

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

**GEORGIA POWER COMPANY
DOCKET NO. 42310**

**AFFIDAVIT AND BASIS FOR THE ASSERTION THAT PORTIONS OF THE
INFORMATION SUBMITTED ARE PROTECTED TRADE SECRETS**

As part of its 2019 Integrated Resource Plan and Application for Certification of Capacity from Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 ("2019 IRP"), filed in Docket No. 42310, Georgia Power Company ("Georgia Power" or the "Company") submits to the Georgia Public Service Commission Technical Appendix Volume 3, which contains confidential details regarding current and future transmission projects (the "Information") that is a trade secret of Georgia Power and Southern Company and their affiliates.

The Information derives economic value from not being generally known to, and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Specifically, the Information contains competitively sensitive cost information related to the prices Georgia Power has estimated for transmission equipment and specific details related to the Company's transmission infrastructure. Public dissemination of the Information would allow Georgia Power's competitors and suppliers to have access to the costs paid by the Company and insight into the Company's transmission planning process. Access to the Information would also allow competitors to gain specific insight into the Company's technical analysis regarding planned projects. Competitors would obtain an unfair advantage because they are not required to reveal similar information and can structure the pricing for competing products based on the Information. In the event the Information was released, it is quite likely that suppliers would use the Information to set the floor in establishing their own prices, thus artificially and inefficiently setting a market price that may not be representative of the best cost that the market could offer. Competitors would also unfairly benefit in having access and insight into the Company's planning processes and methodologies. This competitive advantage for the Company's suppliers and competitors would mean that Georgia Power will potentially pay higher prices to suppliers, ultimately harming Georgia Power. Finally, the Information includes details concerning Georgia Power's transmission infrastructure that may be used to pin-point vulnerabilities in the transmission system. Such portions of the Information contain Critical Energy Infrastructure Information, the distribution of which is subject to regulation under the Code of Federal Regulations Section 388.113.

Additionally, the Information is subject to substantial procedures to maintain its secrecy. Only select Georgia Power and Southern Company affiliate personnel are granted access to the Information. Those personnel receive access on a "need to know" basis only. Any parties outside the Company who would be granted access to the Information would be required to sign confidentiality agreements.

Jeffrey R. Grubb, first being duly sworn, deposes and states that he has reviewed Technical Appendix Volume 3 of the Company's 2019 IRP and that to the best of his knowledge the specific information designated as trade secret constitute trade secrets in accordance with O.C.G.A. § 10-1-761 (2018).



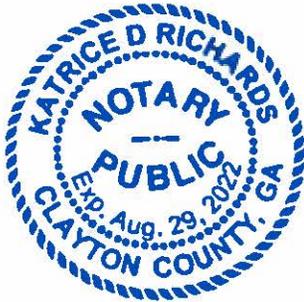
Jeffrey R. Grubb
Director, Resource Policy & Planning
Georgia Power Company

Subscribed and sworn to before me this 16th day of January, 2019.



Notary Public

My Commission expires:



2019 IRP
TECHNICAL APPENDIX
VOLUME 3
TRANSMISSION PLAN

**TECHNICAL APPENDIX
VOLUME 3
INDEX**

- A) Transmission Planning Description and Process**
 - 1) General Description**
 - 2) Transmission Planning Principles**
 - 3) Planning Model**
 - 4) Transmission System Evaluation**
 - 5) Planning Coordination with the ITS**
 - 6) Project Determination and Documentation**
 - a) Strategy**
 - b) Developing Tentative Solutions**
 - c) Feasibility Analysis**
 - d) Project Evaluation**
 - e) Recommendation - Project Documentation**
 - 7) Budgeting**
 - a) Presentation and Approval**
 - b) Inclusion in Capital Budget**
 - c) Budgetary Review and Control**
 - 8) Transmission Planning Tools**
 - 9) Guidelines**
 - 10) Process Flow Diagram**
- B) Transmission Planning Guidelines**
 - 1) NERC / SERC Reliability Standards Summary**
 - 2) Georgia ITS Planning Guidelines**
 - 3) Bulk Power Transformer Loading Guide**
- C) Transmission System Operations**
 - 1) 2018 Summer Operating Study**
 - 2) 2016-2018 System Performance**

D) Georgia ITS

1) 10 Year Expansion Plan

Executive Summary and Projects List

Transmission Planning Process Description

Performance Criteria

10 Year Plan Projects (Analysis Results)

2) ITS Loss Study

E) Interface and Interconnections

1) Regional Transmission Planning

2) Transmission Service Request Summary

3) Southern Company Electric System Interface Analysis

4) Optimum Transmission Sites for Generation

F) GPC Distribution Substation Projects & Forecast (Five Year Loading Plan)

G) Budgeting

1) T&D Average Incremental Cost Overview

2) Budgeting & Budget Control

3) Power Delivery Capacity Addition Expansion Plan

4) Approved Projects (BCAs with Documentation – CDs)

H) Appendix

1) Identified Problems & Solutions

a) Thermal Problems & Solutions

b) Voltage Problems & Solutions

2) Load Flow Data Files (CDs)

3) Region / ITS Maps

4) Acronyms & Technical Definitions

FOREWORD

The documents presented in this volume of the IRP Technical Appendices represent a snapshot of Georgia Power Company's transmission and distribution (T&D) plan, as of December 2018. As new developments occur, the plan will be revised as necessary in accordance with the planning procedures these documents describe and other actions directed by the Company's management. Actions may be driven by factors such as: economic conditions, customer needs, regulatory changes, etc.

As discussed in Chapter 2 of the IRP Main Document, the Company included Gulf Power Company (Gulf Power) and its service territory in Florida in the information compiled and analysis completed for Technical Appendix Volume 3 in a manner consistent with past IRPs.

[A]

**TRANSMISSION PLANNING
DESCRIPTION
&
PROCESS**

1. GENERAL DESCRIPTION

The Integrated Transmission System (ITS) consists of the physical equipment necessary to transmit power from the generating plants and interconnection points to the local area distribution load centers. The ITS consists of electric transmission facilities (>40kV) that are individually owned and maintained by Georgia Power Company (GPC), Georgia Transmission Corporation (GTC), MEAG Power (MEAG) and Dalton Utilities (DU) (i.e. the ITS Participants). Transmission planning embodies investment decisions required to maintain sufficient capacity in the ITS to reliably meet the power needs of the public. Justifications for these decisions are based on technical and economic evaluations of options that may be implemented to meet these needs. Under the ITS Agreements, the ITS Participants are responsible for meeting their full load requirements, including generation, and are responsible for making improvements to their facilities to accommodate transmission improvements required by load growth or system reliability.

As of December 31, 2017, Georgia Power's transmission system consisted of 46kV (2,900 miles), 69kV (139 miles), 115kV (5,935 miles), 230kV (2,523 miles), and 500kV (1,166 miles) lines totaling approximately 12,437 miles. This transmission system, along with other ITS transmission facilities, connected approximately 15,274 MW of GPC-owned, installed generating capacity. The total GPC residential, commercial, and industrial peak demand served in 2018 was approximately 15,747 MW.

GPC is a member of the Southern Company Electric System (SCES), one of the largest interconnected systems in the United States. The SCES includes portions of the states of Georgia, Alabama, Mississippi and Florida. In addition, the SCES is a member of the SERC Reliability Corporation (SERC), one of eight regional entities of the North American Electric Reliability Corporation (NERC).

Transmission Planning-East (TP-E) of Southern Company Services (SCS) and Power Delivery System Performance of GPC, with input from Power Delivery Operations of GPC, are responsible for planning the transmission system for GPC. TP-E develops a planning model of the transmission system for each year for ten years into the future. This

planning model is used to identify transmission problems and to evaluate alternative solutions to those problems.

NERC has established national planning standards for the electric utility industry. These standards provide consistency in planning. In addition, each utility has its own practices and requirements. The Guidelines for Planning the Georgia Integrated Transmission System and the Guidelines for Planning the Southern Company Electric Transmission System are consistent with the NERC Reliability Standards.

Some interchange contract requirements must also be considered in the planning of the ITS. GPC, Southern Company (SoCo), and Oglethorpe Power Corporation (OPC) have interchange and reliability agreements with other systems such as Duke Power, South Carolina Electric and Gas (SCEG), Tennessee Valley Authority (TVA), and the Florida utilities. Examples of these contracts are:

1. Interchange agreement between TVA and GPC
2. The contract executed by the United States of America Department of the Interior acting by and through the Southeastern Power Administration (SEPA) and GPC
3. The Inter-company Interchange Contract (IIC) among the Southern Company member companies; and Block wholesale contracts
4. In addition, there are contracts with large customers pertaining to quality of service or co-generation.

2. TRANSMISSION PLANNING PRINCIPLES

The principles that apply to Georgia's transmission planning are:

1. Identify and recommend projects that are consistent with the Guidelines for Planning the ITS and the Guidelines for Planning the Southern Company Electric Transmission System.
2. Identify and recommend projects that are consistent with the NERC Reliability Standards.
3. Minimize costs associated with the transmission system expansion, considering the impact to system reliability.
4. Identify projects with sufficient lead-time to provide for the timely construction of new transmission facilities.
5. Coordinate transmission system plans with the plans developed by the GPC Power Delivery Planning groups.
6. Coordinate transmission system plans with all ITS Participants and other transmission owners to enhance reliability and minimize associated costs.
7. Coordinate future transmission plans with other GPC departments, other ITS Participants, other SCS departments and the regions surrounding the Southeast in the project development and planning processes.
8. Maintain adequate interconnections with neighboring utilities.
9. Communicate with GPC management to ensure proper awareness of the importance of adequate transmission improvements and system expansion.
10. Utilize existing resources (for example, reusing rights of way, implementing voltage conversions, constructing double-circuit lines) where feasible.
11. Minimize transmission losses when cost effective.
12. Avoid the loss of life to transmission equipment from forced operation at higher loading levels.

These principles provide guidance to Transmission planners and/or planning authorities that are called upon to explore existing issues and any future problems encountered in the transmission planning process.

3. PLANNING MODEL

The transmission system is modeled mathematically to simulate the characteristics and operation of the actual electric power system under any given set of conditions. This system model is evaluated under a variety of conditions to reveal problems created by the anticipated growth of the system and related power transfers. These problems are evident when the performance of the model (system) is determined to be below an acceptable standard. The model is then studied to determine the causes of these problems. Changes are made to the model which solve these problems in varying degrees, and, from this, solutions are developed. The most widely accepted models are the load flow model and the stability model.

These solutions, which take the form of improvements to be made to the actual system or temporary operating guidelines, are examined in relation to the system. The infeasible solutions are eliminated, and those remaining are evaluated as to benefit and cost. The recommended solutions are those that best fit the system financially, electrically and physically. Funds are allocated to implement the proposed improvements through the Capital Budget.

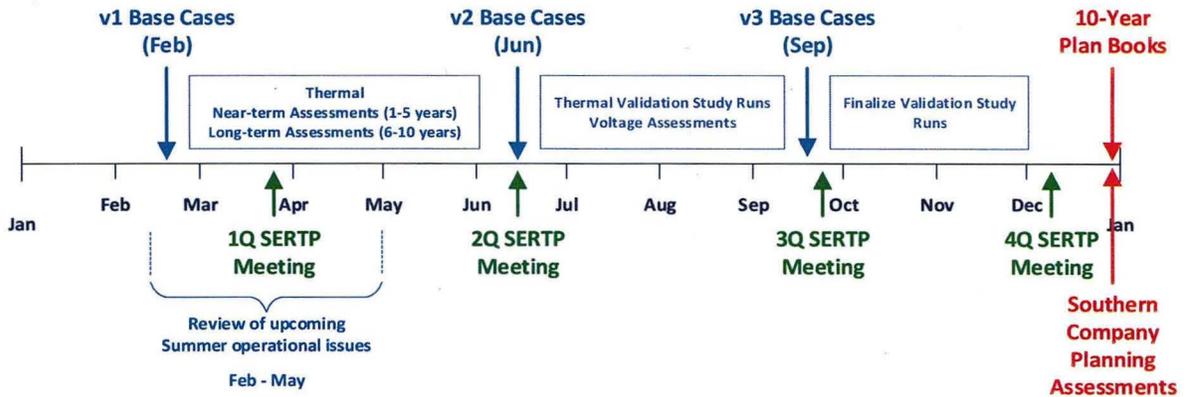
Coordination of the planned system improvements by all ITS Participants must be accomplished and included in the system model.

LOAD FLOW

The load flow model is used to study the steady state response of the transmission network when supplying the real and reactive load requirements from the generation sources and non-territorial suppliers. Using this model, all real and reactive power flows and the magnitude and phase angle of all system voltages can be calculated. Given reliable input data, the load flow is a highly accurate model. Because of its accuracy and varied applications, the load flow model can be considered the "cornerstone" of the transmission planning process. Among its applications are:

1. The selection of the most economic operation of generators;
2. The study of disturbances or outages;
3. The planning for additions or expansions;
4. The evaluation of system performance; and
5. Inertial response to disturbance.

A base case load flow is a load flow model for a specified future date. This model incorporates the existing system and all planned additions to the system up to the specified date. For example, the 2018 Base Case is a load flow model for the summer coincident peak hour of 2018. It includes all transmission projects that have been or will be completed by May 1, 2018. The model incorporates load forecast estimates and the anticipated generation expansion plan. In addition, through communication with neighboring systems, necessary outside system models are created. Base case load flow models are created for the current year (“Year 0”, used mainly by Operations) and each of the next ten years into the future, used by Transmission Planning.



Typical Base Case Release and Study Schedule

A base case load flow building process begins with the compilation of all data required to formulate load flow representations for a ten-year forecast period. Included in this database are:

1. A system peak load forecast by the ITS Participants,
2. A generation expansion plan by the ITS Participants,
3. Transmission line, transformer, and capacity data,
4. An interchange schedule,
5. Equivalent network data for adjacent systems, and
6. Budgeted project data.

The changes made in the Fall revision of the GPC Capital Budget are used to update the next series of transmission base cases. These changes along with other factors can influence the project plans within the ten-year forecast period. Some of these additional factors are listed below as examples and include company- or area-specific impacts as well as external utility and industry impacts:

- Changes in load forecast,
- Changes in generation resources and patterns,
- Changes in loop flows caused by transactions between neighboring utilities,
- Additional projects that are driven by changing economic activity,
- Increasing equipment and labor costs, and
- Changing regulatory requirements.

In summary, the load flow building process results in a set of base cases which accurately reflect the approved budget projects in concert with the approved generation expansion plan and system load forecast. Load flow cases are used to study the proposed transmission systems under both normal operating and contingency conditions.

STABILITY

In contrast to the load flow model that deals in the steady-state mode, the stability model is concerned with solutions in the transient and dynamic mode. The transient stability model is used primarily to provide information on the capability of the power system to remain in synchronism during and immediately following a major disturbance, such as a short circuit. The period of time involved in this type of scenario is approximately one second following a system disturbance and prior to governor action at the generator. Dynamic stability analysis studies a period of up to 20 seconds after a system disturbance. A system is said to be stable, due to inertial accelerating forces, if an acceptable balance between generation and load is maintained. A stable system will remain in synchronism even though individual machines may become unstable and trip. Post dynamic stability conditions are studied with the load flow model.

The stability model requires a solved load flow case to specify initial power flows and system voltages. The main elements of the stability model are generation, load, and transmission. The generation element includes machine characteristics and impedances, including the impedances of the main power transformers, and characteristics of turbine, governor and excitation. In addition, some machine characteristics may be necessary for large generators in neighboring systems. In the stability analysis the loads, as represented in the load flow, are typically identified as being of the following types: constant current, constant impedance, or constant MVA. The positive sequence impedances of the transmission lines and transformers are provided by the load flow case.

Beginning with the load flow representation and incorporating any additional data requirements, the transient stability problem can be investigated for each machine. Swing curves, indicating the relative angular displacements of machines under fault conditions, are used to determine the stability condition of the system. A system is judged to be stable if the relative angles between machines do not increase without bound.

4. TRANSMISSION SYSTEM EVALUATION

After the System Model is complete, the transmission system is screened for thermal and voltage problems. This screen is based on the Guidelines for Planning the Georgia Integrated Transmission System.

In evaluating the proposed transmission systems, as modeled by the load flow base cases, the transmission planners are concerned with:

1. What are the operating or contingency conditions that may stress the transmission system?
2. In what portions of the system do these stress situations develop?
3. What are the underlying issues indicated by the symptoms of low voltages or overloaded lines and transformers?

Transmission planning studies generally break down into three broad areas of responsibility:

1. Generator connections,
2. Bulk power transmission, and
3. Region/area transmission.

Generator connections refer to those transmission elements necessary to tie a proposed generating plant into the existing transmission system. These elements include a loop-in of an existing transmission line, construction of a new line, or any necessary 500/230-kV or 230/115-kV transformers. The concern in bulk power studies is the performance of the 500-kV and 230-kV network in efficiently transferring power from the generators to the load centers, under both summer and winter conditions. For studies of generator connections and the bulk power system, stability and adequate transmission capacity are the prime considerations. At the regional/area levels, the primary concerns are adequate voltage support and line capacity to serve the load areas.

Using the load flow base cases, the transmission planners analyze the ability of the transmission system to operate under normal and contingency conditions. Next, the

planners consider the sensitivity of the system to variations in load level or generation dispatch level.

Evaluation of the transmission system under normal conditions requires that all facilities operate within normal thermal ratings, with all lines, transformers, and generators in service. Normal base case conditions assume an economic dispatch of all SCES, OPC, MEAG, and Dalton units to match the transmission system peak load forecast. Under normal peak operating conditions, the bulk power system should provide flexible and reliable operation of all generating units. By creating "unit-off" load flow base cases, the transmission planners investigate the effects of generator unit delays or forced outages on the normal transmission system.

Base cases are developed to model flows that result from known contract obligations to supply power through an interchange. The needs of the importing companies may stem from generator forced outages, faults on major transmission facilities or unforeseen generation shortfalls.

Contingency analysis covers the consequences of the unexpected loss of transmission facilities and/or generating units. Contingency evaluations are performed primarily under peak load conditions. Some off-peak studies may be necessary when there is reason to suspect that voltage problems, thermal overloads, or instability may occur.

In performing load flow planning studies, the sensitivity of the proposed transmission system to load and generation changes is considered. If the load forecast or the generation expansion plan change, the level of planned investment in new transmission facilities may change.

The transmission planners use the load flow and transient stability program to test generator connections and to analyze potential problems. It is in this study area that a detailed representation of both the generator and each major transmission line is employed. The goal is to maintain the integrity of the generating units under both fault and no-fault conditions. The most serious fault condition is that of a simultaneous fault on

all three phases of a transmission line. Other faults that deserve review are those of single phase to ground and two phases to ground.

