Eastern Interconnection Planning Collaborative

The following document is in response to data requests provided by the EISPC on June 28, 2010. The narratives contained in this document are intended to convey the processes by which the Planning Authorities ("PA") participating in the EIPC develop the transmission models utilized in transmission planning of their respective areas. Also included as part of this submittal are two (2) excel files containing 1) the transmission plans of each PA that are reflective in the 2020 roll-up case and 2) the resource assumptions that are contained within the same case. Below is a list of the participating PAs that comprise the EIPC.

- **Alcoa Power Generating**
- **American Transmission Company**
- **Duke Energy Carolinas**
- **Electric Energy, Inc.**
- **Entergy ***
- **E.ON (Louisville/Kentucky Utilities)**
- **Florida Power & Light**
- **Georgia Transmission Corporation**
- **IESO (Ontario, Canada)**
- **International Transmission Company**
- **ISO-New England ***
- **JEA (Jacksonville, Florida)**
- **MAPPCOR ***
- **Midwest ISO ***
- **Municipal Electric Authority of Georgia**
- **New Brunswick System Operator**
- **New York ISO ***
- **PJM Interconnection ***
- **PowerSouth Energy Coop**
- **Progress Energy – Carolinas**
- **Progress Energy – Florida**
- **South Carolina Electric &Gas**
- **Santee Cooper**
- **Southern Company ***
- **Southwest Power Pool**
- **Tennessee Valley Authority ***

**** Also a Principal Investigator on the DOE proposal***

Eastern Interconnection Planning Collaborative

Alcoa Power Generating (APGI – Yadkin)

APGI-Yadkin transmission planning is a yearly process and is based on a five and ten year study. System studies are based on MMWG models which are further modified to include the latest load forecast and any improvements of the transmission system, and generation changes.

APGI-Yadkin has no new transmission or generation expansions planned from the present time until 2020.

American Transmission Company

Contained with Midwest ISO’s narrative.

Duke Energy Carolinas

Duke Energy Carolina's ("DEC") transmission planning is a continuous process and covers the 10 years of the planning horizon. The process determines the necessary enhancements to the existing transmission system to meet the following objectives:

- Provide an adequate transmission system to serve the network load of the Duke Energy Carolinas service territory.

- Maintain adequate transmission thermal capacity and reactive power reserves (in the generation and transmission systems) to accommodate scheduled and unscheduled transmission and generation contingencies.

- Achieve compliance with the NERC Reliability Standards that are in effect.

- Adhere to applicable regulatory requirements.

- Provide for comparable service under the Duke Energy Carolinas, LLC FERC Electric Tariff.

- Satisfy contractual commitments and operating requirements of inter-system transactions.

The planning is based on MMWG models which are further modified in collaboration with SERC members to provide updated information for the SERC region. DEC's data includes the latest updates on:

1) DEC's Annual Plan filing provided to the NC and SC utilities commission which identifies DEC's integrated resource plan, and resource information required annually from load serving entities (LSE) under the Duke OATT. The information identifies the on and off system resources that are expected to meet each LSE's load forecast over the planning horizon. New generation with a signed interconnection agreement is included in the model but is not dispatched unless it is specified as a resource by an LSE or has confirmed annual firm or longer transmission service. In future years' cases, it is often necessary to incorporate unplanned/unsited generation (fictitious) in the model to meet load growth. The transmission planner uses Information such as past interconnection studies or brownfield (retired generation/industrial) sites to determine likely locations for placing fictitious generation in the models. Knowledge of the fictitious generation's location must be applied when assessing system performance in the future years cases.
2) Transmission facilities that are approved & budgeted or where construction has begun are included in the models. Other projects the planners believe have a

high certainty of being in service in the year being modeled are also included. Engineering judgment is applied such that a new or upgraded facility that is marginally needed may not be included in the base model so that the timing of the need for the facility can be accurately determined.

3) All OATT annual firm or longer transmission service confirmed by DEC's customers

DEC's transmission expansion plan is the compilation of transmission facility improvements and upgrades which are necessary for the transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC Reliability standards. The expansion plan is based on information obtained through DEC's internal planning efforts as well as through the SERC Long Term Study Group, North Carolina Transmission Planning Collaborative, Southeastern Inter-Regional Participation Process, and joint studies with interconnected neighbors.

Eastern Interconnection Planning Collaborative

Electric Energy, Inc.

At Electric Energy, Inc (EEI), the Technical Services Department is responsible for planning the orderly and economic development of the EEI Bulk Electric System (BES). To aid in these activities, the Technical Services Department makes use of consulting companies. Such planning activities include the analysis and evaluation of the EEI transmission system response to generation and transmission system expansion plans, and expected power purchased by EEI and others through short-term and long-range transmission planning studies. The transmission system analysis is carried out through active participation in NERC and SERC committee work, as well as internal EEI transmission planning studies. The objective of EEI is to provide adequate electrical capacity and transfer capability to serve EEI customers with acceptable reliability, commensurate with cost, and to accommodate power transfers by others without excessively burdening the EEI system. The challenge in planning is to determine the optimum plan for an uncertain future.

EEI subscribes to all NERC and SERC planning standards, which are available from those organizations. EEI transmission planning criteria and guidelines, at a minimum, conform to those NERC and SERC Planning Standards, as they pertain to transmission planning.

The Study Models used for EEI planning shall be based on the ERAG Multi-region Modeling Working Group (MMWG) models and the related SERC seasonal assessment models. EEI participates annually in building the MMWG models and in the preparation of seasonal assessment models for near term and long term summer and winter assessments as requested by SERC.

EEI has no native load within its service territory. As a result, the net system import requirements are essentially zero. Historically, the Paducah Gaseous Diffusion Plant (PGDP) is the major customer for EEI. The general transmission planning philosophy is to provide adequate and sufficiently reliable generating plant outlet transmission capability to assure that the needs of the PGDP are satisfied, and during periods of light PGDP load, EEI has sufficient transmission transfer capability to export the full EEI generation capacity.

