint studies and the resulting transfer capabilities are provided to the Reliability Coordinators and to participating Transmission Providers for use in their respective OASIS postings.