Overloads on transmission lines cause reduction of sag clearances due to excessive conductor heating. Line loadings up to the design rating are maintained without damaging line conductors or exceeding code clearances. Transformer ratings consider the rise in temperature of the oil used for transformer cooling, with some loss of life assumed for operation above nameplate.

Generator voltage schedules in load flow analysis reflect the actual generator schedules used in operating the system. Adjustments to the voltage schedules become necessary in load flow cases representing later years.

Short circuit studies are performed on the projected system under normal conditions. Problems occur under fault conditions at generating plants and other substations when exposure to fault current overstresses the substation equipment. For this reason, all 500-kV, 230-kV, and 115-kV circuit breakers at generating plants, switching stations, and 500/230-kV or 230/115-kV substations are rated higher than the maximum available fault current that might be encountered at these locations. In conjunction with the SCS Protection & Control Engineering section, the transmission planners commonly use the short circuit and breaker duty information to provide for the timely replacement of overstressed equipment and for the proper sizing of new equipment.

Inertial studies are conducted on the transmission system. These studies involve examining the effects on the transmission network of losing a major generating facility within the system and in systems tied to the ITS. The sudden deficit of hundreds of MW of power causes the transmission network surrounding the lost generation facility to supply the deficit before remedial action can take place. Inertial studies are undertaken to spot and solve any problems that might develop.

5. PLANNING COORDINATION WITH THE ITS

Planning for the ITS is a coordinated effort among the four ITS Participants. Interaction between GPC/SCS and the other Participants takes place at many points throughout the year in the annual planning process (see the timeline in Section A), including the following:

1. Throughout the year (starting with the previous year's summer peak load hour), each ITS Participant provides data for creating planning model base cases.
 - a. Each ITS Participant provides for each substation that it owns: historical loads; expected future growth rates, load additions, and shifts to and from other substations; location, in-service dates and connection details for any new substations it is planning; generation expansion plan and new interconnection agreements; and timing, source/sink, and MW amount of any firm interchange contracts into which it has entered. This data is compiled by SCS into the planning model base cases used by all ITS Participants.
 - b. "Beta" versions of the planning model base cases are provided to the Participants for review and error checking. ITS Participants suggest changes or corrections that need to be made before the final base cases (Versions 1, 2 and 3) are used for screening for thermal and voltage constraints.
 - c. After Version 1 and Version 2 Base Cases are finalized, ITS Participants together review future planned projects that should be "stripped" from the base cases to verify their need and timing. Projects are left in the base cases if they are far enough along in the engineering and construction process, have contracted obligations for specific years, or are tied to certain assumptions (such as improvements associated with new generation). The final Version 3 base cases represent the completed plan, so it is not necessary to strip out projects.

- d. "Stripped" cases are created to conduct screens. These stripped cases are constructed from the base cases with projects stripped, and various generation dispatches and seasonal loads applied. Before screening, GTC and SCS will create the stripped cases independently and will compare their cases to resolve any differences.
2. Throughout the year, screening results are reviewed.
 - a. After the screening is performed, all ITS participants meet to review the thermal and voltage constraints identified in the screens. Solutions for these constraints are agreed upon for inclusion in the Ten Year Plan. These meetings may decide the need for and timing of the simpler projects or may shift the timing of previous projects. For more complex issues, where additional studies are needed or multiple constraints are identified in an area, joint ITS Planning Working Groups are established.
 - b. Over the next several weeks, the ITS planners responsible for the areas where the constraints were identified work together on the best solution to be built into subsequent versions of base cases by the SCS planners.
 3. Each month, representatives of each Participant meet at the Transmission Planning Working Group (TPWG) meeting. At this meeting:
 - a. Each Participant presents new projects. Some of these projects address constraints identified and agreed to by the ITS planners as described above and need to be recommended for approval at a subsequent meeting of the Joint Sub-Committee for Transmission Planning (JSTP). If the JSTP agrees with the recommendation, it will recommend projects for approval and inclusion in ITS investment to the Joint Committee for Planning and Operations (Joint Committee). Other projects, such as capital maintenance or relay projects, are brought to the TPWG for information only.
 - b. The TPWG determines whether a project sponsored by one Participant requires work to be done in another Participant's facility, in which case it will

send a Transmission Improvement Notification (TIN). For example, if GTC rebuilds a transmission line, GPC may need to replace switches or jumpers at a GPC owned substation served by a GTC owned line. In this case, GTC would send GPC a TIN requesting that the work be performed.

- c. Projects that were presented earlier but not yet approved are discussed and potentially approved. These projects may not have been previously approved because one or more of the participants requested more time to review or had additional questions or concerns.
 - d. Projects with scope changes or cost overruns are reviewed.
 - e. Various area studies and initiatives and the status and timing of the overall planning process are discussed.
4. Each month, representatives of each Participant meet at the Interface Working Group (IWG) meeting.
 - a. At this meeting details of the annual interface planning process are discussed. This process includes agreeing on assumptions, performing interface analysis studies, and performing calculations necessary to properly allocate among the Participants the transfer capability between the Southern Company Electric System and neighboring systems that border the ITS.
 5. By the time the Ten Year Plan is published, the Participants provide estimates of the costs of their projects for inclusion in the document.
 6. ITS Participants are invited to participate in an annual presentation given by Transmission Planning-Central, which produces the base cases, explaining the assumptions and providing a chance for feedback.

6. PROJECT DETERMINATION AND DOCUMENTATION

The process of determining a transmission project to solve an identified problem can be broken down into several steps.

6a. STRATEGY

The transmission planning process follows an iterative process with a planning horizon looking 10 years into the future. However, due to the dynamics of the assumptions and data used to develop the latter years of the system model, project proposals are usually developed for the first five years only (considered to be the near-term planning horizon). These projects and their mutual effects are tested throughout the full ten-year period.

Projects that cause the largest changes in the transmission system are studied first. For example, the way a large generating plant is connected to the transmission system is generally felt throughout the system. Conversely, projects involving the 115kV system are felt only in the immediate area of the project. Thus, a general outline of study is:

1. Generation connections,
2. 500kV system,
3. 500/230kV transformer capacity,
4. 230kV system,
5. 230/115kV transformer capacity, and
6. 115kV system.

This process continues in an iterative manner. For example, while the effect of 115kV system improvements upon the 500kV systems may be negligible, the 230kV system changes may influence the 500kV system projects. Similarly, the 115kV system projects may influence the 230kV system projects. This iterative process is performed for each interaction of the ten-year planning horizon.

6b. DEVELOPING TENTATIVE SOLUTIONS

If the thermal and voltage problems identified in the transmission area studies cannot be alleviated with operating guidelines, Transmission Planning determines improvements to the transmission system to correct these problems. Where possible, several options for system improvements are identified and evaluated. The evaluation process optimizes cost, system performance, duration of the fixes, and conformity to the long-range transmission expansion requirements. The results of this process are compiled into a study document.

The input to the project determination process is a problem statement. As noted in earlier sections, these problems are defined by applying performance criteria to the base case models. Built into the base case models is an assumed set of projects, i.e., those proposed by the ITS Participants. Thus, other problems and solutions are a framework against which these problems are being considered.

In addition to simulation of the future transmission system using the base case models, problem statements are also generated by other sources.

1. Providing service to new customers could generate problem statements. Generally, this involves transmission connections for large industrial substations.
2. Timing, size, and location of future generation plants (management decisions) necessitate problem statements related to the provisions of transmission connections to the planned generation plants from the existing transmission system.
3. Management decisions concerning interchange capability with neighboring systems could generate problem statements concerning provisions for the specified transmission capacity.
4. GPC Power Delivery Planning determines future service points for GPC, which leads to problem statements involving transmission capacity to new service points.

5. GPC System Operations will uncover problems that are not routinely studied by TP-E.
6. System enhancements proposed by other ITS Participants will uncover problems in all five areas listed above.

Before tentative solutions are developed, all problems should be fully defined. Certain questions must be answered when defining these problems.

1. Do these problems persist into the future?
2. Do these problems get worse?
3. Are additional problems developing in the area?
4. Is there a more general description of these problems?
5. Are these problems sensitive to load or generation variations?
6. If these problems result from contingency situations, what is the probability of these contingencies occurring and what are the consequences?

As a rule, it is difficult to isolate a single problem. Furthermore, as the study progresses into the later phases of the project determination process, the problems may need to be redefined.

If the problem falls within the near-term planning horizon (within approximately 5 years), Transmission Planning Engineers will host a solution team meeting including representatives from all parties affected by or involved in the process to resolve the identified problem. This meeting usually produces some of the alternatives considered and helps set the scope for the project. After the general scope is identified and once the full ramifications of all problems are understood, possible solutions are formulated. Generally, a finite number of reasonable, but not necessarily feasible, solutions are devised. The Transmission Planning Engineers will evaluate these options based on the aforementioned criteria and using planning-grade estimates for the cost comparisons.

Some examples of the possible solutions considered in the near-term planning process include but are not limited to implementing or modifying an operating guide, upgrading or re-building existing facilities, constructing new facilities, the addition of reactive resources

or current-limiting devices, and the use of non-traditional technologies. The solutions produced from this process ultimately lead to a primary recommendation that represents the best fit to address the problem while also considering cost and other factors as previously described.

There are many ways to address the system needs through the methods previously mentioned. The following list provides examples of system improvements within each of these categories:

- Operating guides – Changing configuration of the system by opening and/or closing switches or through the redispatch of generation to change the flow of power along the transmission lines.
- Upgrading or re-building existing facilities – Upgrading a line currently operated at 75°C so that it can be operated at 100°C, thereby increasing the rating and available capacity of the transmission line.
- Constructing new facilities – Building a new transmission-connected substation can provide additional connectivity options and flexibility for operating the transmission system.
- Addition of reactive resources or current-limiting devices – By adding a capacitor bank, series reactor, or a shunt reactor, the system has more assets to help operators better regulate real and reactive power flow. A reactive resource such as a capacitor bank might be selected if an area suffers from low voltage or a high reactive power requirement, while a current-limiting resource such as a series reactor might be selected if the area suffers from high power flow along a specific path. The addition of reactive resources or current-limiting devices can help reduce or eliminate the need for other transmission projects such as a line facility upgrade.
- Non-traditional technologies – GPC evaluates and installs cost-effective non-traditional technologies as needed to address specific system needs. One such example includes the use of a Static Var Compensator (SVC) to regulate voltage and provide electrical stability to the surrounding network instead of pursuing transmission upgrade projects. In addition, as technology advances and costs for the implementation of battery storage technologies decrease, if load growth is

anticipated in a remote part of the transmission system, the use of battery storage technologies might be selected as an alternative to constructing a new line and/or substation to serve the additional load.

6c. FEASIBILITY ANALYSIS

Feasibility analysis involves testing the solutions devised in the preceding section. This analysis concerns two broad areas:

1. Does the proposed solution solve the problem? (Electrical Feasibility)
2. Can the solution be implemented? (Physical Feasibility)

ELECTRICAL FEASIBILITY

In this activity, the tentative solutions are simulated using the load flow program. The goal is to:

1. Identify proposed solutions that solve the problems and
2. Identify proposed solutions that do not solve the problems.

No solution completely solves the problems indefinitely. Similarly, some solutions may improve the situation without really solving the problems. Solutions that cause more problems than are solved are excluded. Consideration is given to solution effects on the surrounding system. Rejected solutions are documented at this point for inclusion in the Project Documentation stage.

The process of solution feasibility sheds additional light on the nature of the problems. This may cause the problems to be redefined and suggest additional possible solutions. Also, modification of a previous solution may result.

As in the definition of the problem, feasibility testing is performed using load flows. As stated in the previous stage, the base cases contain many assumptions. The transmission planners note the base case assumptions and reflect these in determining the proposed solution feasibility. Also, the criticality and sensitivity of the base case assumptions are tested.

PHYSICAL FEASIBILITY

The determination of physical feasibility is accomplished by consultation with groups outside of TP-E. Among the groups contacted at this stage are:

1. The GPC Land Department and Location Committee (concerning availability of R/W, guying and trimming rights, and substations sites),
2. Engineering (concerning design, protection, control and construction matters),
3. System Operations (concerning protection, control, maintenance, and operating matters), and
4. Region and Transmission & Maintenance Center personnel (since they may have knowledge of all the above items).

Consultation with the above groups occurs on an informal basis or through the formation of "Solution Teams". However, all inputs, decisions, and recommendations contributed by these groups are documented.

6d. PROJECT EVALUATION

INTRODUCTION

The input to this phase is a set of feasible solutions to the problems. Up to this point, only the current problems under study have explicitly been considered. To evaluate any solution properly, all effects are analyzed.

The project selection criteria are centered on economic factors and engineering benefits. Both the economic and engineering analyses include not only the solution alternatives, but also other projects affected by the implementation of each alternative.

As noted previously, the base case load flows contain an assumed set of projects. Until the evaluation stage, this set of solutions remains constant. In evaluating the current project, the base assumptions are allowed to vary.

The base case models contain other assumptions in addition to the assumed set of transmission projects. Additional inputs to the model are:

1. Forecast load totals,
2. Forecast load distribution,
3. Generation expansion plan,
4. Forecast interchange contracts,
5. Equivalents of outside systems, and
6. System improvements by other ITS Participants.

All of the above parameters are subject to change. Likewise, the performance criteria by which the model is tested can change from time to time. Since the model is used to define, test and evaluate proposed projects, any change to the model changes the outcome of the project determination process. As a result, transmission planners evaluate the sensitivity of proposed solutions to changes in the above parameters.

Project determination is an iterative process beginning with problem statements and working through the evaluation steps. At this point, various changes will be made to the projects involved and the base cases updated. Then the same process is repeated. In time, this process will converge on the best solution(s).

Two final notes on the evaluation stage of the project determination process are:

1. For a true economic analysis, the alternatives being considered should result in the same final outcome. However, the initial decision made in transmission system design will determine, to some extent, all subsequent decisions. Thus, non-coincidental projects will tend to make the future systems diverge, i.e., the further out one looks, the less alike the systems become.
2. The evaluation process is a cost/benefit analysis. Costs can be measured with a fair degree of accuracy. Benefits are measured, if they can be measured at all, in other terms. Thus, in comparing alternative projects, the cost/benefit ratio cannot be stated in absolute terms.

BENEFITS OF ALTERNATIVE PROJECTS

1. Solution to problem

For problems to be identified, situations exist where the system will operate in an unacceptable manner (as defined by the performance guidelines). Each of the alternatives should restore the system to an acceptable level. However, there are variations in the adequacy of solution alternatives. In some cases, this variation can be measured. For example, differences in the number of years before other problems develop in the area. In other instances, the adequacy of solutions cannot be quantified. In either case, no absolute measure of solution adequacy exists. Thus, alternatives are ranked as to degree of solution to the problems.

2. Impact on other problems

A benefit of a project is its positive impact on surrounding problems. This impact is measured by summarizing the problems or possible delays in project implementation that are eliminated.

3. Improvement in reliability

The alternatives under consideration result in differing reliability levels. Problems occur in two areas:

- a. loss of load, and
- b. system security.

Loss of load is the loss of service to customers, while system security deals with the integrity of the bulk transmission system.

4. Flexibility with regard to future development

Not all alternatives look the same regarding future development. This flexibility feature is for development beyond the horizon year. Thus, at the time of the study, an identified benefit may not be reflected in the analysis. Additionally,

system voltage levels are constantly being upgraded. Provisions for this are made, even if the need to raise operating voltages in an area has not been determined.

5. Ease of operation

This benefit refers to operating simplicity. Desirable features for an alternative are:

- a. standard switching procedures,
- b. supervisory control, and
- c. easy access to switching points.

6. Improvement in stability

This benefit is not directly measurable. All alternatives must be stable to be feasible. However, one alternative may provide greater stability than another under contingency situations.

7. Increase interchange capability

This benefit is measurable. It is generally desirable to increase interchange capability. Beyond a certain point, however, increasing the interchange capability becomes less beneficial. Thus, this benefit is in part determined by the interchange levels required to maintain adequate reliability.

8. Ease of protection

This benefit is not directly measurable. As with stability, an alternative must be protected to some minimum standard to be considered feasible. However, there are differing degrees of acceptability of the alternatives. Features such as the magnitude of the available fault currents, the existing stress on circuit breakers, the ability to utilize standard relays and procedures, and the flexibility of protective schemes vary among alternatives.

9. Environmental factors

This benefit is not directly measurable. Some environmental benefits are reflected in the right-of-way or guying and trimming costs of the various alternatives. Also, construction duration times may reflect environmental factors. Additionally, public “good will” towards the Company may differ depending on which alternative is selected.

ECONOMIC EVALUATION

All projects are economically evaluated. However, some projects require extensive analysis. When required, an economic analysis program is used to calculate the revenue requirements for each alternative. The program calculates the levelized annual cost of each alternative utilizing the revenue requirements of the facility over the useful life of the equipment, approximately 40 years. Factors such as the cost of capital, depreciation, and taxes are the major components in determining the revenue requirements. The present-worth of the levelized annual cost is then calculated at the current discount rate.

Construction costs are estimated by the Land and Engineering Departments from requests generated by transmission planners when project proposals are entered into the Transmission Evaluation and Management System (TEAMS). TEAMS is a computer-based program used to initiate project estimates. The program is also used to enter, track and revise projects.

The effects on adjacent study boundary projects are reflected in the analysis. Alternative proposals to the problems currently under study include both positive and negative cost impacts on the study boundary projects. These impacts appear in the form of inclusion of the affected projects in the cost analysis. The affected projects are handled in the same manner as the current project under study.

6e. RECOMMENDATION - PROJECT DOCUMENTATION

From the evaluation, a decision is reached as to which solution should be recommended. Documentation of the recommendation for major projects includes:

1. Management Summary

This section of the project documentation summarizes the problem and the proposed solution.

2. Assumption

A list of the assumptions used in the project evaluation process.

3. Problem Statement

This section of the project documentation includes a full statement of the problems. Included will be the conditions under which the problem occurs. Loads, adjoining problems, and any other information necessary to adequately show the need for the project is also included in the Problem Statement.

4. Discussion of Alternative Plans

This section of the project documentation contains a discussion of the alternatives considered. It summarizes the analysis techniques used and the results obtained including the economic analysis.

5. Recommendation

Statement of recommendation on the preferred plan.

6. Appendix

This section contains the detailed information summarized in the previous section. Such things as load flow plots, economic analysis printouts, correspondence, estimates, etc. are included.

This document is prepared for each special Budget Plant Expenditure (PE) just prior to the approval of the project for construction. In addition, transmission system projects involving GPC facilities that are required due to other ITS Participants' system improvements or load serving requirements are included in the capital budget.