Entergy

Transmission facilities included in the 2020 roll-up model

Entergy included in the 2020 roll-up model transmission projects identified in Entergy's 2010 – 2012 Final Construction Plan Update 5 posted on OASIS. This includes projects identified as either Approved, Proposed and In Target, or listed in the Identified Target Areas section of the construction plan. An Approved project is a project that is committed to being completed by the projected in service date. A project shown as Proposed and In Target is a project that is currently funded for scoping and preliminary engineering with an expected construction commencement date within the three year Construction Plan horizon. Identified Target Area projects are conceptual in nature and have been identified in the annual 10 year reliability assessment but are not included in the current three year construction plan window. Due to the uncertainty of the future, final scopes and timing of these conceptual projects could vary.

Resources included in the 2020 roll-up model

Entergy generation modeled in the case includes all in-service units and any planned units that have firm transmission service scheduled from them after their completion. The resource plan assumed in the 2020 roll-up model is driven by the need to satisfy reserve margin obligations and to meet energy demand during system peak load conditions. To meet the area requirements firm generation is dispatched in the model, followed by non-firm network resources, generation owned by the LSEs and then non-firm energy only resources. Entergy dispatches generation representing firm energy contracts and economically dispatches firm network resources for load. Additional generation is dispatched on a pro-rata basis in the following order: non-firm network resources, LSE-owned non-firm energy-only generation, then non-firm, energy-only resources within the BA that are owned by others

The model includes a planned generating unit at Plum Point with an expected in-service of summer 2012. The model also includes a conceptual CCGT at Entergy's Lewis Creek Plant in the 2019 time frame.

Eastern Interconnection Planning Collaborative

E.ON (Louisville/Kentucky Utilities)

Purpose

The primary purpose of EON's transmission system is to reliably transmit electric energy from Network Resources to Network Loads. EON has established Transmission Planning Guidelines to gauge the adequacy of the transmission system to supply projected Network Customer demand and contracted Long-Term Firm Point-to-Point Transmission Services. The Process is an annual cycle designed to incorporate external Network changes and to provide information for regional evaluation and coordination through the NERC MMWG model building process.

Models

Seasonal peak power flow models are developed annually (first quarter) by EON using each model year available in the most recent NERC ERAG Model series. The topology of the EON transmission system is expanded to provide a more detailed representation of the 69 kV facilities and updated to reflect the current Transmission Expansion Plan. Network Resources and Network Loads are updated to reflect the most recent information from the Network Customers. Seasonal peak cases may also be developed without certain generator and/or major transmission additions to provide better models for interpolation between model years.

Evaluation

The Transmission Expansion Plan is evaluated and updated through screening, verification, area studies, facility studies, signed agreements, and other periodic studies. Generator and transmission contingency simulations are routinely performed to evaluate the adequacy of the transmission system against the no "Loss of Demand or Curtailment of Firm Transfer" requirements of the Transmission Planning Guidelines.

- Screening – Generator and transmission contingencies are simulated on the Base Cases to identify overloads and low voltages not resolved by the Transmission Expansion Plan.
- Verification – Projects in the Transmission Expansion Plan and issues identified in the screening are evaluated to determine the required completion date, to determine the upgrade or construction required and to identify the reason for the change. The required completion date is determined by interpolating flows between model years.
- Area Studies – Area studies are performed prior to major construction to develop multiple long-term options that provide adequate transmission through the planning period. The least-cost option is recommended for approval and the associated projects are incorporated into the Transmission Expansion Plan.
- Facility Studies – Facility studies are performed following a request made by customers through the ITO by a Network Integrated Transmission Service (NITS), Designated Network Resource (DNR), or Point-To-Point (PTP) request. Multiple options with an associated cost and time frame to complete construction

to provide the requested service is provided back to the customers through the ITO.

- Signed Agreements – Construction and upgrades associated with Generator Interconnections, Transmission to Transmission Interconnections, and Network Service requests executed by the requestor, which have been submitted to and evaluated by the ITO and EON in the previous year, are incorporated into the Transmission Expansion Plan.

Periodically, studies are performed to evaluate the adequacy of the EON transmission system against the allowable “Loss of Demand or Curtailment of Firm Transfer” requirements (level 3 and above events) and “System Stability”. Necessary construction and upgrades identified by these studies are incorporated into the Transmission Expansion Plan.

ITO/RC Approval

Annually, the Transmission Expansion Plan is submitted to the ITO and RC for independent review, evaluation and comment regarding any outstanding issues that should be addressed. The final plan developed by the Transmission Owner must be approved by the ITO.

Florida Power & Light

Load Forecast
The 2009 ten year demand forecast for the FRCC region is projected to have a compounded average annual growth rate of 1.8 percent compared to last year's compounded growth rate of 2.1 percent. FRCC entities use historical weather databases consisting of 20 years or more of data for the weather assumptions used in their forecasting models. Historically, the FRCC has high-demand days in both the summer and winter seasons. However, the summer season historically has a significant greater frequency of higher demand days and thus, for planning purposes, is considered the critical season.

Each individual LSE within the FRCC Region develops a forecast that accounts for the actual peak demand. The individual peak demand forecasts are then aggregated by summing these forecasts to develop the FRCC Region non-coincident forecast. These individual peak demand forecasts are coincident for each LSE but there is some diversity at the region level. The Regional non-coincident forecast is the basis for the evaluation of adequate levels of resources to meet reserve margin requirements. The entities within the FRCC region plan their systems to meet the Reserve Margin criteria under both summer and winter peak demand conditions.

There are a variety of energy efficiency programs implemented by entities throughout the FRCC region. These programs can include commercial and residential audits (surveys) with incentives for duct testing and repair, high efficiency appliances (air conditioning, water heater, heat pumps, refrigeration, etc.) rebates and high efficiency lighting rebates.

The 2009 ten year net internal demand forecast includes the effects of 3,804 MW of potential demand reductions from the use of load management (3,019 MW) and interruptible demand (785 MW) by 2018. Demand Response is considered as a demand reduction. Entities within the FRCC use different methods to test and verify Direct Load Control programs such as actual load response to periodic testing of these programs and the use of a time and temperature matrix along with the number of customers participating.

Currently there is no Renewable Portfolio Standard (RPS) in Florida. A draft rule was submitted by the Florida Public Service Commission staff to the Florida Legislature for consideration; however, the Florida Legislature has not established Renewable Portfolio Standards in Florida. Projections incorporate demand impacts of new energy efficiency programs. Each LSE within the FRCC treats every Demand Side Management load control program as "demand reduction" and not as a capacity resource.