7. BUDGETING

Although the transmission system is studied over a ten-year period, the data and assumptions used to construct the last five years of the system model are typically too fluid to develop firm system expansion plans. Some of the uncertainties associated with these projections are: 1) load growth patterns, 2) generation dispatch, 3) interchange, 4) governmental regulations, 5) capital availability, and 6) needs of other ITS Participants. The budgeting process includes budgeting for five years of approved and forecasted improvements to allow for more efficient utilization of resources and equipment. This five-year budget provides SCS Supply Chain Management sufficient advance notice for ordering major equipment.

7a. PRESENTATION AND APPROVAL

Following the development of a proposed project, the recommendation and accompanying documentation are presented to TP-E Management for approval. The project cost dictates the level of GPC Management necessary for approval. The project and its alternatives are formally presented to the GPC Transmission Project Review Team (TPRT) for appropriate ranking. The project is then presented to various groups, all of which have previously participated in the problem formulation. Concurrence in the recommendation is also obtained from:

1. GPC Project Management, Engineering, Land, and Power Delivery (including Transmission, Distribution, and System Operations)
2. Operating regions
3. The ITS Participants through the TPWG or the Sub-Transmission Working Group (STWG), the JSTP, and the Joint Committee.

7b. INCLUSION IN CAPITAL BUDGET

Projects included in GPC's Capital Budget are reviewed and approved by the GPC T&D Council and subsequently approved by GPC executive management and the Board of Directors. When projects are approved, a commitment for funds is made. Therefore, before projects are approved in the Budget, final reviews must be made as to necessity, timing, and costs.

Revisions are necessary for Project Exceptions (PEs) in the Budget due to changes in plans, scopes, nature of the jobs, cost estimates, scheduled expenditures by years, or by substantial variations in actual cost from the estimated cost. A revision is also required when a project is canceled. Any necessary revisions to the Budget are made as soon as sufficient information is available.

Whenever PEs are revised, explanations of these revisions are included in the details on the PE forms. Revisions are justified as to necessity, timing and cost. If a change in estimated costs occurs in a PE revision, adequate explanations supporting the revised costs are given.

Budget revisions are made by approval of Budget Change Authorizations (BCAs). These proposed revisions follow the usual interdepartmental routing for approvals and then go to the GPC TPRT for final approval.

7c. BUDGETARY REVIEW AND CONTROL

The Budget is finalized by the fall of each year. The status of each transmission project scheduled for completion in the current year is reviewed by August to identify those projects that will not be completed by the end of the year. In order that funds will be available for the completion of these projects, the Budget is revised so that the necessary expenses can be carried over to the following year.

In addition to the above periodic review of the Budget, drastic changes in the load forecast or in the GPC financial situation necessitates an immediate review of the Budget.

Significant changes in the load forecast or generation expansion plan requires that each transmission project be reevaluated with respect to timing and scope. Sudden economic constraints placed on GPC expenditures require that each transmission project be reevaluated under revised capital availability.

Once the future needs of GPC have been identified and a Budget has been prepared, TP-E has a contributing role in budgetary control. Any significant project scope changes or costs substantially exceeding the budgeted amounts require that TP-E work with Project Management and other departments to affect changes in the projects or initiate Budget revisions so that the Budget continues to reflect GPC financial requirements.

8. TRANSMISSION PLANNING TOOLS

PSS/E Power System Simulator Program

The PSS/E Power System Simulator Program developed by Power Technologies Inc. (now Siemens Power Transmission & Distribution, Inc., Power Technologies International) is a state of the art power systems analysis tool that consists of several component programs to assist transmission planners in analyzing and planning the transmission system. The main programs used in the planning of the GPC Transmission system are the load flow and dynamic simulation programs. Fault analysis and Transmission line constant calculation programs are available but are not used within the simulator package. The following two main programs are used:

PSS/E Load Flow Program

The PSS/E Load Flow program models all essential parts of the power system network necessary to simulate the generation and transmission of power throughout the utility system. The program allows the transmission planners to use both AC and DC solution techniques to efficiently and effectively analyze the transmission system response for various contingencies and to develop transmission expansion.

PSS/E Dynamics Program

The PSS/E dynamics program is used for performing stability studies, e.g., time-domain simulations of power systems. It is used to model machines and associated controls (e.g., exciters, governors, and stabilizers) to perform traditional transient stability studies.

SSAT - Small Signal Analysis Tool Stability Program

The SSAT is a Powertech Labs program which is used for a wide range of power system problems such as the design of compensation networks for power system stabilizers; modulating controls for DC links; and the investigation of the stability of inter-area modes

associated with very large power systems. This tool is useful for determining the modes of oscillation of a power system and the damping of these nodes.

EMTP - Electromagnetic Transients Program

The EMTP is a time-domain simulation program that is used primarily to study transient events such as switching surges and lightning surges. However, because the power system is modeled on a per phase basis in the program, EMTP can also be used to study steady-state, unbalanced operation of power systems. EMTP has machine modeling capability which allows the study of the interaction of machines with power systems on a small scale. This capability is useful for studying phenomena such as sub-synchronous resonance.

Economic Dispatch Program

The Economic Dispatch Program was developed by SCS to interact with the Power Technologies Inc. load flow program, PSS/E. The program calculates an economic dispatch for a given load and spinning reserve requirement specified by the transmission planners and is based on the theory that the most economical dispatch is obtained by operating all on-line units at the same incremental cost (λ). The transmission planners specify information to the program through terminal interaction and two data files with pertinent information on the availability of units, in-service date, retirement date, must run status, power generation limits, generator cost data, etc. The program allows the transmission planners to input the appropriate economic dispatch directly into files for future use with the PSS/E program.

REVREQ - Revenue Requirements Program

REVREQ is a program developed by SCS to generate capital recovery requirements associated with individual or multiple capitalized investments made within the SCES. REVREQ incorporates the effects of income tax credits, accelerated depreciation methods, income taxes, deferred taxes, ad valorem taxes, and capital costs into the calculations of revenue requirement schedules associated with the capital investment to

be analyzed. The program uses specific Company related information or an average for the SCES in the determination of revenue requirements.

OHLOAD – Overhead Line Loading Program

OHLOAD is a dynamic ampacity rating program for electric conductors developed by the Electric Power Research Institute (EPRI) in conjunction with GPC and the Georgia Institute of Technology. The program calculates ampacity ratings, based on conductor temperature limits, by employing planner's input weather and location parameters. The weather parameters that have the greatest influence on the conductor rating are wind speed and ambient temperature. By utilizing OHLOAD, the transmission planners assist the operators in the evaluation of current system conditions and thereby minimize the amount of risk associated with short-term, excess conductor loading. This process may, in some cases, even delay or defer system improvement costs.

PSS/OPF - Power System Simulator Optimal Power Flow Program

The Siemens/PTI Optimal Power Flow program is used to optimize the power flow solution of large-scale electric power systems by minimizing a selected objective function while observing selected operating constraints. It is used primarily in studies to minimize transmission active power losses, transmission reactive power losses by optimizing the generator voltage schedule and/or the addition of capacitors on the power system.

VSAT - Voltage Security Assessment Tool

VSAT is a Powertech Labs power-flow based steady-state voltage stability assessment tool that allows the computation of voltage stability margins for power flows by increasing key power system parameters (load, transfers, etc.) from base case values to the point of voltage instability. VSAT, through Eigen value analysis, also provides information which pinpoints the areas which are most prone to voltage instability.

MUST - Managing and Utilizing System Transmission

The MUST program, developed by Power Technologies Inc., calculates electric transmission transfer capabilities and the impact of transactions and generation dispatch. Its results are key to more fully utilizing the electricity grid and managing the effect of power transactions and dispatch changes. The capability to move power from one part of the transmission grid to another is a key commercial and technical concern in the current electric utility environment. Planners determine transmission transfer capability by simulating network conditions with equipment outages during changing network conditions.

The purpose of the MUST software is to efficiently calculate:

- Transaction impacts on transmission areas, interfaces, monitored elements or flow-gates.
- Generation re-dispatch factors for relieving overloads.
- Incremental transmission capability (FCITC).
- FCITC variations with respect to network changes, transactions, and generation dispatch.

MUST complements PSS/E data handling and analysis functions with the most advanced linear power flow and user interface available. MUST's speed, ease-of-use, and versatile EXCEL interface simplifies and reduces data setup time, and improves results display and understanding.

PSS SINICAL - Power System Simulator Siemens Network Calculation Tool

The PSS SINICAL program was developed by Siemens and is used to perform harmonics and unbalanced (three-phase) power flow studies. The program is used by transmission planners to evaluate the harmonic impact of adding shunt capacitors to the system to provide voltage support. Additionally, the program is used to conduct three-phase power flow studies to assess the potential impacts of current and voltage imbalance on the system. SINICAL's ability to process PSS/E data provides for greater efficiency with regards to performing harmonics and unbalanced power flow studies as compared with using the EMTP program.

PPPD - Power Plant Parameter Derivation Program

PPPD is an EPRI developed program. PPPD can be used to validate and fine tune/estimate models and their parameters for synchronous generating units and their control using the data obtained through either staged field testing of the generating units or on-line disturbance data.

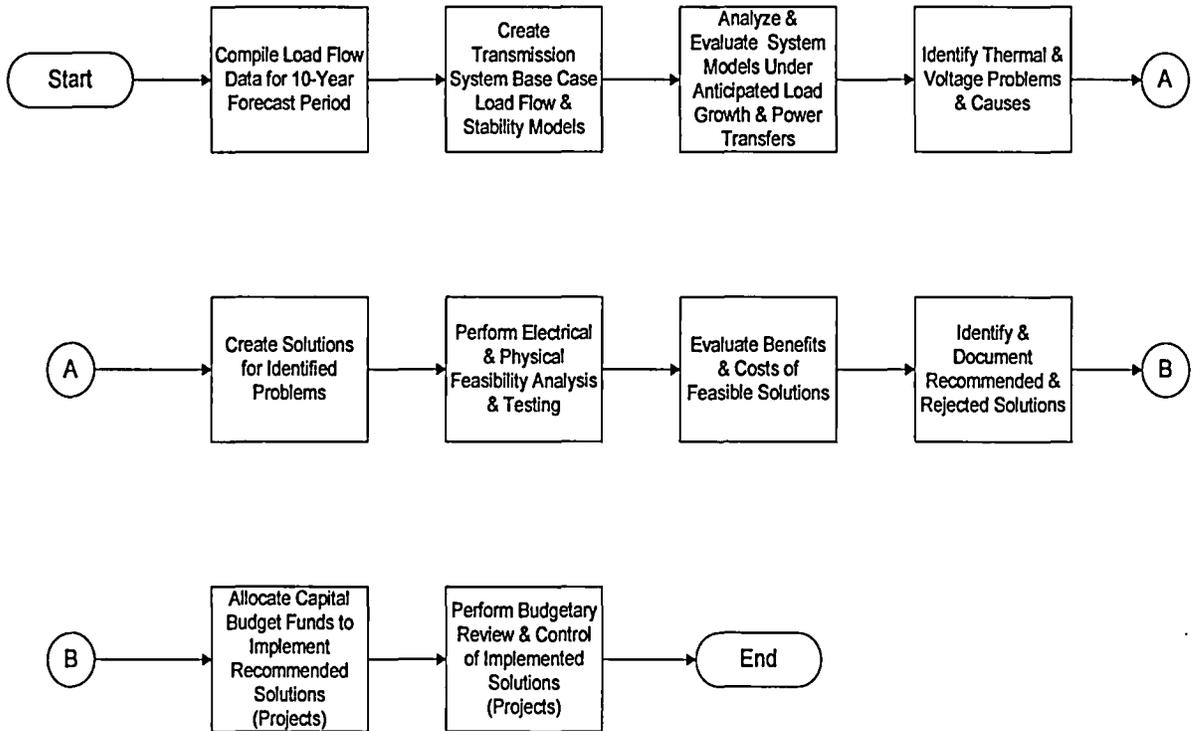
9. GUIDELINES

The following guidelines are to assist the transmission planners in fulfilling the task of transmission planning.

- The Capital Budget will accurately reflect the financial requirements of transmission additions on a per year basis.
- Transmission related expenditures will be minimized with appropriate consideration being given to system reliability.
- The ITS will meet or exceed all appropriate government and regulatory guidelines such as the: NERC Planning Standards, the Guidelines for Planning The Georgia Integrated Transmission System, and the Guidelines for Planning the Southern Company Electric Transmission System.
- The ITS will reliably and economically connect the generation system with load serving and other substations.
- Transmission ties with other systems will meet the requirements of the ITS.

10. Process Flow Diagram

Georgia Power Company Transmission Planning Process



[B]

**TRANSMISSION PLANNING
GUIDELINES**

[B1]

**NERC & SERC RELIABILITY
STANDARDS**

FOREWORD

The Georgia Power Company transmission grid is part of the Southern Company transmission grid, one of the largest interconnected systems in the country. The Southern Company service area includes portions of the states of Georgia, Alabama, Mississippi and Florida. In addition, Southern Company is a member of SERC, one of the regional reliability councils of NERC.

The Energy Policy Act of 2005 authorized the creation of a self-regulating electric reliability organization (ERO) that spans North America, with Federal Energy Regulatory Commission (FERC) oversight in the United States. The legislation makes compliance with NERC Reliability Standards mandatory and enforceable.

NERC Reliability Standards define the reliability requirements for planning and operating the North American bulk electric system. NERC may delegate authority to Regional Entities to monitor and enforce NERC Reliability Standards. As one of the Regional Entities, SERC is delegated to perform certain functions from the ERO and is subject to oversight from the FERC. SERC promotes and monitors compliance with mandatory Reliability Standards, assesses seasonal and long-term reliability, and monitors the Bulk Power System (BPS) through system awareness.

The Guidelines used for planning the ITS and Southern Company electric system are consistent with the NERC Reliability Standards. Additional information about NERC and the NERC Reliability Standards can be found at: <http://www.nerc.com>. Additional information about SERC can be found at: <http://www.serc1.org>.

[B2]

GEORGIA ITS

**TRANSMISSION PLANNING
GUIDELINES**

I.T.S. PLANNING PROCEDURE NO. 9
GUIDELINES FOR PLANNING
TRANSMISSION SYSTEM FACILITY IMPROVEMENTS
FOR THE
GEORGIA INTEGRATED TRANSMISSION SYSTEM

Issued: 6/28/1998
Revised: 6/17/2015

ASSOCIATED NERC STANDARD(S):

TPL-001-4 (referred to as TPL-001 in this document)

IMPLEMENTATION:

Phase in of individual TPL-001 requirements will be based on the effective dates as defined in TPL-001.

January 1, 2015 - R1&R7

January 1, 2016 - R2-R6, & R8

January 1, 2021 - Phase in of raising the bar requirements

- P1-2, P1-3, P2-1, P3-1 through P3-5,
- and for systems above 300kV P2-2, P2-3, P4-1 through P4-5, P5

PURPOSE:

The purpose of this document is to provide an overview of general transmission planning philosophies and objectives for planning the Bulk Electric System (BES) portion of the Georgia Integrated Transmission System ("ITS") , and to illustrate how the ITS Participants (Georgia Power Company ("GPC"), Georgia Transmission Corporation ("GTC"), the Municipal Electric Authority of Georgia ("MEAG"), and Dalton Utilities ("DU")) address each requirement of the NERC Reliability Standard TPL-001. This guideline documents the study requirements and the associated BES performance criteria that form the basis for the Planning Assessment, which covers the Near-Term (years 1-5) and Long-Term (years 6-10) Transmission Planning Horizons. The Planning Assessment covers a broad range of system conditions and Contingency events as defined in TPL-001 Table 1.

This guideline addresses the steady state and stability topics of TPL-001. Since stability topics are now included with this revision, ITS Planning Procedure No. 20 ("Generator Stability Guidelines") is retired. The short circuit topics of TPL-001 are addressed in a separate document "Guidelines for System Modeling and Short Circuit Assessment of the Georgia Integrated Transmission System" (Attachment A).

The "Transmission Planning Philosophy and Objectives" section below is intended to assist in understanding high-level planning objectives and to provide context regarding transmission planning within the ITS. Sections 1 through 8, which correspond to the requirements R1 through R8 in the NERC Reliability Standard TPL-001, provide general technical guidelines

for Transmission Planners in meeting the reliability requirements of TPL-001. Each section is organized starting with the NERC TPL-001 requirements being provided in a Gray box, followed by guidance on approaches to meeting the requirement.

The intent of these guidelines is to help the planner or other interested reader more fully understand the philosophies behind the planning processes, and the approaches applied in meeting the planning requirements. The background transmission planning information provided herein is not intended to conflict with or circumvent any requirements in NERC TPL-001, nor should any passages be inferred to remove or increase compliance obligations under the NERC Reliability Standards, or any other applicable state or federal laws or regulations. In any cases where a reader might infer a potential conflict, the governing provision is the NERC TPL-001 requirement.

Transmission Planning Philosophy and Objectives

Before discussing how the reliability requirements of NERC TPL-001 are addressed, which will be covered in detail in Sections 1 through 8, it may be helpful to better understand several areas of focus for planning transmission in the ITS, and the reasoning behind them. A primary responsibility of transmission planning for the ITS Participants is to comprehensively assess how to provide for reliable and economic future system operations, including understanding how physical, economic, and regulatory factors may affect how power system facilities operate. The following discussion is intended to help increase understanding of why transmission planning for the ITS has a proactive, long-term focus on physical delivery capability, and how doing so helps reduce uncertainties, supports transmission customers in their decisions, and enables more cost effective solutions and system operations.

Fully Meet Reliability Requirements

The goal of the ITS Participants in the transmission planning process is to provide transmission customers Safe, Reliable, and Affordable delivery from their resource choices to their customer loads through dependable long-term firm physical transmission service. Long-term firm transmission service in the ITS is considered physical in that cost effective options are identified to create sufficient physical transmission capacity to enable reliable physical delivery of the transmission customer's service under a wide-range of system conditions. Securing long-term firm physical transmission service provides customers delivery priority throughout the year with the intent that their service will rarely be interrupted or curtailed. Toward this end, it is The ITS Participants' intent to fully meet or exceed NERC and SERC reliability requirements and related reliability criteria applicable to transmission planning.

Support Flexible, Reliable, and Resilient Operations

One of the goals of transmission planning is to minimize challenges in the operating environment to the extent practical by identifying potential operating constraints and mitigations in advance, and planning a transmission system which reliably supports transmission customers' needs. Transmission planning coordinates closely with system operators to review actual stressed system conditions as well as anticipated future conditions to reflect them in transmission models. The transmission planning process considers both the reliability requirements of the NERC planning standards and also the broader scope of operational implications such as impacts on operating reserves, regulation/ramping needs, power quality, resiliency, restoration capabilities, and other operational needs. Examples include:

- Ability to economically dispatch network resources and other firm physical transmission service under alternate system conditions
- Ability to perform maintenance and restoration activities
- Ability to reliably mitigate stressed system and potentially recurring operating conditions identified by system operators
- Operational impacts of variable energy resources
- Operating implications of changes to firm network generation facilities, coordinating with resource planners and generator operators to understand, model, and assess:
 - Firmness of fuel supplies and capabilities of backup fuel storage
 - How environmental constraints may impact plant performance (Impacts of a major Gas Pipeline disruption or prolonged rail service interruption)
 - Nuclear offsite power and coordination requirements
 - Outage stability limits related to maintenance activities
 - Impacts on system resiliency and restoration/blackstart capabilities
- Impacts to operating reserve requirements
 - Generation additions/changes are assessed and configured such that a single contingency will not disconnect more generation than the loss of the largest single unit within the Southern Balancing Authority Area (SBAA) (currently ~1300 MWs). Similarly, proposed HVAC or HVDC interfaces are also assessed for potential impacts to reserve levels.
- Impacts to the ITS and neighboring transmission systems, as well as The ITS's ability to serve customer demand, as a result of extreme events. Extreme events include outages of several bulk electric facilities such as the loss of multiple transmission lines utilizing common towers or rights-of-way, loss of all generating units at a plant, or the loss of a substation.

In support of future system operations, the ITS seeks to ensure that transmission system performance remains reliable, robust, and resilient to address both normal and severe operating conditions and events. To address the uncertainties inherent in transmission planning inputs (such as load forecasts, resource changes, variable generation, and fuel forecasts), the ITS assesses long-term firm physical delivery service needs and identifies affordable transmission expansion options considering a wide range of scenarios and operating conditions, providing not only a degree of margin in ensuring compliance with all applicable reliability standards, but also providing necessary operational flexibility in economically accessing firm network generation resources, scheduling maintenance/construction activities, and responding to significant system events.

Long-term Focus on reducing resource uncertainties, costs, and delivery risks

Transmission planning at the ITS has a long-term focus aimed at mitigating delivery risks and delivery cost uncertainties for long-term firm transmission customers. Long-term firm physical transmission service enables transmission customers to dependably meet their current and future customer obligations through securing delivery service priority provided in an affordable manner at predictable costs. Transmission service requests and commitments made by transmission customers for long-term firm physical transmission service result in removing resource uncertainties from the planning process, and enable transmission planners in assessing their transmission customers' specific delivery needs, thereby providing lead-time to identify and implement reliable and cost effective delivery options

PUBLIC DISCLOSURE

The Load Serving Entities (LSEs) of the ITS, as well as those of most non-affiliated transmission customers, have “Duty to Serve” obligations that require them to ensure adequate and reliable energy supplies at affordable rates for both their current and future customer loads. LSEs in the Southern Balancing Authority Area (SBAA) strive to meet their “Duty to Serve” obligations through procuring generating capacity on a least total cost basis, which includes the consideration of transmission delivery costs and the lead-times required to implement any associated transmission expansion.

The ITS transmission planning process enables and encourages LSEs to designate sufficient network resources to serve their forecasted network loads on a long-term firm basis throughout a ten year planning horizon and beyond. LSEs and other transmission customers have the opportunity to develop generating resources (or alternately, to procure Purchase Power Agreements) by having access to the transmission delivery cost implications of their decisions, and the ability to secure priority firm physical transmission service to ensure reliable and affordable delivery during the life of their assets or agreements. At times when resource decisions may not yet be known or finalized (typically later in the planning horizon), LSEs may provide native load reservations for future resources as inputs into the transmission planning process. However, to receive firm service, LSEs must make transmission delivery commitments (designations) early enough to enable all required transmission expansion to be completed prior to or coincident with the commencement of the desired delivery service from the designated resources. In this way, most transmission delivery commitments within the 1-5 year planning horizon are known, supporting sufficient lead-times for economically constructing transmission enhancements. Transmission enhancements for point to point transmission customers are also assessed, in a comparable manner, and completed in advance of their delivery needs. Transmission planning is open and transparent with transmission reservations and studies being available through the Open Access Same-time Information System (OASIS).

Reliable Firm Physical Transmission Service

The ITS seeks to ensure that long-term firm physical transmission service is reliable (and seldom subjected to curtailments), enabling transmission customers to mitigate both delivery risks and delivery cost exposure in their resource decisions. The transmission planning approach to providing firm physical transmission service is to meet reliability requirements and also maintain the ability of long-term firm transmission customers to operate their resources economically across a range of credible system conditions. For example, the reliability impacts of system contingencies (such as the loss of any line or transformer coupled with the loss of any generator) are addressed in a manner which does not rely upon curtailing generation with firm transmission service or shedding firm loads. In generation pockets, an “Area Max” sensitivity is performed for all generation with firm transmission service to ensure that generation capacity is not “trapped” in a given area. Through ensuring adequate physical capacity is in place to meet long-term firm delivery needs, transmission customers receive highly dependable physical delivery service with rare curtailments.

Economic Timing of Transmission Expansion Projects in Corrective Action Plans

Transmission planning for the ITS is a highly iterative and continuous process to accommodate potentially changing inputs. Transmission expansion plans are not a blueprint, but rather provide a snapshot of the currently identified project solutions and timing. Transmission expansion plans are continuously reassessed and revised to reflect updated load forecasts, resource changes, new firm delivery service or reliability requirements, new public policy requirements, new solution options, and other drivers. The ITS strives to identify

the most cost effective options for meeting reliability and delivery service requirements, and also strives to implement them to coincide with the timing of the transmission delivery service need.

In continually seeking to reduce costs to transmission customers, transmission expansion projects which are not in a construction stage are reassessed each year. Expansion projects may be deferred or removed if the reliability need is delayed or goes away. Expansion projects may be replaced if more economic solutions are identified. Expansion projects may need to be advanced if the reliability need is advanced. By timing completion to coincide with delivery service needs, transmission customers are able to commence their delivery service when requested, benefit from more cost effective solutions that may arise during the interim, and avoid premature carrying costs.

Table of Contents

This guideline is organized in a format similar to the NERC TPL-001 standard. The text in shaded grey boxes is taken from the NERC standard. Sections 1 through 8 of this document apply to steady state and stability issues. Sections 9 through 12 (in Attachment A) apply to short circuit issues. The standard requirement topics are generally organized as follows:

1.0	R1 – Model Requirements	6
2.0	R2 – Annual Planning Assessment and Corrective Action Plan	7
3.0	R3 – Steady State Studies.....	15
4.0	R4 – Stability Studies.....	22
5.0	R5 – Voltage Evaluation Criteria.....	27
6.0	R6 – System Instability Evaluation Criteria.....	30
7.0	R7 – Planning Coordination / Transmission Planning Roles and Responsibilities	31
8.0	R8 – Planning Assessment Distribution	32
9.0	R1 – System Model Requirement	34
10.0	R2 – Annual Short Circuit Assessment and Corrective Action Plan	35
11.0	R7 – SCST Protection & Control Applications roles and responsibilities	36
12.0	R8 – Short Circuit Assessment Distribution.....	37

Guideline

1.0 R1 – Model Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.

Southern Company Services Transmission's (SCST) Transmission Planning department maintains Transmission system modeling data for the Southern Balancing Authority Area (SBAA), including the ITS Participants' facilities, in a database which is used to typically build up to a 10 year planning horizon series of base case system models. The resulting models are used by ITS Participants to complete the Transmission Planning steady state analysis studies and are the basis for stability study model development. The model data is consistent with the requirements of NERC standard MOD-032-1¹. The planning base case models contain the most recent as-built system data plus the most recent projected Corrective Action Plan (CAP) projects and therefore represent the projected system conditions. Transmission Planning base case models are developed utilizing input from applicable Eastern Interconnection Reliability Assessment Group (ERAG) and SERC regional modeling processes, such as the Long-Term Study Group (LTSG).

Transmission base case models are developed or modified at least on an annual basis to reflect the most current information and assumptions available concerning the modeling of future year's system.

The system dynamic models for the Southern sub-region of SERC are based on the same steady state system model with the addition of machine dynamic model data provided in accordance with MOD-032-1. Machine dynamic data have been collected from all existing generators on the system. As-built machine dynamic data are required from every interconnecting generator prior to commercial operation. Machine dynamic data for forecasted machines in the Long-Term Transmission Planning Horizon may not be available from the Generator Owner (GO). In those cases, dynamic data is assumed based on a similar machine type and is updated as provided by the GO.

1.1. System models shall represent:

- 1.1.1. Existing Facilities
- 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
- 1.1.3. New planned Facilities and changes to existing Facilities
- 1.1.4. Real and reactive Load forecasts
- 1.1.5. Known commitments for Firm Transmission Service and Interchange
- 1.1.6. Resources (supply or demand side) required for Load

¹ MOD-010 and MOD-012 have been consolidated into MOD-032-1.

The system modeling process includes representation of:

- 1.1.1 Existing generation and Transmission facilities based on the most recent as-built data provided by the Generation Owner (GO) or the Transmission Owner (TO).
- 1.1.2 Known generation or Transmission outages in the planning horizon occurring during modeled system conditions with an expected duration of six months or longer.
- 1.1.3 The Transmission system topology, including projects in the most recent CAP and other expected Transmission improvements for the Near-Term and Long-Term planning horizons. The current forecasts of generation expansion or resource plans are provided by all Load Serving Entities (LSE's) and Network Integration Transmission Service (NITS) customers.
- 1.1.4 Real load forecast is obtained from the LSE's latest forecast and from all NITS customers for peak and relevant Off-Peak conditions. Reactive load forecast is based on field measured data of the existing system which is extrapolated with a constant power factor for future planning horizon years. Specific future loads such as new or expanding large industrial customer loads (real and reactive) are modeled based upon the best available data.
- 1.1.5 Known Firm Transmission Service Commitments.

The interchange between external systems is based on the most current external system models provided from interconnection-wide and regional data bank models such as the ERAG's Multiregional Modeling Working Group (MMWG) or SERC's LTSG. Additional modeling updates obtained from neighboring utilities and/or other modeling coordination processes may also be used.

- 1.1.6 Generation resource assumptions are based on the latest information provided by the LSEs and NITS customers. In addition, generators with approved Firm Transmission Service Agreements (TSA's) are typically modeled on-line at the TSA output level consistent with 1.1.5.

2.0 R2 – Annual Planning Assessment and Corrective Action Plan

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

Each ITS Participant prepares an annual 10-year Transmission Planning Assessment. A corresponding CAP is developed jointly by all Participants.

Steady state: The steady state portion of the Planning Assessments are prepared annually, reference the applicable studies which have been performed, and contain the Near-Term and Long-Term horizon CAP for meeting the TPL-001 requirements. The steady state assessments cover evaluation of thermal loading of facilities and bus voltages after

incorporation of the CAP required to meet TPL-001 Table 1 performance criteria. The assessments document the study assumptions and summarizes study results validating the CAP. For Southern Company, the consolidated steady state analysis Planning Assessment consolidates the CAPs of GPC and Southern's other three OPCos. Each ITS Participant's CAP includes the other Participants' transmission system plans.

Stability: The stability portion of the Planning Assessment is prepared annually and references the applicable studies which have been performed. This portion of the assessment documents the assumptions and summarizes the results of the stability analyses. The studies are used to develop recommendations involving relay schemes, breaker specifications or requirements, System Operating Limits (SOL's), and System improvements. The recommendations made are included in the stability portion of the CAP.

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6.

Steady state: The Planning Assessments are based on annual studies which are performed for each year of the Near-Term Planning Horizon. These studies consider TPL-001 Table 1 Category P0-P7 Planning Events and Extreme Events. The results demonstrate that required performance criteria are met based on a jointly developed CAP. This CAP is reassessed each year to confirm continued need, timing, and scope for previously identified projects until projects have transitioned from planning to a construction stage. These reassessments also investigate potential need for additional projects or modification to projects currently included in the CAP. The CAP considers and reflects the respective lead times to complete any identified Transmission projects.

Qualifying studies need to include the following conditions:
2.1.1. System peak Load for either Year One or year two, and for year five.
2.1.2. System Off-Peak Load for one of the five years.

2.1.1 – System peak loading models representing summer loading conditions are developed and studied for each of the five years in the Near-Term Transmission Planning Horizon. These models are produced by Southern Company Transmission Planning for the entire SBAA, including the ITS Participants.

2.1.2 – System Off-Peak load models, which represent approximately 93% of Summer Peak Demand with hydro generation motoring (for hydro units capable of motoring²), are developed and studied for each of the years in the Near-Term Transmission Planning Horizon. This Off-Peak load assumption for steady state analysis is anticipated to result in the highest Off-Peak System stress with a significant portion of energy limited resources (hydro and solar) projected to be off-line. These cases are also referred to as "Shoulder case" models.

² Motoring, also known as synchronous condenser operation, models the generator controlling voltage using the reactive capabilities of the machine. Motoring requires a small amount of real power from the transmission system to supply station service, and to overcome windage and friction of the generator.

An additional series of Off-Peak cases are evaluated which represent approximately 70% of the Summer Peak Demand.

Qualifying studies need to include the following conditions:

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

Known generation or Transmission outages with a projected duration of 6 months or more in the Near-Term Transmission planning horizon will be modeled with the impacted equipment out-of-service as described in R1. If outages meeting this criterion are identified during modeled System conditions, the outages are modeled and cases evaluated considering an additional P1 planning event.

Qualifying studies need to include the following conditions:

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

System base case models are considered starting points for Peak Demand and Off-Peak evaluations. The CAP is developed based on these System models and analyzed against a range of assumption sensitivities such as those listed in R2.1.4 for Peak Demand and Off-Peak conditions. The Planning Assessments will document the sensitivity study assumptions evaluated in the planning studies.

Generating resources are modeled in the base cases to meet forecasted loads. In Near-Term Transmission Planning Horizon models, available generation is typically known. In Long-Term Transmission Planning Horizon models, LSEs may include forecasted generation to meet their forecasted load growth. Sensitivity cases should be evaluated to determine if forecasted generation should be relocated in the model for local area planning to avoid an unintended positive or negative impact on analysis results.

Qualifying studies need to include the following conditions:

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

The Transmission equipment sparing strategy will be reviewed annually to identify Transmission equipment with a manufacturing or replacement lead time greater than one year. During system studies, if any long lead time Transmission equipment (one year or more) is identified that does not have a spare, then its unavailability will be modeled and evaluated with P0, P1, P2 events considered in the Near-Term Transmission Planning Horizon.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Steady state: Annual planning studies are performed for TPL-001 Table 1 P0, P1, and P3 category planning events for each year in the Long-Term Transmission Planning Horizon. P2, P4-P7, and Extreme Events are evaluated for at least one year of the five year Long-Term Transmission Planning Horizon. The rationale for selecting the year to study is discussed as a part of the report documentation.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Short Circuit: Addressed in "Guidelines for System Modeling and Short Circuit Assessment of the Georgia Integrated Transmission System".

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

The stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon is prepared annually and utilizes the applicable current or past studies which have been performed.

Stability studies are generally performed for two system load levels –Summer Peak Demand and 50% of Summer Peak Demand (Off-Peak load).

2.4.1 The annual Peak Demand case studied is generally chosen to be a later year in the Near-Term Transmission Planning Horizon because System load tends to increase with time in the planning models. The annual Peak Demand cases include a dynamic load model which represents the effects of induction motors.

2.4.2 The Off-Peak case with load levels 50% of the Summer Peak Demand is modeled for an early year in the Near-Term Transmission Planning Horizon.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

Stability base case models are considered as starting points for system evaluations. The CAP is developed based on these system models and analyzed against one or more of the assumption sensitivities listed above.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.

Stability: A stability assessment is made for the Long-Term Transmission Planning Horizon for known generation additions or changes. This assessment may utilize applicable current or past studies which have been performed.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

Steady state: Steady state analysis for the Near-Term and Long-Term Transmission Planning Horizon is typically performed annually and therefore use of past studies under R2.6 would not normally apply. However, in situations where qualifying past studies are still deemed appropriate under 2.6, then the required supporting technical rationale will be provided with the Planning Assessment.

Stability: Qualifying past studies will be used along with current studies for the stability assessment. When past studies are used, documentation will be included with the Planning Assessment showing that no material changes have occurred in the system which would affect the results of the study. Also, when past studies are more than five calendar years old, a technical rationale will be provided to show why the study is still valid.

Short Circuit: Addressed in "Guidelines for System Modeling and Short Circuit Assessment of the Georgia Integrated Transmission System".

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3.

Steady state: The Planning Assessment is based on annual studies of TPL-001 Table 1 performance requirements. The CAP is summarized in an attachment to the annual Planning Assessment report.

Stability: The stability portion of the Planning Assessment is based on current and past studies which have been performed. These studies are used to develop recommendations involving relay schemes, breakers, operating limits, and system improvements. The recommendations made are included in the stability CAP spreadsheet. The spreadsheet is

attached to the annual Stability Planning Assessment report contains deficiencies found and actions needed to meet the required system performance.

The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

The annual planning process includes simulation of each of the planning events of TPL-001 Table 1. In cases where the existing Transmission system does not meet the TPL-001 Table 1 performance requirements, a CAP will be developed that includes combinations of operating guides and Transmission expansion projects. In cases where operating guides are used to meet system performance requirements, those guides are reviewed at least annually with system operations as part of the planning process.

Each year the CAP from the previous year is reevaluated based on any known or forecasted system changes (including modification or retirement of Transmission or generation Facilities) and updated as needed. The annual Transmission planning study is the evaluation of the most recent CAP's ability to meet the performance requirements of TPL-001 Table 1.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

Transmission enhancements recommended as part of the CAP are based on the 10 year planning horizon base cases that represent the latest load and generation forecasts provided by the LSEs and NITS customers. The effectiveness of the CAP will be evaluated against future sensitivity scenarios as described in R2.1.4 and R2.4.3. If the CAP is found to not address performance requirements for multiple future sensitivities, then the proposed CAP solutions would be re-evaluated considering factors such as operational flexibility or system restoration flexibility. An explanation will be provided in the Planning Assessment if the CAP is not modified to address performance deficiencies observed in multiple sensitivity studies.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

In some cases, unexpected system changes may occur beyond the control of the Transmission Planner or Planning Coordinator which prevent the planned implementation of a CAP or result in the CAP not achieving the intended results. In such cases, if a revised CAP cannot be implemented in the required timeframe, the Transmission Planner will document the actions being taken to correct the situation. During the transition, the Transmission Planner will identify and document the situation which caused the problem, the options evaluated to address it, and whether non-consequential load loss or curtailment of Firm Transmission Service are being utilized during the interim until a permanent solution is in place. In addition to the near-term actions being taken to mitigate the reliability constraint, the CAP will also be updated to document the expected in-service date of facility additions needed to resolve the situation without relying upon non-consequential load loss or curtailments.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

The CAP is reviewed and updated annually and as needed. Operating guides are discussed each year with Transmission Operations to ensure validity as needed. The CAP will contain the implementation status.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

Short Circuit: Addressed in “Guidelines for System Modeling and Short Circuit Assessment of the Georgia Integrated Transmission System”.