FRCC projected demand is primarily driven by the variability of weather and economic assumptions. Currently, the FRCC is actively evaluating alternative methodologies to evaluate the potential variability in projected demand due to weather, economic, or other key factors. The FRCC is working to develop regional bandwidths based upon hourly load shape curves for the FRCC Region. The purpose of developing bandwidths on peak demand is to quantify uncertainties of demand at the regional level. This would include weather and non-weather demand variability such as demographics, economics, and price of fuel and electricity.

Generation

FRCC supply-side resources considered for this ten year assessment are categorized as Existing (Certain, Other and Inoperable). The FRCC Region counts on 51,338 of Existing Certain resources of which 44 MW are hydro and 468 MW are Biomass. Potential solar capacity is projected at 33 MW, however, most of this capacity is derated with approximately 3 MW considered as a firm resource available during peak demand, with the remainder being utilized as an energy-only resource. Existing other merchant plant capability of 1,438 MW to 1,838 MW is potentially available as future resources of FRCC members and others.

There are a total of 2,212 MW of Existing Inoperable resources for 2010. Approximately 1,300 MW of this capacity is being removed for plant modernization, while the balance capacity includes mostly older less efficient generating capacity being placed into operational standby until forecasted loads resume to pre-recessional trends. There are a net total of 456 MW of Future Planned resources for 2010. By 2019, Future Planned net resources are expected to be 6,506 MW of which 571 MW are categorized as Biomass, with solar resources achieving almost 13 MW of firm capacity.

FRCC entities have an obligation to serve and this obligation is reflected within each entity's 10-Year Site Plan filed annually with the Florida Public Service Commission. Therefore, FRCC entities consider all future capacity resources as "Planned" and included in Reserve Margin calculations.

Capacity Transactions on Peak

The FRCC Region does not consider Expected or Provisional purchases or sales as capacity resources in the determination of the Region's Reserve Margin. The Firm interregional imports for 2010 are 2,175 MW and are expected to increase by 2019 to 2,372 MW. These imports have firm transmission service to ensure deliverability. The FRCC Region does not rely on external resources for emergency imports and reserve sharing. However, there are emergency power contracts (as available) in place between SERC and FRCC members.

The FRCC Region has 143 MW of generation under Firm contract to be exported during the summer into the Southeastern Subregion of SERC throughout 2019. These sales have firm transmission service to ensure deliverability in the SERC region.

Georgia Transmission Corporation

General

Georgia Transmission Corporation (GTC) and Georgia System Operations Corporation (GSOC) grew out of Oglethorpe Power Corporation (OPC), created in 1974 to be the primary supplier of electricity to 39 of the 42 Electric Membership Corporations (EMCs) throughout Georgia. In 1997 Oglethorpe Power Corporation undertook one of the most comprehensive restructuring efforts of its kind by moving from the traditional vertically integrated organization to become 3 separate generation, transmission and system operation entities. OPC provides the generation and asset management function. GTC owns and maintains the EMC's share of the Integrated Transmission System (ITS) and provides transmission services. GSOC provides system operation support. GSOC economically operates the generation and transmission assets of OPC and GTC, respectively while adhering to reliability standards of the North American Electric Reliability Corporation (NERC) and the SERC Reliability Corporation (SERC).

Load Forecast

GTC works with their associated 39 Electric Membership Cooperatives to develop a local load forecast for each substation. This data is input into the creation of the Georgia ITS load Forecast that is used by Southern Company to develop the annual power flow base case models for the Southern Balancing Authority Area (SBAA).

Resource Requirements

GTC works with Scheduling Member Groups (SMG's) which have the responsibility to develop generation resource plans for their associated Electric Membership Cooperatives. This information is collected annually during the fall update of the power flow base case library and is updated as necessary throughout the year. The SMG generation resource plans are combined into one overall plan to meet the combined load/loss obligation. The combined SMG generation resource plan is provided to Southern Company for use in developing the power flow base cases. Southern Company's economic load dispatch software is used to match GTC generation to the GTC load when base cases are developed.

Interchange

The ITS Participants each have an allocated share of the total transfer capability for SBAA interfaces that include Georgia ITS interconnection facilities. GTC's confirmed annual transmission reservations are included in the SBAA power flow models.

Major Transmission Facilities

Georgia Transmission Corporation's (GTC) transmission system is part of the Georgia Integrated Transmission System (ITS) which is embedded in the SBAA transmission grid. Other co-owners of the ITS include: Dalton Utilities, Georgia Power Company and MEAG Power. While individual transmission lines and substations in the ITS are owned and maintained by the individual participants, they are planned and operated as one system. The ITS Participants engage in joint planning to ensure that transmission facilities that are built for the ITS collectively benefit the ITS Participants. GTC's transmission planning is a yearly, continuous process and is based on a rolling 10-year cycle, in which needed enhancements to the existing transmission system are identified for the next 10 years.

The expansion of the transmission system is based on seasonal developed SBAA models, which are further modified in collaboration with SERC members to provide a more detailed representation of the SERC region. These models are incorporated into the power flow models of the interconnected regions of NERC through the ERAG MMWG annual update process. The most recent ERAG MMWG model series are then used to represent the external systems in updated SBAA models. These updated SBAA models data includes the latest updates on the following:

1) Generation resource assumptions that are provided by the Load serving entities (and/or their designate agents) for the ITS Participants and Southern Company affiliates

2) Load forecast assumptions that are provided by the Load serving entities (and/or their designate agents) for the ITS Participants and Southern Company affiliates

3) Transmission services accepted by the customer, including the associated transmission upgrades, if any.

The 10-year Transmission Expansion Plan for the Southern Balancing Authority Area is the compilation of transmission facility improvements and upgrades which are necessary for the transmission system (which includes GTC's Facilities) to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC TPL standards.

GTC actively participates in the ITS project review and development process in order to ensure that GTC's individually owned and planned facilities are properly represented in the base cases.

Eastern Interconnection Planning Collaborative

IESO (Ontario, Canada)

Planning in Ontario is conducted on two fronts - assessing future system conditions with known and expected facilities in place, and developing future plans on resources and transmission to meet the needs of the system. Both processes use applicable NERC reliability standards and NPCC regional reliability standards to evaluate the reliability performance of the proposed projects.