3.0 R3 – Steady State Studies

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.

Steady state: The Transmission Planner and Planning Coordinator perform studies for the Near-Term and Long-Term Transmission Planning Horizons per Requirement R2, Parts 2.1, and 2.2, respectively. These studies are based on computer simulation models that are updated annually using data provided per Requirement R1.

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

Steady state: System studies are performed for each category of planning events of TPL-001 Table 1 as described in R3.4 with contingencies evaluated per R3.3.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

Steady state: The extreme events described in R3.5 are modeled based on Subject Matter Expert (SME) knowledge of the System.

These post extreme event simulations are reviewed to determine if they result in:

- Loss of substantial customer demand (generally exceeding loss of 300MW of total load), or
- Cascading outage of Transmission Facilities (per the criteria in R6), or
- The inability of a portion of the balancing area to reach a stable post-event operating point, or
- Potential impacts beyond the Reliability Coordinator area into neighboring Systems.

Extreme events with significant potential impacts will be reviewed and options to mitigate the impacts identified. CAP recommendations will consider the probability of occurrence, severity of potential impacts, and the associated costs.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.1 – SMEs evaluate contingencies on the transmission system to simulate a post-fault clearing steady state case consistent with protective device operation.

3.3.1.1 - Generators in the SBAA are generally modeled explicitly including their step up transformers. The model includes generator reactive limits and generator terminal voltage limits which have been provided by GOs. Terminal voltage limits, including voltage limits due to station service, are based on a coordinated study with generating plant owners/operators. Generators in the model are generally set to regulate the high side bus voltage to a scheduled value without violating the generator reactive limits. If the generator reactive capability is not sufficient to maintain the high side bus voltage, the generator is fixed at its reactive power absorption or production limit in the simulation solution. Planners monitor the generator terminal voltage in their studies to ensure the voltages are within the acceptable range provided by the GO. If the generator terminal voltage is below the acceptable value either the generator terminal voltage limit must be addressed by the CAP or the generator must be assumed to trip as a result of the initiating Contingency.

3.3.1.2 – The evaluation of Transmission Facility tripping based on relay loadability will be initially performed with a conservative screening process. If the screening process indicates potential relay operation then a detailed review will be conducted based on actual relay settings.

Transmission lines

230kV and above transmission line contingency case line loading results are screened against 150% of the maximum continuous facility rating and where exceeded are evaluated against actual relay setting.

Below 230kV transmission line contingency case line loading results are screened against 125% of the maximum continuous facility rating and where exceeded are evaluated against actual relay setting.

Autotransformers

500/230kV or 230/115kV autotransformer contingency case transformer branch loading results are screened against 125% of the maximum continuous facility nameplate rating, and where exceeded, are evaluated against actual relay setting.

If the screening results exceed the conservative limits:

- Request the actual Zone 3 or transformer overload relay trip settings for the Facility in question.
- If the contingency loading exceeds the actual Zone 3 or transformer overload settings, determine the proper corrective action.

For events where subsequent Facility tripping (cascading) is not allowable P0 – P7, the corrective action items could include allowable modification to relay settings or schemes, or other solutions including System modifications.

For extreme events where subsequent Facility tripping is allowed, corrective actions similar to P0 - P7 events may be evaluated, or the opening of the line or transformer branch may be evaluated per R3.5.

In either case, when System adjustments or operating guides are used to reduce a Facility loading within an acceptable time, an assessment is performed to ensure that the contingency loading did not exceed overload relay settings to ensure that Facilities do not trip based on relay loadability.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

In steady state analyses, devices that have automatic operations are modeled in automatic mode, such as load tap changers, switched reactive devices, and continuous reactive devices. Also, generator operator generator terminal voltage adjustments to meet voltage schedules are simulated by modeling in automatic mode.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

The analysis methods used to model the planning events of Table 1 vary by event, therefore an explanation is provided for simulations of each planning event. For most P0-P7 category events, all events in the ITS meeting the event description are evaluated unless specifically noted in the study. Therefore “a more severe event contingency list” is not created. For situations where all events are not modeled in the study an explanation is provided in the following discussion for each event category. In all cases, the post-contingency simulation results, branch thermal loadings, and bus voltages are compared to acceptable facility ratings. The planning studies are designed to cover each category of planning event from NERC TPL-001 Table 1 as follows:

- P0 - Evaluation of normal System with no Contingency event is achieved with a thermal and voltage limit check of all ITS BES elements for each study case.
- P1 - Evaluation of normal System performance for single Contingency events will be performed to demonstrate the capability of the System without allowing Non-

Consequential load loss. In the unlikely event that Non-Consequential load loss is used to address BES performance the process described in TPL-001 Table 1 footnote 12 and Attachment 1- Stakeholder process would be followed.

- P1.1 – Evaluation of loss of generation event is performed using a series of base cases where key individual generator units³ are modeled off-line, and the remaining SBAA generation is re-dispatched to meet SBAA load for each of these generator off-line contingency (N-G) cases. A list of the key individual generators is provided in the study documentation. The required re-dispatch is based on expected SBAA dispatch order and is performed only to balance SBAA generation with SBAA load, losses and interchange while maintaining appropriate spinning reserves and keeping the analysis' swing machine within its limits.
- P1.2 – The simulation software has an automated tool which outages each Transmission circuit branch in the system model one branch at a time. Therefore a list of Contingencies is not required since all possible ITS Contingencies are evaluated.
- P1.3 – Two-winding transformers are a subset of P1.2 branches. Any three-winding transformers in the ITS receive a special review requiring SME Contingency evaluations.
- P1.4 – Shunt devices which are expected to have a significant impact on the BES are identified by SMEs and modeled with a low impedance branch connecting a dedicated shunt bus to the network model bus. This low impedance branch modeling method results in analysis of shunt devices as a subset of P1.2. A list of shunt devices modeled with low impedance connecting branches is provided in the study documentation.
- P1.5 – Not applicable. In the ITS, HVDC lines are not currently installed and no HVDC lines outside of the ITS have been identified as affecting the ITS.
- P2.1 – For steady state post-event analysis, this category of event is analyzed as a subset of the P1.2 analysis. In limited circumstances, if Non-Consequential Load Loss were used to address BES performance, the process described in TPL-001 Table 1 footnote 12 and Attachment 1- Stakeholder process will be followed.
- P2.2 – Bus section faults are modeled and analyzed based on specific substation bus configurations to provide for the expected operation of system protective devices, including bus differential schemes, due to a single event. The EHV and HV BES levels are evaluated separately consistent with Table 1 performance criteria. A list of bus section faults modeled is provided in the study documentation.
- Substations with multiple straight bus sections have each bus in the ITS modeled discreetly as separate bus nodes simulating Bus-tie breakers. Contingencies are performed to simulate each bus section's bus differential relay operation.
 - Substations with a ring bus configuration are typically modeled in base cases as a single node. Detailed substation models are built allowing contingencies to be performed simulating each bus section's line relay operation which opens the ring for evaluation.
 - Substations with a breaker and ½ configuration are modeled in most base cases as a single node. Contingency evaluations of bus section outages

³ For combined cycle units individual unit contingencies include the full CT + ST outage.

are not routinely studied since in initial design these substations are planned to allow a main bus out for maintenance. Individual bay section outages resulting in a line open at the substation are evaluated as part of the P2.1 review.

- P2.3 – Internal breaker faults (non-Bus-tie Breaker) are simulated by modeling back-up breaker operation on either side of the failed breaker. The EHV and HV BES levels are evaluated separately consistent with Table 1 performance criteria. A list of non-bus-tie internal breaker faults modeled is provided in the study documentation.
- P2.4 - Internal breaker faults on Bus-tie breakers are simulated by opening all breakers on the buses on either side of the Bus-tie. A list of bus-tie internal breaker faults modeled is provided in the study documentation.
- P3 – Individual N-G cases developed for P1.1 category (generator outage) events are the starting point cases for subsequent single Contingency P3 event studies. The re-dispatch required as a result of the assumed generator outage is not performed as a system adjustment for the purpose of addressing System issues resulting from the individual generating unit assumed to be off-line. The system adjustment philosophy is described at the end of this section. In limited circumstances, if Non-Consequential load loss were used to address BES performance, the process described in TPL-001 Table 1 footnote 12 and Attachment 1- Stakeholder process would be followed.
- P3.1 - The loss of a P3.1 second generator (N-2G) is generally simulated using the PSS/E contingency analysis feature as the loss a generator step up (GSU) transformer branch. This occurs automatically since the GSU is modeled explicitly. Combined Cycle (CC) units are generally connected to the System through a single branch and this branch outage in the contingency analysis simulates the total loss of the CC. In addition, SME-selected N-2G simulations are also performed to evaluate the P3.1 loss of generator event.
- P3.2 – P3.4 - Evaluated in the same manner as P1.2 - P1.4 except with the P3 “generator off-line contingency” cases.
- P3.5 - Not applicable as HVDC lines are not currently installed in the ITS and no HVDC lines outside of the ITS have been identified as affecting the ITS.
- P4 – Stuck breaker event analysis, in the post-fault clearing steady state results in the same evaluation as a P2.3 internal breaker failure event.
- P4.1- P4.5 – For steady state this event is the same as P2.3.
- P4.6 – For steady state this event is the same as P2.4.
- P5 – Failed non-redundant relay scheme operation (applies to primary schemes not breaker failure schemes) event analysis in the post-fault clearing steady state results in the same evaluation as a P2.3 breaker failure or P4 stuck breaker analysis as the breaker fails to operate in either case. Therefore, these events result in the same analysis as a P2.3 and P2.4.
- P6 - System adjustments, as described later in this section, made following the initial condition event in preparation for the P6 event are noted in study results.
- P6.1 – P6.3 – The PSS/E simulation software contingency enumeration feature is used to rank all possible ITS two branch-offline Contingency combinations. The program then solves cases for branch pairs in ranked order based on the defined success cut-off criteria. Shunt devices are modeled and outages simulated as described in P1.4.
- P6.4 - Not applicable as HVDC lines are not currently installed in the ITS and no HVDC lines outside of the ITS have been identified as affecting the ITS.

- P7.1- Outages of two Transmission circuits that share a common tower for greater than one mile are simulated with SME individual contingency files. A list of common tower loss events is provided in the study documentation.
- P7.2 - Not applicable as HVDC lines are not currently installed in the ITS and no HVDC lines outside of the ITS have been identified as affecting the ITS.

The following two sections detail the use of the terms “system adjustments” and “operating guide” in study methods and documentation.

System Adjustments for steady state studies

The concept of a system adjustment is referred to in performance category P3 and P6 requirements of the TPL-001 standard. Typically the standard is referring to an adjustment during an undefined time period between unrelated contingencies of a multi-Contingency event performance requirement. The assumption in the TPL-001 standard is that system operators would make system adjustments following the initial Contingency event to be prepared for a subsequent Contingency event.

For P3 category initial conditions, following loss of a generator unit, system adjustments may include Transmission switching and allowable generation dispatch adjustments in preparation for an additional P3 contingency event.

For P6 category initial conditions, following loss of a Transmission element, system adjustment may include Transmission switching and allowable generation dispatch adjustments in preparation for an additional P6 contingency event.

Extreme Event analysis under R3.2 will require analysis of the system performance assuming system adjustments were not made following the initial P3 or P6 event and prior to the P3 or P6 second contingency event. The following are not classified as system adjustments:

- For P3, the expected system re-dispatch of generation consistent with P1.1 in a study case performed to maintain the load/generation balance that is not made to favorably prepare the system for a subsequent event is not classified as an intentional system adjustment.
- Other adjustments which occur in a simulation to model automatic equipment operation such as voltage regulator operation, SVC control operation, or switching of shunt reactive devices (based on voltage set points) occurring as designed are not classified as an intentional system adjustment.

Operating Guides

An operating guide is an action performed as a post-contingency Corrective Action to alleviate a thermally overloaded facility or a facility with a voltage violation. Those guides meet the following criteria and must be performed within a time duration such that facility designed maximum operating temperatures are not exceeded.

- Generation dispatch performed to address specific post-contingency voltage or thermal performance requirements is limited to fast start generation (< 15 minutes) or the ramp rate of specific generation. Where dispatch is used as an operating guide, alternatives are evaluated to determine whether the operating guide relies on a single generator, or if similar acceptable post-contingency system results could be

achieved with other generation options. In general, operating guides relying upon a redispatch of a single generator option are avoided.

- Transmission configuration changes such as operator controlled switching actions, load transfers, etc. which are performed manually at an operator's direction to address specific post-contingency voltage or thermal performance requirements must be able to be performed within a time period such that the facility does not exceed its designed maximum operating temperature. The amount of time available for post-Contingency operator initiated remedial actions is determined based on the pre-Contingency and post-Contingency Facility loading levels. These two loading levels are inputs to a short-term current carrying capability assessment which estimates the amount of time required for a conductor to reach its rated operating temperature post-Contingency based on its pre-Contingency loading level. Typically, 15 minutes or more are desired when considering post-Contingency remedial actions.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

The PC/TP will coordinate with adjacent system PC/TPs to obtain a list of contingencies on their systems which they have observed may potentially result in reliability impacts on the ITS. These contingencies will be evaluated in the same manner as those events identified in R3.4.

The PC/TP will monitor ITS planning event impacts on Facilities in the adjacent Systems for potential unacceptable performance during R3.1 and R3.2 studies. ITS Contingencies resulting in potential reliability impacts on adjacent PC/TP facilities will be summarized and provided to those adjacent entities during the annual planning process.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Table 1 Extreme Events evaluations are divided into three categories:

1. Planning events that were mitigated with specific system adjustments or operating guides. Those adjustments should be assumed to have not occurred in the planned timeframe.
2. Local area events impacting multiple generation or Transmission facilities.
3. Wide area events impacting generation at two separate stations.

The list of specific contingencies expected to produce more severe impacts will be simulated to cover these Extreme Events. These contingencies will be included in the Planning Assessment as well as the rationale used to identify the contingencies. A study would then be performed under R3.2.

4.0 R4 – Stability Studies

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.1.1 - For normally-cleared, three-phase faults (P1), units will not be allowed to pull out of synchronism. If a unit is determined to pull out of synchronism then a solution to the problem will be included in the stability CAP.

4.1.2 - When generating units become unstable for Planning Events P2 – P7, the apparent impedance swings will be monitored using the generic line relaying model of PSS/E. Impedance swings into the Transmission system which are predicted to trip Transmission system elements other than the generating unit and its directly connected facilities, indicate an unacceptable system performance. If this occurs, a solution will be included in the stability portion of the CAP.

4.1.3 The damping of power oscillations, for planning events P1-P7, will be monitored in the stability simulations. Acceptable damping range is considered to be 3% or greater.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

Studies will be performed to assess the impact of extreme events. See section 3.2 for extreme event selection criteria and modeling.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.3.1 – In all stability simulations remove all elements that the protection system and other automatic controls are expected to remove. Where high speed reclosing is used, both successful and unsuccessful reclosing will be simulated.

Generators will be tripped in the simulations when GSU high side voltages are outside the generator's known or assumed ride through capability limits.

4.3.2 - The expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities will be simulated when such devices impact the study area. Most of the generator controls will automatically be included in the simulations.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

A list of contingencies which are expected to produce more severe system impacts for planning events will be created for evaluation in the stability studies. The list of contingencies is designed to cover each category of planning events from Table 1 as follows:

P0 – Not applicable to stability

PUBLIC DISCLOSURE

- P1.1 – P1.4: A study is conducted which applies a normally-cleared, three-phase fault on every line and transformer in the ITS. These simulations will result in more severe system impacts than faults on generators and shunt reactive devices. Faults on generators will not be as severe because fault clearing will result in tripping a unit which is better for stability. Faults on shunt devices will also not be as severe because tripping a shunt device does not result in weakening the System as compared to tripping Transmission lines.
- P1.5 – Not applicable as HVDC lines are not currently installed in the ITS and no HVDC lines outside of the ITS have been identified as affecting the ITS.
- P2.1 – Opening a line end without a fault will never cause a stability concern that has not already been revealed by faults on the line, as assessed under P1.
- P2.2 – P2.4: Planning events P2.2, P2.3, and P2.4 require single line to ground faults to be applied to bus sections or internal to breakers. These will always be less severe than a three-phase fault which will be covered by the extreme events specified in Table 1 Stability events 2.d and 2.e. When the three-phase faults in the extreme events result in instability, a solution will generally be included in the CAP. If situations should occur where the CAP is not used to address three-phase faults which resulted in instability, then the single line to ground fault will be investigated and appropriate corrective action included as needed.
- P3 – The initial system condition of a generator out is generally not a stability concern because less generation is better for transient stability. A generator out is only a potential stability concern for peak load levels in FIDVR prone areas.
- P4 – Planning events P4.1 through P4.6 require single line to ground faults to be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections with delayed clearing due to a stuck breaker. These will always be less severe than a three-phase fault which will be covered by extreme events specified in Table 1 Stability events 2.a through 2e. When the three-phase faults in the extreme events result in instability, a solution will generally be included in the CAP. If situations should occur where the CAP is not used to address three-phase faults which resulted in instability, then the single line to ground fault will be investigated and appropriate corrective action included as needed.
- P5 – Planning events P5.1 through P5.5 require single-line-to-ground faults to be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections with delayed clearing due to a relay failure. Single line to ground faults will be less severe than a three-phase fault which will be covered by R4.5 extreme events specified in Table 1 Stability events 2.a through 2e. When the three-phase faults evaluated in the R4.5 extreme events result in instability, a solution will generally be included in the CAP. If situations should occur where the CAP is not used to address three-phase faults which resulted in instability, then the single line to ground fault will be investigated and appropriate corrective action included as needed.
- P6.1- P6.3: Studies will be performed with a Transmission element out of service at generating plants on the system. Then a three-phase, normally-cleared fault will be studied on another element at the generating plant. If the generators will not be stable for this contingency, then a system adjustment or a CAP project will be implemented to make sure that the generation will remain stable for the Contingency.

- P6.4 - Not applicable as HVDC lines are not currently installed in the ITS and no HVDC lines outside of the ITS have been identified as affecting the ITS.
- P7.1 - Single-line-to-ground faults will be simulated on two Transmission circuits at a generating plant that share a common tower for greater than one mile. The circuits to be studied will be ones at generating plants which would have more impact on stability.
- P7.2 - Not applicable as HVDC lines are not currently utilized in the ITS and no HVDC lines outside of the ITS have been identified as affecting the ITS.

System Adjustments for stability studies:

Typically, the only P3 or P6 system adjustment which is used in stability studies is dispatching down generation to maintain stability for the next contingency. The adjustments are given to Operations as System Operating Limits (SOL's). These adjustments are ones that can be made within 30 minutes. These issues are generally found for off-peak conditions where generation is available to make up for the generation reductions.

4.4.1 - If any dynamic impacts are found on adjacent systems, the Contingency producing the impacts will be communicated to the Planning Coordinator/Transmission Planner (PC/TP) for that system so they can study the impact to their system. Also, the ITS PC/TP will coordinate with adjacent system PC/TPs to obtain a list of contingencies on their System which they have observed may potentially result in dynamic impacts on the ITS.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

A list of contingencies which are expected to produce more severe system impacts for extreme events will be created for evaluation in the stability studies. Table 1 Extreme Events evaluations are divided into two categories:

1. Planning events that were mitigated using specific system adjustments (resulting in temporary SOL's for Operations). Those adjustments should be assumed not to have occurred. Studies will be made of the consequences of having the next three-phase fault with normal clearing before the system adjustments are made.
2. Three-phase faults with delayed clearing due to a stuck breaker or a relay failure. These contingencies will be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections at or near generating plants. These will have the most severe impact to the stability of the system.

If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

PUBLIC DISCLOSURE

For some Contingencies, primarily three-phase faults with delayed clearing when certain criteria are met, it may be acceptable for generator units to trip with out-of-step protection. If such is the case, then analysis of the same Contingency with a single-line-to ground fault will be performed and noted in the CAP.

5.0 R5 – Voltage Evaluation Criteria

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

The evaluation of power flow steady state voltages and transient voltages (dynamic voltages) are the normal means by which satisfactory voltage performance of the System is determined. System bus voltages must not only be evaluated for normal conditions but also for post-Contingency conditions. System conditions falling within the following performance guidelines will be deemed satisfactory unless tighter guidelines have been identified to accommodate special requirements, including but not limited to governmental regulations, highly voltage-sensitive customer operations, or machine stability limitations.

5.1 Acceptable steady state Transmission Voltage Level Ranges

Table 5.1 A and related notes provide acceptable per unit performance voltage ranges for the pre-Contingency and post-Contingency bus voltage analysis.

Table 5.1 A

Planning Event		500 kV	230 kV	161 kV	115 kV
P0 - No Contingency	Generator High side Bus	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
	Switching Station	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
	Load Serving Bus	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
P1-P2 – Single Contingency	Generator High side Bus	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
	Switching Station	0.97 – 1.075	0.92 – 1.05	0.92 – 1.05	0.92 – 1.05
	Load Serving Bus	0.97 – 1.075	0.92 – 1.05	0.92 – 1.05	0.92 – 1.05
P3-P7 – Multiple Contingency	Generator High side Bus	0.98 – 1.075	0.95 – 1.05	0.95 – 1.05	0.95 – 1.05
	Switching Station	0.97 – 1.075	0.9 – 1.05	0.9 – 1.05	0.9 – 1.05
	Load Serving Bus	0.97 – 1.075	0.9 – 1.05	0.9 – 1.05	0.9 – 1.05

Notes:

- 1) Equipment ratings and/or transformer tap settings may result in tighter ranges at some buses. This includes, but is not limited to voltages at buses with 110 kV rated equipment which typically would result in a reduced high voltage level limit from 1.05 to 1.04.
- 2) For the purpose of voltage level criteria, the generator transmission high side bus should be treated like a load serving bus for the following conditions:
 - a) If no units at a plant are turned on in normal system (no planning contingency in effect) power flow evaluation
 - b) If for single unit plants, for a normal system planning contingency that involves the outage of the same aforementioned unit
 - c) If a plant has been deemed exempt from the NERC Planning Standards requirement of having to hold a voltage schedule
 - d) For low MVA plants (<75 MVA aggregate generation or individual units < 20 MVA) where a plant is defined as one or more units that are on-line in the power flow and are interconnected to the same Transmission bus.
- 3) Exceptions may be considered for plants above 75 MVA that cannot hold voltage schedule for some standard planning contingencies, if:
 - a) Voltage stability margins are above the minimum 5% threshold and
 - b) Power flow analysis indicates that there are no other voltage violations at any load serving buses

5.2 Generator Bus Voltage Levels

The voltage at the generator terminal buses should not exceed the maximum or fall below the minimum allowable voltage limits for any steady state conditions, including both system intact and planning event conditions. It is expected that the generator owner will specify equipment such that the voltage limit range for a generator low-side bus is 0.95 – 1.05 p.u. However, as determined on a case by case basis, reduced ranges may be required. Generator bus voltages falling below the minimum allowable bus voltage will result in tripping of the unit in the study per R3.3.1.1 and R4.3.1.2.

5.3 Nuclear Plant Off-site Source voltages

NERC NUC-001 requires “*Nuclear Plant Generator Operators and Transmission Entities to coordinate for the purpose of ensuring nuclear plant safe operation and shut down*”. The standard further requires “Agreements” to be established which include Nuclear Plant Interface Requirements (NPIRs). The current NPIRs specify acceptable steady state Transmission bus voltage ranges for unit shut-down conditions assuming one unit is undergoing a design basis accident (e.g. loss of cooling event) plus an unrelated worst case generation or Transmission Contingency.

5.4 Steady state Voltage Deviation

The steady state voltage deviation is defined as the difference between pre-Contingency and post-Contingency bus voltages. Acceptable deviation must not result in post-Contingency voltages outside of the acceptable steady state range of the performance Table of 5.1 A.

- o The general screening criteria for post contingency voltage deviation at generator high side buses is:

- No voltage deviation as long as generator reactive requirements are satisfied.
- When generating units are meeting the Southern Company Transmission Policy 9 - Reactive Policy for Generating Facilities Connecting to the Southern Company Transmission System reactive policy, the voltage deviation will be treated the same as networked Transmission buses.
- The general screening criteria for post-Contingency networked Transmission buses is:
 - Switching stations – n/a
 - Load serving stations with voltage regulation equipment - the deviation should be less than 8%.
 - Load serving stations without voltage regulation equipment - the deviation should be less than 5%.
 - In situations where either of these screening criteria are exceeded, the Transmission Planner should coordinate any CAP with the Distribution Provider.
- Stations which become radial as a result of the P2.1 planning event are screened against the same criteria as the post-Contingency networked buses above.
 - Radial station voltage deviations which exceed the defined network bus voltage deviation, but remain above the P0 minimum acceptable voltage, are acceptable.
 - Radial station voltage deviations which result in voltages below the P0 planning event minimum allowable voltage, but remain within the allowable P1-P2 voltage range, will be evaluated for known specific customer voltage deviation requirements.

5.5 Transient (dynamic) voltage response

Summer Peak Demand load levels: For normally-cleared faults (P1-P3), voltages must recover above 80% of the pre-fault voltage within 2 seconds for networked buses, and no units should trip due to low voltage. For lower probability faults, such as three-phase faults with delayed clearing due to a stuck breaker or a protective relay failure (P4-P7), the following should be satisfied:

- (1) All networked Transmission buses should recover to above 80% of the pre-fault voltage within 4 seconds of the initial fault; and
- (2) For the north Georgia area, the East Critical Unit (ECU) point value of units tripped should not exceed the largest ECU point value of the most valuable unit in north Georgia; and
- (3) All networked Transmission buses should recover to normal voltages within a reasonable time in the dynamic analysis.

Off-Peak load levels: For normally-cleared faults (P1-P3), the transient voltage dip at any load bus should not remain below 80% of pre-contingency voltage for more than 40 cycles. This only applies to Off-Peak load levels with a standard load model used for loads.

6.0 R6 – System Instability Evaluation Criteria

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

Steady state:

When performing planning event (or extreme event) assessments, an additional analysis may be needed to simulate potential line opening. If the planning event (or extreme event) results predict significant impacts requiring remedial actions resulting in greater than 300 MW of total load loss (including Consequential and system operator initiated Non-Consequential load shed), or voltage instability as indicated by non-convergent study cases, then a separate steady state analysis is performed to test for potential cascading.

The check for potential cascading Transmission outages assumes no system operator initiated remedial action load shed occurs.

The steady state analysis test for Cascading Transmission Outages is evaluated as follows:

1. For the planning events (or extreme events) which predict significant impacts as described above, the initiating NERC TPL-001 event is modeled and results are reviewed to determine if at least one Transmission Facility is loaded above its rating. If any post-Contingency loading exceeds 110% of the continuous facility rating, then the facility with the highest percent loading is simulated as opening.
2. Analysis of the resulting post-Contingency case to determine if any additional facilities are loaded above 110% of their continuous facility ratings is conducted. If any are loaded above the 110% of the continuous facility rating, then the facility with the highest overload is opened creating a new post-Contingency case and step 2 is repeated until all facilities are within 110% of their ratings. Once all facilities are within 110% of the facility continuous rating, a remedial action load shed is performed. Upon completion of the remedial action load shed, an evaluation of the number of Transmission facilities opened in the simulation and the extent of the area impacted is conducted.

For the purpose of this steady state assessment, the result will be considered potentially cascading if:

- More than three facilities are eventually simulated as being operator opened following the initiating event and prior to a post-Contingency case solution where all facilities were within 110% of their facility rating, or
- The resulting overloaded facilities occur outside of the Southern Reliability area, or
- The study case solution will not converge (solve) due to system conditions such as voltage collapse.

Stability: In addition to the steady state analysis, voltage stability and system angular stability analyses are also conducted.

- Voltage stability analysis is made using P-V curve techniques. Voltage instability is defined as the knee of the P-V curve. The system is planned such that it will operate

with 5% or greater margin from the voltage instability point for single element out Contingencies (P1-P2) and for unit out with single element out Contingencies (P3). For lower probability Contingencies (P4-P7), voltage stability margins should be 2.5% or greater from the voltage instability point.

- All angular stability analyses which include a generic line relay model will determine when impedance swings impact line relaying. For impedance swings into the Zone 1 protection defined by the generic model, it is assumed line relaying will trip the Transmission line. Tripping of three or more Transmission lines in this manner defines cascading for stability analyses. When cascading is detected, a solution will be included in the CAP. If the simulation results in multiple lines being tripped such that an electrical island is created, then this will be considered uncontrolled islanding and a solution will be added to the CAP.

7.0 R7 – Planning Coordination / Transmission Planning Roles and Responsibilities

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

For affiliated operating companies in the SBAA including GPC, SCST Transmission Planning performs the Planning Coordinator and Transmission Planner (PC/TPs) responsibilities for all TPL-001 requirements except those related to short circuit and breaker duty analysis. PC/TP responsibilities include development of study cases, performing planning studies and summary assessments based on coordinated annual 10-year studies, and coordination of any required CAP projects with the respective Transmission Owners (affiliated and also non-affiliated Georgia ITS Participants).

SCS Transmission performs the responsibilities of Planning Coordinator for MEAG per Georgia Power's relationship with MEAG as their contractor for services.

SCS Transmission performs the responsibilities of Planning Coordinator for City of Dalton per Georgia Power's relationship with Dalton Utilities as their Agent.

GTC is registered as a Planning Coordinator.

Short circuit and breaker duty requirements are performed by SCST and OPCo Protection and Control groups. The short circuit requirements of TPL-001 R1, R2.3, R2.6, R2.8, R7 and R8 are provided in "Guidelines for System Modeling and Short Circuit Assessment of the Georgia Integrated Transmission System".

8.0 R8 – Planning Assessment Distribution

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

Studies performed as the basis of the Annual Planning Assessments are generally completed by December 31st of each calendar year. The complete documentation and final Annual Planning Assessments are generally completed by the end of the 1st quarter of each calendar year based on planning studies of the prior year.

- Each ITS Participant will provide its most recent annual Planning Assessment with a summary of the CAP within 90 days of completing the assessment to adjacent PC/TPs.

Other entities with a valid reliability related need may make a written request through the appropriate OASIS site to be provided the most recent Planning Assessment. Within 30 days of this written request, the appropriate entity will provide its most recent annual Planning Assessment with a summary of the CAP.

In either case, those receiving Planning Assessments will be required to meet Critical Energy Infrastructure Information (CEII) requirements, which can be accessed through the appropriate OASIS website.

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

The appropriate entity will provide a documented response within 90 days of receipt of documented comments from recipients of its Planning Assessment consistent with TPL-001 R8.

Attachment A

***Guidelines For System Modeling and Short Circuit Assessment
for the
Georgia Integrated Transmission System***

Issued:6/15/2015

ASSOCIATED NERC STANDARD(S):

TPL-001-4

IMPLEMENTATION:

Phase in of individual TPL-001-4 requirements will be based on the effective dates as defined in TPL-001-4. The implementation dates for the requirements applicable to short circuit portion are listed below.

January 1, 2015 - R1 & R7

January 1, 2016 - R2 & R8

PURPOSE:

This guideline documents the study processes and requirements that form the basis for the Short Circuit Assessment covering the Near-Term (years 1-5) planning horizon to ensure consistency with the NERC reliability standard TPL-001-4.

Guideline

9.0 R1 – System Model Requirement

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.

1.1. System models shall represent:

- 1.1.1. Existing Facilities
- 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
- 1.1.3. New planned Facilities and changes to existing Facilities
- 1.1.4. Real and reactive Load forecasts
- 1.1.5. Known commitments for Firm Transmission Service and Interchange
- 1.1.6. Resources (supply or demand side) required for Load

Southern Company Services Transmission's (SCST) Protection & Control Applications department maintains system modeling data in a form of CAPE database which is used to perform short circuit studies. This database is also referred as base case in this document. The database or base case is consistent with the requirements of NERC standard MOD-032¹.

The system modeling data includes:

1. Existing generation and transmission facilities based on the most recent as-built data provided by Generation Owner (GO) and Transmission Owner (TO). This data is updated on a continuous basis as needed to include ongoing system changes.
2. The transmission system topology, including the most recent Corrective Action Plan (CAP) and other expected transmission improvements, for the Near-Term and Long-Term planning horizon is included in the model. The current forecast of generation expansion is also included.
3. External system model provided by SERC Short Circuit Data Working Group and FRCC.

Information such as load forecast, firm transmission service and interchange etc. are not modeled as they do not have impact on short circuit studies.

10.0 R2 – Annual Short Circuit Assessment and Corrective Action Plan

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

The short circuit portion of the Planning Assessment is prepared annually and references the applicable studies which have been performed. This portion of the assessment documents the assumptions and summarizes the results of the short circuit studies. The studies are used to develop recommendations such as replacement of breaker with higher interrupting capacity and operating procedures. The recommendations made are included in the Short Circuit CAP spreadsheet.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

The short circuit portion of the Planning Assessment for the Near-Term Transmission Planning Horizon is prepared annually and utilizes the applicable current or past studies which have been performed.

Short circuit studies are generally performed for a case in which the short circuit levels are at maximum, i.e., maximum generation, all lines in etc. The study is performed on a first year and last year base case in the Near-Term Planning Horizon effectively covering all years in Near-Term Planning Horizon. The study results are used to determine whether circuit breakers have interrupting capability for faults that they are expected to interrupt.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

Qualifying past studies will be used along with current studies for the short circuit assessment. When past studies are used, documentation will be included in the assessment showing that no material changes have occurred in the system which would affect the results of the study. Also, when past studies are more than five calendar years old, a technical rationale will be provided to show why the study is still valid.

A possible rationale for no material changes would be that there was no addition of transmission elements on the system or a quick study showing that the change in fault current at all transmission buses on the system is minimal compared to previous years.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations.

The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

The short circuit portion of the Planning Assessment is based on current and past studies which have been performed. These study results are used to determine whether circuit breakers have interrupting capability for faults that they are expected to interrupt. If it is determined that the short circuit current that is required to be interrupted by the breaker is higher than the breaker's interrupting capability (such breakers are also known as overstressed breakers), the CAP is developed to rectify the problem. In most cases, the CAP will be to replace the overstressed breaker with higher capacity breaker but may also include an operating procedure. The recommendations made are included in the short circuit CAP spreadsheet. The spreadsheet contains the list of overstressed breakers and actions needed to achieve required system performance.

Each year the entire CAP from the previous year is reevaluated based on any known or forecasted system changes (including modification or retirement of transmission or generation Facilities).

11.0 R7 – SCST Protection & Control Applications roles and responsibilities

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

SCST Protection & Control Applications is responsible for all short circuit study related requirements of TPL-001-4. P&C Application's responsibilities include development of base case, performing short circuit studies, summary assessments and coordination/development of any required CAP. The CAP will be communicated to SCS Transmission Planning to be included in the 10 year transmission expansion plan.

12.0 R8 – Short Circuit Assessment Distribution

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

SCST Protection & Control Applications will provide its most recent Short Circuit piece of Planning Assessment, also referred as Short Circuit Assessment, with a summary of the CAP within 90 days of completing the assessment to adjacent PC/TPs. Other entities with a valid reliability related request will be provided the most recent Short Circuit Assessment already provided to adjacent PC/TPs within 30 days of a request.

Those receiving Short Circuit Assessments will be required to meet Southern Company Critical Energy Infrastructure Information requirements.

Dated records of Assessment transmittal to each appropriate entity:

- within 90 calendar days of completion of the annual Short Circuit Assessment or
- within 30 days of a request to provide the most recent Short Circuit Assessment

will be retained as evidence. The records will be maintained for a minimum of three calendar years prior to the current year.

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

SCST Protection & Control Applications will provide a documented response to address documented comments from recipients of our Short Circuit Assessment under R8 within 90 days of receipt of those comments.

Dated records of comments from and responses to each appropriate entity within 90 calendar days of receipt of an Assessment comment will be retained as evidence. The records will be maintained for a minimum of three calendar years prior to the current year.

DOCUMENT CHANGE LOG:

Version #	Date	Description of Key Change
4.0	June 17, 2015	Complete rewrite to comply with TPL-001-4

I.T.S.PLANNING PROCEDURE NO. 9

GUIDELINES FOR PLANNING
TRANSMISSION SYSTEM FACILITY IMPROVEMENTS
FOR THE
GEORGIA INTEGRATED TRANSMISSION SYSTEM

I.T.S. JOINT SUB-COMMITTEE FOR TRANSMISSION PLANNING

Edwin Galloway 6/17/15
Edwin Galloway – DU / Date

Jeremy Talley 6/17/15
Jeremy Talley – DU / Date

Jack Comer (For Michael Brown) 6/17/15
Michael Brown – GPC / Date

Michael Robinson 6/17/15
Michael Robinson – GPC / Date

Russell Schussler 6/17/15
Russell Schussler – GTC / Date

Joseph E Sowell 6/17/15
Joseph Sowell – GTC / Date

Donald E. Gilbert 6/17/15
Don Gilbert – MEAG / Date

Ben Boucher 6/17/15
Ben Boucher – MEAG / Date

[B3]

BULK POWER TRANSFORMER

LOADING GUIDE

ITS OPERATING PROCEDURE NO. 22
Bulk Power Transformer Loading Guide

Effective Date: March 13, 2000

Revised Date:

Purpose:

These recommendations are intended to be used as a guide for loading bulk power transformers in the Georgia Integrated Transmission System (ITS).