On the assessment front, the IESO, as the Planning Coordinator, conducts transmission and resource adequacy assessments as follows:

- An Ontario Reliability Outlook with a five-year horizon, that is issued annually;
- An 18-Month Outlook Update that is conducted semi-annually;
- A Review of Resource Adequacy with a 5-year horizon, submitted annually to NPCC, and
- A Review of Transmission Adequacy with a 5-year horizon, submitted annually to NPCC

These assessments provide an evaluation of the future conditions such as system constraints and resource adequacy based on planned system conditions; they do not propose resource or transmission plans to meet adequacy needs or to alleviate system constraints. Market participants use the information provided in the reports to make decisions on investments in the power system assets.

In 2005, the Ontario Government established the Ontario Power Authority (OPA) to address the long-term system planning. Part of the OPA's mandate is to develop an Integrated Power System Plan (IPSP) to provide an independent and integrated plan for conservation, generation and transmission over a 20 year period.

Through OPA's planning activities, the OPA identifies resource and transmission requirements, procures resources and promote conservation as required to ensure supply adequacy and respond to other system and policy needs. Transmission Owners develop options to meet the transmission facility proposals, which include route selections, line types, associated facilities, etc. These options are evaluated by the IESO through the System Impact Assessment (SIA) process, to evaluate system performance under forecast system conditions and when subjected to various contingencies.

The applicable seasonal peak power flow models developed annually by IESO for MMWG available in the most recent NERC ERAG Model series are updated to include all future transmission and generation projects in Ontario that passed the IESO Connection Assessment and Approval (CAA) process were modeled along with any upgrades required to maintain the reliability of the IESO system including the future transmission and generation.

International Transmission Company

ISO-New England

ISO New England's portion of the 2020 roll-up case includes all future projects that have been reviewed as outlined under section I.3.9 of the ISO New England tariff. Pursuant to section I.3.9, proposals for new generation and transmission facilities rated at or above 69 kV that are found to not have significant adverse impact on the stability, reliability and operating characteristics of existing electrical infrastructure through study and analysis are then approved and considered assumed future infrastructure. From this point on, market participants and transmission owners are free to proceed with construction and implementation of the project.

Generation projects which are current and active in the ISO New England generation interconnection processes, and which have been reviewed pursuant to section I.3.9, have been included in the model.

In the case of transmission projects, projects submitted for review pursuant to section I.3.9 are those which are being developed and generally supported as part of the New England regional transmission planning process.

Eastern Interconnection Planning Collaborative

JEA (Jacksonville, Florida)

Included as part of Florida Power and Light.

Eastern Interconnection Planning Collaborative

MAPPCOR

MAPP's expansion planning process is an annual process for the 10-year planning horizon. For this 10-year planning horizon needed enhancements to the existing transmission system are identified for the next 10 years.

The expansion of the transmission system is based on MAPP's updated models with the ERAG MMWG models representing the external system.

The expansion plans included in the models include the latest updates on:

1. Resource assumptions.

   The resource assumptions included are the latest generation updates/expansions reported through the open process of the MAPP sub regional planning groups (SPGs) activity and sub regional plans submitted by the MAPP SPGs and approved through the MAPP Transmission Planning Subcommittee (TPSC).

2. Transmission assumptions.

   The transmission assumptions included are the latest transmission expansion additions reported through the open process of the MAPP sub regional planning groups (SPGs) activity and sub regional plans submitted by the MAPP SPGs and approved through the MAPP Transmission Planning Subcommittee (TPSC). Planned projects are the preferred solution to an identified issue. Proposed projects are the tentative solution to an identified issue.

3. Load forecast and long-term firm transmission service input assumptions.

   The MAPP Transmission Owners provide this information through the model building process.

Therefore, MAPP's 10-year Transmission Expansion Plan (MAPP Regional Plan) is a 10 year plan which is the compilation of transmission facility improvements and upgrades which are necessary for the MAPP transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC TPL standards, MAPP's Restated Agreement and MAPP's Attachment K open regional planning process.

Midwest ISO

Midwest ISO performs transmission planning in an annual process for the 10-year planning horizon, in which Planned and Proposed enhancements to the existing transmission system are identified for the next 10 years.

The expansion of the transmission system is based on Midwest ISO developed models with ERAG MMWG models or more current updates from adjacent entities used to represent the external system. The models include the latest updates on:

1) Resource assumptions from the Midwest ISO generation interconnection process and resource forecasts based on public policy requirements. Future generators with signed interconnection agreements are included in models. Future generators associated with public policies which are law (E.g. Renewable Portfolio Standards) are included in the amounts required to meet the standards for the study year.
2) Load forecast assumptions reflective of Load Serving Entity forecasts as provided by the Transmission Owners of Midwest ISO through internal model building process
3) Long-term firm transmission services accepted by the customer including the associated transmission upgrades, if any.
4) Planned transmission projects include previously approved projects and those that are expected to be approved within the current planning cycle. Proposed projects are those that have demonstrated the ability to address a demonstrated transmission issue and are expected to be approved (or an equivalent) in a future planning cycle.

Midwest ISO Transmission Expansion Plan (MTEP) is a 10 year plan which is a compilation of transmission project improvements and upgrades which are necessary for the Midwest ISO transmission system to support the proposed resource assumptions, load forecasts, firm transmission service, and public policy requirements for the next 10 years in the most reliable and economic manner consistent with NERC TPL standards.

Municipal Electric Authority of Georgia

General
The MEAG Power transmission system is part of the Georgia Integrated Transmission System (ITS). Other co-owners of the Georgia ITS include: Dalton Utilities, Georgia Power Company and Georgia Transmission Corporation. This jointly owned system is part of the Southern Company transmission grid. The MEAG Power Planning Process is closely related to that of Southern Company because there is a single System Operator and transmission system improvements are jointly planed among the ITS participants.

Load Forecast
MEAG works with 49 member cities to develop a local load forecast for each substation. MEAG's resource planning department uses economic data to develop MEAG's system load forecast. This data is input into the creation of the Georgia ITS load Forecast that is used by Southern to develop the base case load model.

Resource Requirements
MEAG Power's generation is represented in the current base case. Southern Company's economic load dispatch software is used to match MEAG generation to the MEAG load when study cases are developed.

Interchange
MEAG Power has been allocated a portion of the Georgia ITS interface capacity. All of MEAG's confirmed annual transmission reservations are included in Southern Company's base case models.

Major Transmission Facilities
MEAG Power actively participates in the ITS project review and development process. MEAG ensures that its individually owned and planned facilities are properly represented in the base cases.

Eastern Interconnection Planning Collaborative

New York ISO

The Comprehensive Reliability Planning Process (CRPP) encompasses a ten-year planning horizon and evaluates the future reliability of the New York bulk power system. In order to preserve and maintain system reliability, the NYISO, in conjunction with Market Participants, identifies the reliability needs over the planning period and issues its findings in the Reliability Needs Assessment (RNA). The Comprehensive Reliability Plan (CRP) then evaluates a range of proposed solutions to address the needs identified in the RNA, if any. A request for solutions to identified reliability needs is issued with the expectation that Market-Based Solutions will come forward to meet the identified needs. In the event that Market-Based Solutions are not sufficient, the process provides for the identification of Regulated Backstop Solutions proposed by designated transmission owners, and Alternative Regulated Solutions proposed by any market participant. The NYISO then evaluates all proposed solutions to determine whether they will meet the identified reliability needs. Thus, the Comprehensive Reliability Plan (CRP) is developed, setting forth the plans and schedules that are expected to be implemented to meet those needs.

The following assumptions were included in the EIPC 2020 case based on assumptions made in the CRP.

Load forecast growth rate

The New York Independent System Operator (NYISO) is forecasting a base 2020 summer peak load for the New York Control Area (NYCA) of approximately 35,300 MW which represents an average annual growth rate of 0.78% through 2020.

Impact of energy efficiency and DSM on modeled load

Energy efficiency efforts as required to meet state requirements have not been fully incorporated into the load forecast as the programs are just beginning and a level of conservatism in the base case was desired. For 2020 summer, if the full targets of statewide required efficiency efforts were assumed to be fully met (15% by 2015), an additional reduction in the forecast peak of approximately 2,500 MW would occur. Impacts of demand side programs such as EDRP are not included in the forecasted load. Interruptible load, and distributed generation resources of approximately 2,250 MWs (referred to as Special Case Resources in New York) are not included.

Major transmission facilities

NYISO has included one new DC tie to New Jersey of approximately 660 MW, a new 345 kV controllable AC transmission project into New York City, 230 kV circuits, and various upgrades to existing 345 kV circuits in the 2020 power flow model.

Generation additions/retirements

The NYISO has included several new generation projects in its 2020 power flow model. These are projects that have passed certain milestones to be included in the NYISO planning databases utilized in its Comprehensive Reliability Planning Process. Additionally, the model will represent the New York State Renewable Portfolio Standard of 30% by 2015, which will require approximately 3600 MW of installed nameplate wind turbine capability. Presently, there is approximately 1300 MW of wind turbine power installed in New York. To meet the RPS goal, the model will also include approximately 1000 MW of wind projects that have gone through the interconnection process and accepted their class year cost allocation, along with an additional 1300 MW of wind projects from the NYISO Interconnection Queue

Interchange/firm transmission modeled

The NYISO coordinates its interchange schedule with its neighbors and represents firm transactions and the expected continuance of current external ICAP providers.

Generation dispatch

The NYCA system generation dispatch includes only the impact of firm external transactions.

PJM Interconnection

PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission system upgrades and enhancements to preserve grid reliability, the foundation of competitive wholesale power markets. PJM's RTEP process includes both five year and 15-year dimensions assessment to meet all applicable reliability planning criteria. The applicable reliability planning criteria are listed below:

- NERC Planning Standards (http://www.nerc.com/~filez/standards/Reliability_Standards.html)
- RFC Reliability Principles and Standards (http://www.rfirst.org/Standards/ApprovedStandards.aspx)
- PJM Reliability Planning Criteria as contained in Manual M14B Attachment G (http://www.pjm.com/documents/manuals.aspx)
- Transmission Owner Reliability Planning Criteria as filed in their respective FERC 715 filing.

Five-year-out planning enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. PJM's 15-year planning horizon permits consideration of many long-lead-time transmission options. These options often comprise larger magnitude transmission facilities that more efficiently and globally address reliability issues. Typically, these are higher voltage upgrades that simultaneously address multiple NERC reliability criteria violations at all voltage levels. A 15-year horizon also allows PJM to consider the aggregate effects of many system trends including long-term load growth, impacts of generation deactivation and broader generation development patterns across PJM.
New RTEP recommendations are submitted to PJM's independent Board of Managers (PJM Board) periodically throughout the year to resolve identified reliability criteria violations. Once approved, they become part of PJM's overall RTEP.

Models Building Process

Five year and 15-year Seasonal peak power flow models are developed annually by PJM using each model corresponding year available in the most recent NERC ERAG Model series. The case build is a collaborative process that involves PJM, PJM transmission owners, and neighbors. The case was reviewed with all PJM transmission owners to ensure that all existing and planned facilities were modeled. All future transmission upgrades with a required in-service date. The topology of the PJM transmission system is expanded to provide a more detailed representation of the 69 kV facilities and updated to reflect the current Transmission Expansion Plan. All existing generation was modeled in the base case. Future generation that had an executed

Interconnection Service Agreement (ISA) was modeled along with any upgrades required to maintain the reliability of the PJM system including the future generation. Future merchant transmission facilities that had an executed Facility Study Agreement (FSA) were modeled along with any upgrades required to maintain the reliability of the PJM system including the future merchant transmission.

Eastern Interconnection Planning Collaborative

PowerSouth Energy Cooperative

PowerSouth's transmission planning is a yearly, continuous process and is based on a rolling 10-year cycle, in which needed enhancements to the existing transmission system are identified for the next 10 years. PowerSouth coordinates with Southern Company and South Mississippi Electric Power Association (SMEPA) to assure accurate modeling of tie lines and other shared ownership resources, as well as area interchange values. PowerSouth also submits data to SERC's Long Term Study Group (LTSG) which is used to create the MMWG models.