A bulk power transformer is defined as a power transformer having a low voltage side rating of 115kV or above.

The power transformer loading criteria specified in this guide is intended for use in conjunction with a detailed computer analysis (such as PTLOAD™).

The bulk power transformer loading limitations recommended in this guide are primarily intended to be used in transmission planning system studies.

This guide may be used by system operators provided that sufficient real time information is available to monitor a power transformer loaded beyond its nameplate rating during emergency or contingency situations.

IEEE C57.91-1995 (IEEE Guide for Loading Mineral Oil Immersed Transformers) was used for the basis of this document.

General:

Loading a transformer beyond its nameplate rating involves some amount of risk. Risk areas include (from IEEE Std. C57.91-1995, section 4.1):

- Evolution of free gas from insulation of winding and lead connectors
- Mechanical wear effects which may increase with ratings over 100MVA
- Reduced mechanical strength of both conductor and structural insulation
- Permanent deformation of conductors, insulation materials, or structural parts
- Leaking gaskets, loss of oil, and dielectric failure of bushings due to pressure build-up for currents above rating
- Oil expansion due to top oil temperatures over 105° C may result in operation of the pressure relief device and the expulsion of oil
- Voltage regulation through the transformer may increase significantly due to increased loading and possibly dropping power factor

There are situations where the transformer may be operated above its nameplate rating for short periods of times without significantly affecting the life of the transformer winding insulation.

IEEE C57.91-1995, (section 9.1) addresses four (4) types of loading. These types of loading are Normal Life Expectancy rating, Planned Loading Beyond Nameplate rating, Long time Emergency Loading, and Short time Emergency Loading.

This guide addresses *Normal Loading* (Normal Life Expectancy Rating), *Normal Re-Rated Loading* (Planned Loading Beyond Nameplate rating), and *Contingency Loading* (Long time Emergency Loading) criteria, which are to be used for planning purposes. Additionally, the *Emergency Loading* (Short time Emergency Loading) criteria is addressed to assist system operator personnel.

The following assumptions have been made:

- The transformers are 65° C rise rated.
- The temperature will vary cyclically during the day.
- Individual load profile for each location will be used to determine ratings.
- All cooling equipment, all temperature gauges and alarms are or will be maintained in good working order (any re-rating may require inspection of fans and pumps, calibration of temperature gauges, alarm point adjustment, or benchmark dissolved gas in oil analysis).

This guide does not include or addresses the rating of other substation equipment (such as: switches, current transformers, bus conductors, power circuit breakers, line traps, relay settings, jumpers, bushings, etc.) which are an integral part of the substation and must be accounted for in planning studies. The manufacturer should be consulted for information regarding guidelines for recommended loading limits beyond nameplate (particularly if the date of manufacture is after 1975).

Recommendations:

Normal Loading Criteria:

The Normal loading rating should not exceed the temperature limits specified by the transformer manufacturer for normal life expectancy, and it is based on the manufacturer's nameplate ratings.

Normal insulation life expectancy with respect to winding Hot Spot temperature is set at 110° C for continuous operation. Normal life expectancy can also be anticipated for a variable load with a maximum hot spot temperature of 120° C during any 24 hour period.

The Normal Loading Criteria ratings should be used in transmission planning base case models.

Normal Re-Rated Loading Criteria

The Normal Re-Rated Loading Criteria consists of loading the transformer beyond its nameplate ratings while maintaining acceptable life expectancy.

Re-rated values requested for transmission planning base case models will require a load profile for the base case and first contingency conditions in order to perform calculations. The calculation will be in effect for one year and must be re-submitted and re-evaluated annually.

Re-rated loading may exceed the transformer nameplate rating as long as none of the following parameters are exceeded:

- The load and ambient temperature will be cyclical daily. The *average* ambient temperature for a 24-hour period should not exceed 32° C (89.6° F).
- The maximum load will not exceed 115% of top nameplate rating.
- The top oil temperature shall not exceed 100° C.
- The loss of winding insulation life shall not exceed 0.0254% (150,000h life) per 24 hour period. This is based on the criteria that the winding hot spot temperature will not be maintained in the 120 – 130° C range for more than 4 hours daily.

The Re-rated Loading Criteria rating may be used in transmission planning base case models, on isolated cases, with the limitations indicated above.

Contingency Loading Criteria:

The Contingency loading rating will be applied for abnormal system loading conditions (contingencies), which may persist for some period of time. It is expected that such occurrences be rare.

Contingency loading may exceed the transformer nameplate rating as long as none of the following parameters are exceeded:

- The load and ambient temperature will be cyclical daily. The *average* ambient temperature for a 24-hour period should not exceed 32° C (89.6° F).
- The maximum load will not exceed 130% of top nameplate rating.
- The top oil temperature shall not exceed 110° C.
- The loss of winding insulation life shall not exceed 0.0638% (150,000h life) per 24 hour period. This is based on the criteria that the winding hot spot temperature will not be maintained in the 130 – 140° C range for more than 6 hours daily, and the 120 - 130° C range for more than 4 hours daily or not to exceed 10 hours above 120° C. The winding hot spot temperature shall never exceed 140° C.

The Contingency loading rating should be used in planning contingency models.

Emergency Loading:

Emergency loading is heavy loading brought about by the occurrence of one or more unlikely events that seriously disturb normal system loading. It is expected that this type of loading can be reduced to at least a Contingency loading within one (1) hour.

Emergency loading may exceed the transformer nameplate rating as long as the following parameters are not exceeded:

- The load and ambient temperature will be cyclical daily. The *average* ambient temperature for a 24-hour period should not exceed 32° C (89.6° F). The system operator shall review actual temperature and pre-loading conditions for each specific situation.
- The maximum load will not exceed 130% of top nameplate rating.
- The average winding hot spot temperature shall never exceed 140° C.
- The top oil temperature shall not exceed 110° C.
- The loss of winding insulation life shall not exceed 0.1245% (150,000h life) per 24 hour period.

The Emergency Loading ratings should not be used by Transmission planners.

ITS JOINT SUBCOMMITTEE FOR OPERATIONS

ITS OPERATING PROCEDURE No. 22

BULK POWER TRANSFORMER LOADING GUIDE

Christopher D. Brewton 4/12/00

Christopher D. Brewton - Dalton Utilities / Date

W.R. Seaton 4/12/00

W. R. Seaton - Dalton Utilities / Date

Albert E. Hay 4/12/00

Albert E. Hay - GPC / Date

Randy W. Kirkus 4/12/00

Randy W. Kirkus - GPC / Date

Seth W. Brown 4-12-00

Seth W. Brown - GTC / Date

Gregory S. Ford 4-12-00

Gregory S. Ford - GSOC / Date

Linda T. Gray 4-12-00

Linda T. Gray - MEAG Power / Date

Larry G. Stephenson 4/12/00

Larry G. Stephenson - MEAG Power / Date

[C]

**TRANSMISSION SYSTEM
OPERATIONS**

[C1]

2018 SUMMER OPERATING STUDY

INTRODUCTION

The purpose of the Summer Operating Study ("SOS") is to assist System Operations in preparing for operating conditions that could occur during the summer period and prepare the System Operators to deal with unplanned system events, including unexpected outages, major equipment failures, and certain extreme events.

The SOS identifies thermal and voltage limitations on the Georgia Integrated Transmission System (ITS) and the Savannah area transmission network (SAV) during normal and/or contingency conditions for the expected peak load periods.

The SOS evaluation is performed in the spring. The output is summarized in a database that includes line name, relevant contingencies, relevant case study for worst violation, and solutions for remediation. Thermal loading limitations are listed in Section III and voltage limitations are listed in Section IV. System operating procedures are noted where they mitigate identified transmission system limitations.

The following Summer Base Cases were studied in 2018:

1. 2018 Summer Peak Load Cases

A set of 2018 summer base cases was created using a modified dispatch of the generating units that were expected to be available for summer 2018. Normal output levels for the North Georgia hydro units were reduced to more closely approximate typical peak-hour operation, per System Operations recommendations.

Load levels and contracted sales to the Florida utilities were set as follows by case:

D = Daylight Shoulder (93% load, [REDACTED], Hydro motoring, Solar On)

H = Shoulder (93% load, [REDACTED], Hydro motoring, Solar Off)

S = Summer Peak (100% load, [REDACTED], Hydro On, Solar On)

T = Hot Weather (107% load, [REDACTED], Hydro On, Solar On)

2. Generator Unit-Out Cases

Certain generator single-unit-out cases were created using D, H, and S base cases (Hot Weather cases are not studied with additional units out). Additionally, certain multiple-unit-out cases were created for units with possible common failure modes (such as a single equipment failure at West Point Dam). Specific unit-out cases are listed below.

3. Hydro cases

Daylight Shoulder and Shoulder cases were created to study the system impact for multiple hydro units running at their minimum flow rate, providing limited MW support to the system while still providing VAR support.

4. West-East Flow cases

Summer Peak, Shoulder, and Daylight Shoulder West-East Flow cases were created to study the impact of high import levels into the state of Georgia from neighboring utilities from the West. Cases were created assuming an increase in generation from neighboring Alabama and Mississippi generation units while Georgia generation units

were reduced to simulate similar conditions that have been seen in real-time operations scenarios during maintenance and other unexpected outages.

5. Extreme Event cases

Summer Peak, Daylight Shoulder, and Shoulder cases were created to study certain low-probability events, including possible bus tie breaker failures, high profile bus differentials, and loss of major system right-of-ways.

All of these cases were economically dispatched using Southern Company's Designated Network Resources for 2018 and the individual generating units' cost data.

SUMMER OPERATING STUDY ASSUMPTIONS

The following assumptions were used for the 2018 Summer Operating Study:

Network Operational Assumptions

1. Unless otherwise stated, if the thermal limitation(s) occurs in the normal dispatch, assume the problems occur in all dispatches during peak loading.
2. For a given monitored transmission element, only the flows for the worst contingency outage of a transmission element are listed.
3. Transmission element ratings used for this report use the 95°F ambient adjusted ratings as used by Transmission Planning except for the Hot Weather (T) scenario, which uses the 104°F ambient adjusted ratings.

Screening Procedure

1. SOS Load Flow Cases:

- D, H, S, T base cases as defined above
- D, H, S cases with additional single and multiple generator unit outages, units detailed below
- Summer Peak (S) Special Hydro cases
- Maximum West-East flow case
- Special Extreme Event cases

2. Screen Flags:

- Thermal loading: >100% of facility rating
- Voltage: < 95% or > 105% of nominal voltage or ≥ 5% deviation

3. Situations Studied:

- No element out using Rate A (104°F ambient) in normal-weather peak, all cases
- No element out using Rate B (95°F ambient) in normal-weather peak, all cases
- Contingency N-1 (one element out) using Rate B (95°F ambient) in all cases excluding Hot Weather (T) and Extreme Event cases
- Contingency (one element out) using Rate B (95°F ambient) in re-dispatched cases with one or more generation units out (listed below) in S, D, and H cases

4. Unit Out Summary:

One Unit Off	Case Name
Basecase, no units out	BASE
Bowen Unit 1 outage	BOW1
Bowen Unit 4 outage	BOW4
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
Hammond Unit 4 outage	HAM4
Hatch Unit 1 outage	HAT1
Hatch Unit 2 outage	HAT2
[REDACTED]	[REDACTED]
Jack McDonough Unit 4 outage	MCD4
Jack McDonough Unit 6 outage	MCD6
[REDACTED]	[REDACTED]
Vogtle Unit 1 outage	VOG1
Vogtle Unit 2 outage	VOG2
Yates Unit 7 outage	YAT7

Multiple Units Off	Case Name
Franklin Unit 1,2,3 outage	FRKX
West Point Dam Hydro Units outage	WPD1

5. Special Sensitivity cases – Hydro and Import

Sensitivity	Case Name
Hydro unit minimum flow	HYDRO
Maximum West-East flows	MXWEST_Mod

6. Extreme Events

Elements Out	Case Name
[REDACTED]	[REDACTED]

**2018 GEORGIA LIMITING FACILITIES
CONTINGENCY THERMAL LIMITATIONS
CONTINGENCY VOLTAGE LIMITATIONS**

Pages 5-22 are redacted in their entirety.

[C2]

2016 - 2018

SYSTEM PERFORMANCE

**2016-2018 Major Outages
Major Event Summary**

Pages 1-9 are redacted in their entirety.

[D]

GEORGIA ITS

[D1]

**GEORGIA ITS
TEN YEAR TRANSMISSION
EXPANSION PLAN
(2019 – 2028)**

Georgia Projects

(Includes ITS & Savannah Projects)

2019 – 2028

Transmission  *Planning*

Southern Company Services

FALL 2018



I. CONTENTS

I. GA ITS EXECUTIVE SUMMARY 5

A. Summary of Georgia ITS Transmission Additions.....6

B. Georgia ITS 10 Year Expansion Plan Projects List7

C. Cancelled Projects List – Removed from the Current 10 Year Expansion Plan11

D. Completed Projects List – Removed from the Current 10 Year Expansion Plan12

II. Transmission Planning Process Description..... 14

A. Annual Planning Process and Base Cases14

 Maintaining System Models14

 Load Forecast16

 Generation17

 Normal Open Points.....17

III. PERFORMANCE CRITERIA 18

A. Steady State Analysis18

 Steady State Sensitivity Analysis23

 Steady State Equipment Sparing Analysis.....23

 Steady State Coordination with Adjacent Systems.....23

B. Stability Analysis24

 Stability Past Studies28

 Stability Sensitivity Analysis (Near-Term Planning Horizon).....28

 Long-Term Stability Analysis28

C. Short Circuit Analysis29

D. Interface Transfer Capability Assessments.....29

IV. ANALYSIS RESULTS 31

A. Operating Guides31

B. Stability Project Details.....32

 NE GA HYDRO STABILITY (OUT OF STEP PROTECTION INSTALLATIONS)33

 VOGTLE PILOT PROTECTION SCHEME.....34

 WADLEY PRIMARY 500/230KV PROJECT (PHASE 2).....35

C. Short Circuit Project Details.....36

 No Short Circuit Projects in Current 10 Year Plan.....37

D. Interface Transfer Capability Project Details.....38

AVALON JUNCTION - BIO 115 KV REBUILD39

E. Steady State Project Details.....40

ATHENA - EAST WATKINSVILLE 115KV RECONDUCTOR.....41

BARNEYVILLE - DOUGLAS 115 KV UPGRADE (NV#1 - NV #2).....42

BLAKELY PRIMARY - MITCHELL 115KV LINE REBUILD43

BLANKETS CK.-WOODSTOCK 115-KV LN REBLD, (WOODSTK-LITTLE RVR).....44

BRUNSWICK - ST SIMONS 115 KV LINE RECONDUCTOR.....45

CENTER PRIMARY - WEYERHAEUSER 115KV CONDUCTOR UPGRADE.....46

CLAXTON - STATESBORO PRIMARY 115 KV RECONDUCTOR47

DANIEL SIDING - LITTLE OGEECHEE 115-KV RECONDUCTOR.....48

DEAL BRANCH - SYLVANIA 115-KV UPGRADE49

DUM JON – FORT GORDON #2 115 KV NON-CONDUCTOR UPGRADES.....50

EAST SOCIAL CIRCLE - STANTON SPRINGS 115 KV RECONDUCTOR.....51

EVANS PRIMARY - THOMSON PRIMARY 115KV RECONDUCTOR.....52

FIRST AVENUE REPLACE LOWSIDE SWITCHES.....53

GOAT ROCK - RETIRE 115KV 60MVAR CAPACITOR BANK54

GORDON - N. DUBLIN (N. DUBLIN - EVERGRN CH) 115 KV UPGRADE55

GORDON - SANDERSVILLE #1 115 KV LINE UPGRADE.....56

GRANITEVILLE - SOUTH AUGUSTA 115 & 230-KV TIE LINES57

GTC: BLAKELY PRI - DAWSON PRI. 115KV LINE58

GTC: BONAIRE PRIMARY 115 KV JUMPER REPLACEMENTS.....59

GTC: TIGER CREEK 230 KV SERIES REACTORS60

JONESBORO - OHARA 230-KV RECONDUCTOR & UPGRADES.....:61

KETTLE CREEK - PINE GROVE 115KV LINE UPGRADE PHASE ONE.....62

KETTLE CREEK - PINE GROVE 115KV LINE UPGRADE PHASE TWO63

LAWRENCEVILLE - NORCROSS 230KV LINE RECONDUCTOR64

LINE CREEK - FAIRBURN 2 115KV LINE UPGRADE65

LIVE OAK-STATESBORO PRI & LIVE OAK-WADLEY PRI 115KV UPGRADES66

MCEVER ROAD - SHOAL CREEK 115KV REBUILD - PHASE 267

MCINTOSH 230/115-KV TRANSFORMER REPLACEMENT.....68

MEAG: AULTMAN ROAD - BONAIRE PRIMARY 115 KV RECONDUCTOR II69

MEAG: AULTMAN ROAD - FORT VALLEY #1 115 KV LINE UPGRADE.....70

MITCHELL 230KV REBUILD71

NORTH AMERICUS - PERRY 115 KV LINE REBUILD72

NORTH AMERICUS - PERRY 115 KV RELAYING AND NON-COND UPGRADES73

I. GA ITS EXECUTIVE SUMMARY

The results of the studies performed on the GA ITS portion demonstrate that required performance criteria are met or a project or operating guide have been developed to address any identified system deficiencies.

A Summary of Georgia ITS Transmission additions starts on the next page, followed by the List of the Georgia ITS 10 Year Expansion Plan Projects.

This group of projects and operating guides, found in Section IV – ANALYSIS RESULTS, is reassessed each year to confirm continued need, timing, and scope for previously identified projects until projects have transitioned from planning to a committed project. These reassessments also investigate potential need for additional projects or modification to projects currently included. Any operating guides identified to address a violation is approved by Georgia Power Operations. The transmission improvements are submitted to ITS Participants for budgetary approval.

The following information is included for each project:

- 1) project justification,
- 2) schedule for implementation (start date), and
- 3) expected required in-service date.

For transmission improvements, lead times necessary to implement plans are considered to ensure the expected required in-service date can be met.