The expansion of the transmission system is based on MMWG models which are further modified to include the latest updates from other Planning Authorities in the Southern Sub-region of SERC. This includes resource assumptions, load forecast assumptions, and topology changes.

PowerSouth's 10-year Transmission Expansion Plan is the compilation of transmission facility improvements and upgrades which are necessary for the PowerSouth transmission system to support planned resource additions and customer load requirements for the next 10 years in the most reliable and economic manner consistent with NERC TPL standards.

Annual Assessment

The PowerSouth Transmission Assessment is performed each year based on that year's set of cases. The goals of the study are to stress and analyze the bulk electric system of PowerSouth according to the NERC planning standards as well as PowerSouth's own planning guidelines and criteria. From this assessment, the PowerSouth system should be capable of performing reliably under a wide range of expected conditions while continuing to operate within thermal and voltage limits. The goal of this study is to assure compliance with the NERC standards and to assure that improvements necessary to remain compliant with the standards are included in the Transmission Expansion Plan.

NERC Standards

NERC and the electric industry's efforts to ensure a reliable transmission grid has resulted in the TPL Planning standards which includes TPL-001, TPL-002, TPL003, and TPL-004. These TPL standards are summarized in Table 1 of the Standard and this process is commonly referred to as Table 1 analysis. Table 1 is composed of contingency categories of increasing severity A through D. The following is a discussion of the Table I analysis and how it was applied to the PowerSouth bulk electric system. The rationale for contingencies selected is covered in the Compliance Strategy Matrix for each NERC Category, which is a separate document found in the appendix.

Model Creation/Updating

The system models used for this study are a product of an annual effort between PowerSouth, Southern Company, SMEPA, and others in the SERC region. Annually, eleven (11) summer peak cases representing the forward looking ten years plus one more year, are developed for use in analysis by the participating utilities. Confidence is high in the accuracy of the model in the early years, but as time moves out to years 6-10, the models become less certain. One of the reasons for this is the unknown addition of generating plants to the region. The addition of these plants can have a significant impact on the transmission system in the area. These models do, however, contain the most recent information for not only the PowerSouth system, but also the surrounding utilities. Siemens PTI's PSS/E power flow simulation program is used to study the power system by PowerSouth. The PSS/E activity ACCC (AC Contingency Checking) was used to scan the system for N-1 and N-2 contingencies. In addition to the ACCC runs, many areas were examined by manually removing lines and buses from service or creating special subsystem, monitor, and contingency files. Post processing of the data was done mainly in Excel.

Seasonal Variations and Sensitivities

It is recognized that seasonal variations in load and ambient temperature have an effect on the bulk electric system. This study therefore, utilizes eight (8) different load levels to test or analyze the system. These seasons are Gross Summer, Contract Summer, Summer Shoulder, Spring Peak, Spring Valley and Winter Peak, Fall Peak, and Hot Summer. The definitions of each seasonal case are as follows:

Gross Summer – 100% of PowerSouth's summer peak load, all generation dispatched to full, all purchases modeled (including SEPA allocation to SMEPA), and a 3600 MW export from Southern to Florida.

Contract Summer - 100% of PowerSouth's summer peak load, all generation dispatched to full, all purchases modeled (including SEPA allocation to SMEPA), and a 2400 MW export from Southern to Florida.

Summer Shoulder – 93% of PowerSouth's summer peak load, all generation with the exception of SEPA hydros dispatched to full, all purchases modeled (including SEPA allocation to SMEPA). This is a sensitivity to test the system without any hydro generation. PowerSouth generation is assumed to be economically dispatched.

Spring Peak – 75% of PowerSouth's winter peak load, all transmission lines given the normal summer rating, generation economically dispatched, and all purchases modeled(including SEPA allocation to SMEPA).

Spring Valley – 25% of PowerSouth's winter peak load, all transmission lines given the normal summer rating, generation was economically dispatched, and all purchases modeled (no SEPA power).

Winter Peak – 100% of PowerSouth's winter peak load, all transmission lines given the winter rating, all generation dispatched to full, and all purchases modeled (including SEPA allocation to SMEPA).

Fall Peak – 83% of PowerSouth's summer peak load, all transmission lines given the normal summer rating, generation economically dispatched, and all purchases modeled (including SEPA allocation to SMEPA).

Hot Summer – 104% of PowerSouth's summer peak load, all transmission lines given the summer rating (Rate A -104ºF ambient), all generation dispatched to full, and all purchases modeled (including SEPA allocation to SMEPA).

Generation Resources and Interchange

Generation resources on the PowerSouth system are typical of the Southeast area (coal & gas fired) with four main plants totaling 1666 MW of summer capacity. The plants are Lowman, Vann, McIntosh and McWilliams. PowerSouth also has a 8.16% ownership in the APCo Miller generating plant units 1&2 and two small hydros. For the purposes of this study, all units were economically dispatched. PowerSouth generators are always modeled with real and reactive components. These values are based on the generator capability curve for each unit. The PowerSouth hydros were not considered to be a resource since water may not be available and because the available nameplate capacity is low.

PowerSouth's bulk transmission system has ties to Southern Company at the 115kV and 230 kV levels and with SMEPA at the 230 kV voltage level. These ties to other transmission systems provide a benefit to both parties by allowing purchase and sales of energy across these ties. These ties have the effect of increasing the reliability of both parties. Tie lines are analyzed in the annual assessment in the same manner as integrated lines.

Generation resources and purchases and sales are accounted for in the Area Interchange Spreadsheet. This spreadsheet lists all load (on and off system plus losses), purchases, sales and PowerSouth owned generation. The net result of this spreadsheet is the Area Interchange. This load, losses, generation, and interchange is calculated for each study year and season to be used in the PSSE model.

Load Forecast

PowerSouth's demand and energy forecasts are based on weather and economic conditions that are used in the modeling process. There is a degree of uncertainty associated with these factors. The "Most Probable" scenario, otherwise referred to as a "50/50" probabilistic forecast method, is developed using normal weather conditions and normal economic factors (consumer growth and per capita real income). Historical demand is used to allocate the projected non-coincident peak (NCP) demand from the energy models of the individual member systems to their substation level. Member systems power factors are applied at the substation level to convert from MW to MVA. Additionally, coincidence factors are applied to the individual delivery point peak demands to arrive at a coincident peak load flow model. The application of coincidence factors ensures that the energy and demand models concur.

Existing and Planned Facilities

The models that are developed include both existing and planned facilities through the study period. This is true for the SOCO Base case working group as well as the SERC region. Each entity which participates provides their planned facilities. PowerSouth includes within the model all transmission projects and generator additions that are currently approved for construction.

Planning Criteria

The evaluation of power flows and steady state voltages are the normal means by which the system is evaluated for deficiencies. PowerSouth's transmission planning criteria for voltage and thermal analysis is as follows:

PowerSouth has established normal and emergency thermal limits (MVA) for each facility based upon the Facilities Rating Methodology document. The PSSE model reflects the most limiting element from the asset database which means that in some cases, the full rating of a transmission line may not be realized because of a switch rating (or other limiting element). A facility will be overloaded when the MVA flow exceeds the applicable rating.

Based on this rating, each element is evaluated according to the NERC Category. It is recognized that equipment may be operated above its "normal" rating for short durations for example when implementing operating guides or system reconfigurations.

Maintenance and Other Planned Outages

PowerSouth does not plan for maintenance during peak times. Therefore, maintenance outages are taken into account in light load cases. In these cases, the largest unit in a geographic location is outaged to evaluate the worst case. Smaller generators will produce less severe results. Maintenance outages or extended outages of generators, transmission lines, bulk power transformers and other elements are accounted for in the base case creation process. Select generating units are always shown outaged for maintenance in a light load case. Other elements, such as transmission lines and transformers are outaged if known in advance.

Eastern Interconnection Planning Collaborative

Progress Energy – Carolinas

Progress Energy Carolinas (PEC) transmission planning is a continuous process and covers the 10 years of the planning horizon. The process determines the necessary enhancements to the existing transmission system to meet several objectives. The first objective is to provide an adequate transmission system to serve the network load of the Progress Energy Carolinas service territory. The second objective is to maintain adequate transmission thermal capacity and reactive power reserves (in the generation and transmission systems) to accommodate scheduled and credible unscheduled transmission and generation contingencies. PEC also maintains compliance with approved NERC Reliability Standards and adheres to all other applicable regulatory requirements. PEC provides comparable service under its FERC Open Access Transmission Tariff (OATT) while satisfying contractual commitments and other operating requirements.

Transmission planning uses MMWG models which are further modified in collaboration with SERC members to provide updated information for the SERC region. PEC's data is consistent with the following items:

1) Resource information required annually from load serving entities under the PEC OATT. The information identifies the on and off system resources that are expected to meet each LSE's load forecast over the planning horizon. New generation with a signed interconnection agreement and firm transmission service is included in the models. All OATT annual or longer firm transmission service confirmed by PEC's customers.

2) Transmission facilities that are approved & budgeted or where construction has begun are included in the models. Other projects the planners believe have a high certainty of being in service in the year being modeled are also included. Engineering judgment is applied such that a new or upgraded facility that is marginally needed may not be included in the base model so that the timing of the need for the facility can be accurately determined.

3) PEC's Annual Plan filings provided to the NC and SC utilities commission's which identify PEC's integrated resource plan.

PEC's transmission expansion plan is the compilation of transmission facility improvements and upgrades which are necessary for the transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC Reliability standards. The expansion plan is based on information obtained through PEC's internal planning efforts as well as through the SERC Long Term Study Group, North Carolina Transmission Planning Collaborative, Southeastern Inter-Regional Participation Process, and joint studies with interconnected neighbors.

Progress Energy – Florida

Included as part of Florida Power and Light.

South Carolina Electric & Gas

South Carolina Electric and Gas transmission planning is a continuous process including near term (years 1-5) and long term (years 6-10) planning.

SCE&G models are developed using the following criteria:

1. Current system topology
    - The system topology includes all existing transmission and generation elements.
2. Planned transmission expansion
    - Transmission expansion is based on SCE&G's FERC TPL analysis, near term reliability studies, long term future year assessments and many internal analyses while always using the most economic solution.
3. Planned generation resources
    - SCE&G's system load, firm transmission service, Load Serving Entities and reliability agreements are used to determine generation expansion
4. Load forecast assumptions
    - SCE&G uses data from historical loads, corporate forecasted loads, Load Serving Entities and industrial customer forecast to generate a 90/10 load forecast.

SCE&G fully participates in the SERC LTSG and the MMWG processes to coordinate all interconnections with neighboring utilities.

Santee Cooper

Santee Cooper's transmission planning is a yearly, continuous process and is based on a rolling 10-year cycle, in which needed enhancements to the existing transmission system are identified for the next 10 years.

The expansion of the transmission system is based on MMWG models which are further modified to include the latest updates on:

1) resource assumptions that are provided by Santee Cooper's resource planning group and are a product of the IRP/RFP processes
2) load forecast assumptions provided by the Santee Cooper's load forecasting group
3) all firm transmission services accepted by Santee Cooper's transmission customers

Santee Cooper's 10-year Transmission Expansion Plan is the compilation of transmission facility improvements and upgrades which are necessary for the Santee Cooper transmission system to support the proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with NERC TPL standards.

Transmission facilities that are approved & budgeted or where construction has begun are included in the models. Other projects the planners believe have a high degree of confidence of being in service in the year being modeled are also included. Transmission projects associated with resource additions are added to the models in the year the resource is added to the model. Engineering judgment is applied such that a new or upgraded facility that is marginally needed may not be included in the base model so that the timing of the need for the facility can be refined through coordinated planning processes.

Southern Company

The transmission expansion planning process for the Southern Balancing Authority ("SBA") Area is a continuous process. This process identifies potential constraints and the corresponding transmission system enhancements to alleviate these potential constraints in order to meet the projected load forecasts and resource assumptions of the Load Serving Entities ("LSE") within the SBA, as well as, accommodate other long term firm transmission service procured under the Southern Companies' Open Access Transmission Tariff ("OATT"). In general, resource assumptions provided by the LSE represent decisions made as part of state sponsored/regulated Request for Proposals ("RFPs") which are part of the Integrated Resource Planning ("IRP") process. Any resources represented not otherwise under state certification are provided as the LSE "best-guess" resource.

In order to create the transmission models, or base cases, utilized in the transmission planning process, data inputs from the various LSEs and OATT customers within the SBA are provided to the transmission planner for the next ten years. It is worth noting that the transmission planning conducted is not resource planning. Resource planning provides an assessment of load requirements and potential resource options. Resource planning requires extensive cost assumptions regarding resource options, future fuel forecasts, environmental costs, and other parameters. Load forecasts and resource decisions are inputs to the transmission planning process submitted by the LSEs and OATT customers within the SBA. For example, the transmission planner supports the resource planning processes by providing assessments of the transmission needs and costs associated with various resource options, but the cost analysis of technology options and ultimate resource decisions are made by the LSE, not the transmission planner. As such, resource and load decisions (whether for retail native load or for wholesale customers under the Tariff) become inputs to the transmission planning process.

The transmission expansion planning process begins each year with the most recently completed Eastern Interconnection Reliability Assessment Group ("ERAG") Multi-Regional Modeling Working Group ("MMWG") set of models. The transmission planner then updates the MMWG models with the latest assumptions and the most current transmission expansion plan that was produced in the previous year's process. The transmission planner utilizes the MMWG models as the starting point to build an extensive library of models to be utilized in the transmission planning process. This library consists of models extending through the next ten years for multiple load levels, including but not limited to: Summer Peak, Winter Peak, Spring Peak, and Light Load.

Once the models are developed, transmission planners begin re-evaluating the latest transmission expansion plan produced by the previous year's process with the latest assumptions. Analysis of the transmission system is intended to determine if the existing transmission expansion plan and the associated timing of such plan is adequate. Through the analyses process, transmission enhancements will be added/removed/re-timed as necessary. These analyses are performed in accordance with the applicable NERC reliability standards.

Specific information on the current transmission expansion plan can be found on the Southeastern Regional Transmission Planning website at: (http://www.southeasternrtp.com/).

Southwest Power Pool

SPP's Modeling Group produces a set of base planning models each year. These are identified as MDWG models and are those required by NERC TPL reliability planning standards, encompassing both near-term and longer term transmission planning horizon. These models include:

- Resource and load forecast assumptions provided by SPP LSE's
- Planned reliability upgrades required to meet NERC TPL Planning standards
- Transmission Service upgrades for sold long term firm service
- Generation Interconnection Service upgrades with a signed agreement

The MDWG models and assumption are included in the EIPC roll-up 2020 Summer Case.

SPP's Transmission Planning Group provides further planning of the transmission system based on the MDWG models. This planning effort identifies future project that will enhance SPP's transmission system.

Eastern Interconnection Planning Collaborative

Tennessee Valley Authority

The transmission expansion planning process for the Tennessee Valley Authority (TVA) Balancing Authority (BA) Area is an annual process. This process identifies potential constraints and the corresponding transmission system enhancements to alleviate these potential constraints in order to meet the projected load forecasts within the TVA BA, as well as, other projected transmission usages of transmission customers under the tariff of the TVA transmission service provider (TSP) within the TVA BA.

In order to create the transmission models, or base cases, utilized in the transmission planning process, TVA transmission planning requests data inputs from TVA's resource planning group, TVA's load forecasting group, and other utilities that have network load in the TVA BA. TVA's load forecasting group provides updates to their load forecasts while TVA's resource planning group provides resource assumptions for the next ten years. Resource planning provides an assessment of load requirements and potential resource options. Resource planning requires extensive cost assumptions regarding resource options, future fuel forecasts, environmental costs, and other parameters. Load forecasts and resource decisions are inputs to the transmission planning process submitted by TVA's resource planning group, TVA's load forecasting group, and other utilities that have network load in the TVA BA. The transmission planner supports the resource planning processes by providing assessments of the transmission needs and costs associated with various resource options, but the cost analysis of technology options and ultimate resource decisions are made by TVA's resource planning group through a transparent comprehensive integrated resource planning process, and not by the transmission planner. As such, resource and load decisions become inputs to the transmission planning process.

The transmission expansion planning process begins each year with the most recently completed SERC Long-Term Study Group ("LTSG") or the Eastern Interconnection Reliability Assessment Group ("ERAG") Multi-Regional Modeling Working Group ("MMWG"). TVA transmission planning then updates these models with the latest assumptions provided by TVA's resource planning group, TVA's load forecasting group, and the most current transmission expansion plan that was produced in the previous year's process. TVA transmission planning utilizes the LTSG or MMWG models as the starting point to build an extensive library of models to be utilized in TVA's transmission planning process. This library consists of models extending through the next ten years for multiple load levels, including but not limited to: Summer Peak, Winter Peak, Summer Shoulder, Spring Peak, and Light Load.

Once the models are developed, TVA transmission planning begins re-evaluating the latest transmission expansion plan produced by the previous year's process with the latest assumptions provided by TVA's resource planning group and TVA's load forecasting group. TVA transmission planning will then engage in analysis of the transmission system in order to determine if the existing transmission expansion plan and the associated timing of such plan are adequate. Through the analyses process, transmission enhancements will be added/removed/re-timed as necessary. These analyses are performed in accordance with TVA's planning criteria and the applicable NERC reliability standards. Additionally, as part of this analysis, TVA transmission planning proactively considers not only impacts to TVA's BA, but also to the adjacent Planning Authorities (PA) through the various vehicles available. These vehicles include bi-lateral reliability agreements, study groups that encompass the entire SERC Reliability Region and the various regional planning processes. Results of these studies/analyses are then used as valuable information when determining modifications to TVA's transmission expansion plan to ensure compatibility with the transmission expansion plans of neighboring PAs.

The TVA BA 10-year Transmission Expansion Plan is the compilation of new transmission facilities and upgrades to existing transmission facilities which are necessary for the TVA BA to support proposed resource assumptions, load forecasts, and firm transmission service requirements for the next 10 years in the most reliable and economic manner consistent with TVA's planning criteria and the NERC reliability standards.

Information on TVA's planning processes and the 10-year expansion plan for the TVA BA can be found on TVA's OASIS website (http://www.oatioasis.com/tva/tva_plan.htm).