A. Summary of Georgia ITS Transmission Additions

Table 1 Summary of Georgia ITS Transmission Additions

	First 5 Years		Total 10 Years	
New Transmission Lines Requiring New Right of Way				
Voltage (kV)	Lines	Miles	Lines	Miles
500	0	0	0	0
230	2	19.2	2	19.2
115	1	5	1	5
Total	3	24.2	3	24.2

Transmission Lines to be Rebuilt / Reconductored on Existing Right-of Way				
Voltage (kV)	Lines	Miles	Lines	Miles
500	0	0	0	0
230	2	6	2	12
115	17	165.5	17	214
Total	19	171.5	19	226

Transmission Lines Upgraded on Existing Right-of Way				
Voltage (kV)	Lines	Miles	Lines	Miles
500	0	0	0	0
230	0	0	0	0
115	10	103.8	10	125.5
Total	10	103.8	10	125.5

Transformers to be installed (low side \geq 115kV)				
	Units		Units	
New	3		3	
Upgrade	1		1	

New Capacitor Banks to be Installed				
Voltage (kV)	Units	MVAR	Units	MVAR
230	0	0	0	0
115	0	0	0	0

New Series Reactors to be Installed				
Voltage (kV)	Units		Units	
230	1		1	

B. Georgia ITS 10 Year Expansion Plan Projects List

Table 2 Ga ITS 10 Year Plan Project List below briefly lists projects in the 10 Year Expansion Plan (details for each project are in later sections).

Table 2 Ga ITS 10 Year Plan Project List

Zone	TEAMS Number	Project Name	Need Date 2018	Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Estimated Cost - ITS Assigned	Totals
201	16278	BLANKETS CK.-WOODSTOCK 115-KV LN REBLD, (WOODSTK-LITTLE RVR)	06/01/2024	GPC	██████████	██████████	██████████	██████████	██████████	██████████
201	13653	NORTH MARIETTA - SMYRNA (BLACK & WHITE) 115KV RECONDUCTORS	06/01/2025	GPC	██████████	██████████	██████████	██████████	██████████	██████████
202	10129	LAWRENCEVILLE - NORCROSS 230KV LINE RECONDUCTOR	06/01/2022	GPC	██████████	██████████	██████████	██████████	██████████	██████████
208	16969	██████████	██████████	GPC	██████████	██████████	██████████	██████████	██████████	██████████
208	10452	JONESBORO - OHARA 230-KV RECONDUCTOR & UPGRADES	06/01/2024	GPC	██████████	██████████	██████████	██████████	██████████	██████████
208	17791	LINE CREEK - FAIRBURN 2 115KV LINE UPGRADE	6/1/2020	GPC	██████████	██████████	██████████	██████████	██████████	██████████
211	17678	POSSUM BRANCH 230/115 KV PROJECT	05/01/2022	GTC	██████████	██████████	██████████	██████████	██████████	██████████
212	09603	ATHENA - EAST WATKINSVILLE 115KV RECONDUCTOR	06/01/2021	GPC	██████████	██████████	██████████	██████████	██████████	██████████
212	17294	AVALON JUNCTION - BIO 115 KV REBUILD	06/01/2022	GPC	██████████	██████████	██████████	██████████	██████████	██████████
212	16878	CENTER PRIMARY - WEYERHAEUSER 115KV CONDUCTOR UPGRADE	03/01/2019	GPC	██████████	██████████	██████████	██████████	██████████	██████████
212	17798	EAST SOCIAL CIRCLE TO STANTON SPRINGS 115 KV	05/01/2021	GPC	██████████	██████████	██████████	██████████	██████████	██████████
212	10194	MCEVER ROAD - SHOAL CREEK 115KV REBUILD - PHASE 2	06/01/2027	GPC	██████████	██████████	██████████	██████████	██████████	██████████
212	14922	NE GA HYDRO STABILITY (OUT OF STEP PROTECTION INSTALLATIONS)	05/01/2019	GPC	██████████	██████████	██████████	██████████	██████████	██████████
213	14814	FIRST AVENUE REPLACE LOWSIDE SWITCHES	06/01/2026	GPC	██████████	██████████	██████████	██████████	██████████	██████████
213	15518	GOAT ROCK - RETIRE 115KV 60MVAR CAPACITOR BANK	12/31/2019	GPC	██████████	██████████	██████████	██████████	██████████	██████████

213	10391	NORTH AMERICUS - PERRY 115 KV LINE REBUILD	06/01/2020	GPC							
213	17244	NORTH AMERICUS - PERRY 115 KV RELAYING AND NON-COND UPGRADES	06/01/2020	GPC							
214	17541			GPC							
214	11694	GORDON - N. DUBLIN (N. DUBLIN - EVERGRN CH) 115 KV UPGRADE	06/01/2022	GPC							
214	10442	GORDON - SANDERSVILLE #1 115 KV LINE UPGRADE	06/01/2022	GPC							
214	14567	GTC: BONAIRE PRIMARY 115 KV JUMPER REPLACEMENTS	06/01/2024	GTC							
214	15371	GTC: TIGER CREEK 230 KV SERIES REACTORS	06/01/2023	GTC							
214	13787	MEAG: AULTMAN ROAD - BONAIRE PRIMARY 115 KV RECONDUCTOR II	06/01/2022	MEAG							
214	15306	MEAG: AULTMAN ROAD - FORT VALLEY #1 115 KV LINE UPGRADE	06/01/2020	MEAG							
214	15698	SINCLAIR DAM - WARRENTON 115KV RECONDUCTOR PHASE I	06/01/2024	GPC							
214	17799	SINCLAIR DAM - WARRENTON 115KV RECONDUCTOR PHASE II	06/01/2028	GPC							
215	16307	DUM JON - FORT GORDON #2 115 KV NON- CONDUCTOR UPGRADES	06/01/2028	GPC							
215	13104	EVANS PRIMARY - THOMSON PRIMARY 115KV RECONDUCTOR	06/01/2020	GPC							
215	16582	GRANITEVILLE - SOUTH AUGUSTA 115 & 230-KV TIE LINES	06/01/2020	GPC							
215	17790	VOGTLE PILOT PROTECTION SCHEME	06/01/2020	GPC							
215	14663	WADLEY PRIMARY 500/230KV PROJECT (PHASE 2)	06/01/2021	MEAG							
216	11246	BARNEYVILLE - DOUGLAS 115 KV UPGRADE (NV#1 - NV #2)	06/01/2020	GPC							

216	15368	BLAKELY PRIMARY - MITCHELL 115KV LINE REBUILD	6/1/2020	GPC							
216	17573	GTC: BLAKELY PRI - DAWSON PRI. 115KV LINE	11/01/2020	GTC							
216	15687	KETTLE CREEK - PINE GROVE 115KV LINE UPGRADE PHASE ONE	6/1/2023	GPC							
216	16589	KETTLE CREEK - PINE GROVE 115KV LINE UPGRADE PHASE TWO	6/1/2028	GPC							
216	16528	MITCHELL 230KV REBUILD	01/09/2019	GPC							
218	12115	BRUNSWICK - ST SIMONS 115 KV LINE RECONDUCTOR	06/01/2025	GPC							
218	13096	CLAXTON - STATESBORO PRIMARY 115 KV RECONDUCTOR	06/01/2019	GPC							
218	11238	DANIEL SIDING - LITTLE OGEECHEE 115-KV RECONDUCTOR	06/01/2027	SAV							
218	12095	DEAL BRANCH - SYLVANIA 115-KV UPGRADE	06/01/2023	GPC							
218	13024	LIVE OAK-STATESBORO PRI & LIVE OAK-WADLEY PRI 115KV UPGRADES	06/01/2023	GPC							
219	11662	MCINTOSH 230/115-KV TRANSFORMER REPLACEMENT	06/01/2019	SAV							
	43										

C. Cancelled Projects List – Removed from the Current 10 Year Expansion Plan

Table 3 Cancelled Projects – Removed from the Current Ten Year Plan below briefly lists removed projects from previous year’s 10 Year Expansion Plan.

Table 3 Cancelled Projects – Removed from the Current Ten Year Plan

Zone	TEAMS Number	Project Name	Last Year's Need Date	Sponsor	Estimated Cost - GPC	Estimated Cost - GTC	Estimated Cost - MEAG	Estimated Cost - DU	Estimated Cost - ITS Assigned	Totals
201	12063	DOUGLASVILLE - POST RD 115 KV REBLD. PH-2,(DGLS TO ANEW J)	6/1/2022	GPC						
202	17387	CUMMING BUS AND JUMPER REPLACEMENT	6/1/2025	GPC						
202	13614	HOLLY SPRINGS-HOPEWELL 115KV RECONDUCTOR	6/1/2027	GPC						
206	10899	AUSTIN DRIVE - MORROW 115-KV RECONDUCTOR	6/1/2025	GPC						
206	16919	BOULEVARD - NORCROSS 115KV LINE SWITCH REPLACEMENTS	6/1/2025	GPC						
206	16404	CLARKSTON - SCOTSDALE 115KV LINE UPGRADE	6/1/2024	GPC						
206	12602	KLONDIKE - MORROW 230KV LINE RECONDUCTOR	6/1/2024	GPC						
208	17004	GTC: MCDONOUGH - SOUTH GRIFFIN 115 KV RECONDUCTOR	6/1/2025	GTC						
208	12609	JONESBORO - O'HARA 230 KV RECONDUCTOR PHASE 2	6/1/2021	GPC						
208	15239	S. COWETA - S. GRIFFIN 115KV LN. RECOND, (S.COW-BRKS)	6/1/2023	GPC						
211	17082	COD: COOSAWATTEE - EAST DALTON 115 KV RECONDUCTOR	6/1/2023	Dalton						
211	15369	COD: DALTON - EAST DALTON (B&W) 115 LINE RECONDUCTOR/BUS REBUILD	6/1/2027	Dalton						
211	15879	POSSUM BRANCH - YATES 115KV RECONDUCTOR (YATES - CLEM)	6/1/2024	GPC						
212	15411	BIO 115KV BREAKER 123208 REPLACEMENT	6/1/2020	GPC						
212	14264	SOUTH HALL 500/230KV 2ND AUTO BANK	6/1/2027	GPC						
216	14204	OFFERMAN 230/115 KV AUTOBANK REPLACEMENTS	6/1/2020	GPC						
219	12159	COLEMAN 115/46-KV PROJECT	6/1/2022	SAV						
219	17014	MCINTOSH 2ND BANK INSTALLATION	6/1/2026	SAV						
219	16442	RICE HOPE CAPACITOR - PHASE 2	6/1/2027	GPC						

D. Completed Projects List – Removed from the Current 10 Year Expansion Plan

Table 4 Completed Projects – Removed from the Current Ten Year Plan below, briefly lists projects removed from the previous year's 10 Year Expansion Plan due to In Service or Construction Completion.

Table 4 Completed Projects – Removed from the Current Ten Year Plan

Zone	TEAMS Number	Project Name	Last Year's Need Date
206	14266	MORROW SWITCH REPLACEMENTS (KLONDIKE 230 KV LINE)	6/1/2018
212	15521	COD: DALTON - OOSTANAULA 115 KV LINE RECONDUCTOR	6/1/2018
213	15815	LAGRANGE PRIMARY: RELAY MODIFICATION AND NEW CONTROL HOUSE	12/31/2018
213	11286	MEAG: CRISP #2 BREAKER ADDITION	6/1/2018
215	15626	MEAG: WADLEY PRIMARY SUBSTATION MODERNIZATION	12/31/2018
215	11285	VOGTLE 3&4 NETWORK IMPV (THOMSON - VOGTLE 500 KV LINE)	12/31/2017
219	15247	DEAN FOREST - MILLHAVEN ANNEX 115 KV LINE	12/31/2018

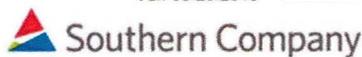
Figure 1 SCS Transmission Planning - East Responsibilities
 Transmission Planning - East Responsibilities 2018

Project Managers



Northwest (Zone 211)	Metro East (Zone 206)	Northwest (Zone 212)	Coastal (Zone 218)
Metro West (Zone 201)	Metro South (Zone 208)	East (Zone 215)	Savannah (Zone 219)
Metro North (Zone 202)	West (Zone 213)	Central (Zone 214)	South (Zone 216)

Ver: 08/20/2018



II. TRANSMISSION PLANNING PROCESS DESCRIPTION

A. Annual Planning Process and Base Cases

The Transmission Planning process performed by Southern Company Services - Transmission (SCST) Transmission Planning for the 10-year planning horizon is a continual process. The process ensures that the Georgia Integrated Transmission System (ITS) participants have all the information necessary to develop projects for identified system limitations to ensure compliance with all NERC Planning Standard requirements, and in time to meet individual participant budget and scheduling needs. The ITS Joint Committee for Planning and Operations will determine which ITS Participant will have construction and ownership responsibilities based upon a full consideration of surrounding issues including, but not limited to, facility ownership and the ITS parity forecast.

This report summarizes Planning Coordinator (PC) and Transmission Planner (TP) planning studies performed by SCST specifically for the Georgia ITS as described in the *Guidelines for Planning Transmission System Facility Improvements* and is consistent with the NERC TPL-001-4 Standard ("Standard").

The following sections provide an overview of maintaining system models, the detailed studies performed, which includes steady state, stability, and short circuit studies, and the resulting Projects and Operating Guides for the mitigation of identified System deficiencies.

Maintaining System Models

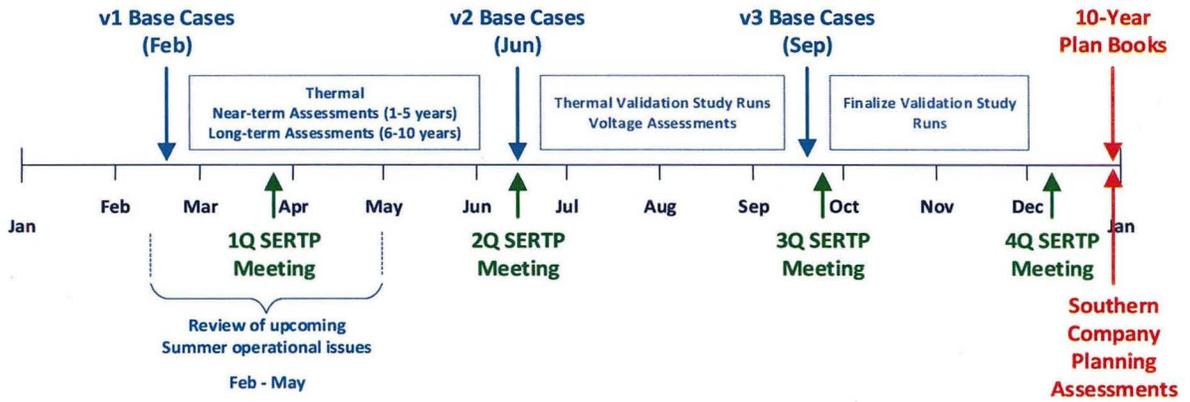
The detailed studies are performed on Transmission System models ("base cases") which are updated annually based on the current 10-year forecast for Southern Balancing Authority Area (SBAA) load and generation required to serve the load. The base cases use data consistent with that provided in accordance with MOD-032, supplemented by other sources as needed, including items represented in the Corrective Action Plan (CAP) and projected System conditions. The base cases include the latest available external representation of the Eastern Interconnection which is generally obtained from the Multi regional Modeling Working Group or SERC Reliability Corporation (SERC) Long Term Study Group. The base cases include the following [Requirement 1]:

1. Existing facilities.
2. Known outages of generation or Transmission Facilities with a duration of at least six months. All outages meeting this criterion in the Near-Term Transmission planning horizon were modeled with the impacted equipment out-of-service as described in R1 in the Standard.
3. New planned Facilities and changes to existing Facilities. These Facilities are rated in accordance with NERC Reliability Standard FAC-008-3.

4. Real and reactive Load forecasts are provided for each Load Serving Entity within Southeastern Sub-Region in SERC.
5. Known commitments for Firm Transmission Service and Interchange.
6. Resources required for Load.

The model of the Southern Balancing Authority Area (SBAA) is constantly changing. Computer models, or base cases, of the system are created on an as needed basis at least twice annually on a schedule like the one shown in Figure 2 below. This ensures that as projects are identified they are included in the analysis of future years.

Figure 2 Annual Base Case Release and Study Schedule



Load Forecast

Refer to the Load Forecast table below for summer peak load projections by year.

Table 5 2018 Series ITS Load Forecast

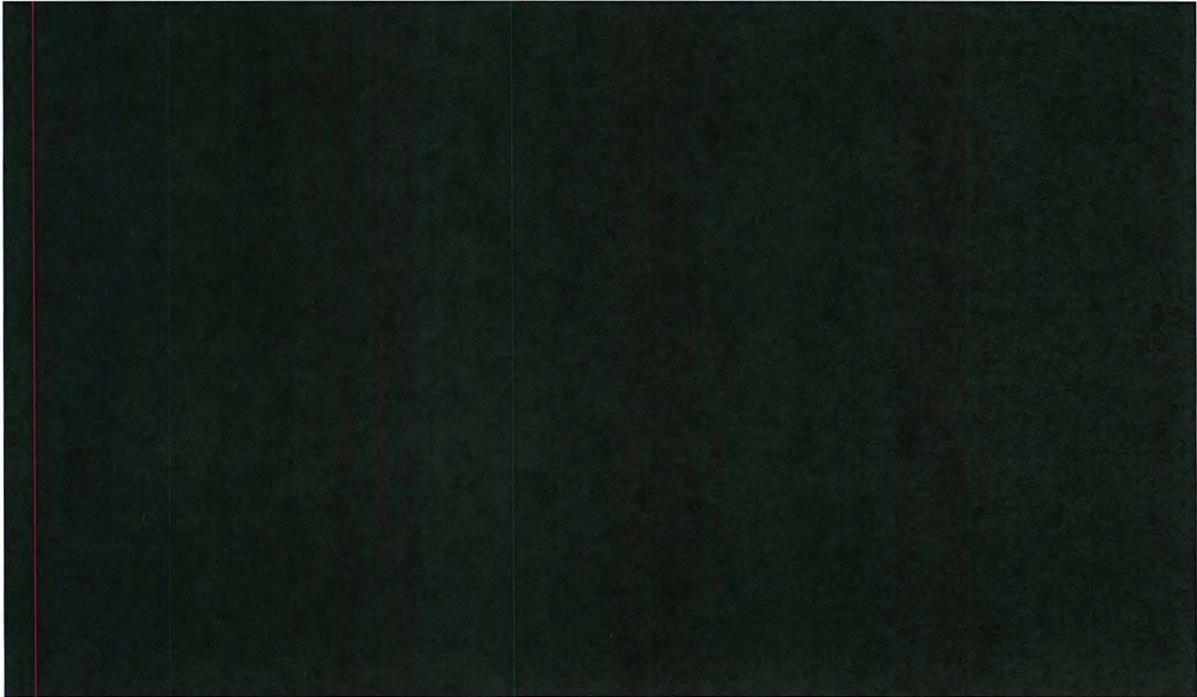
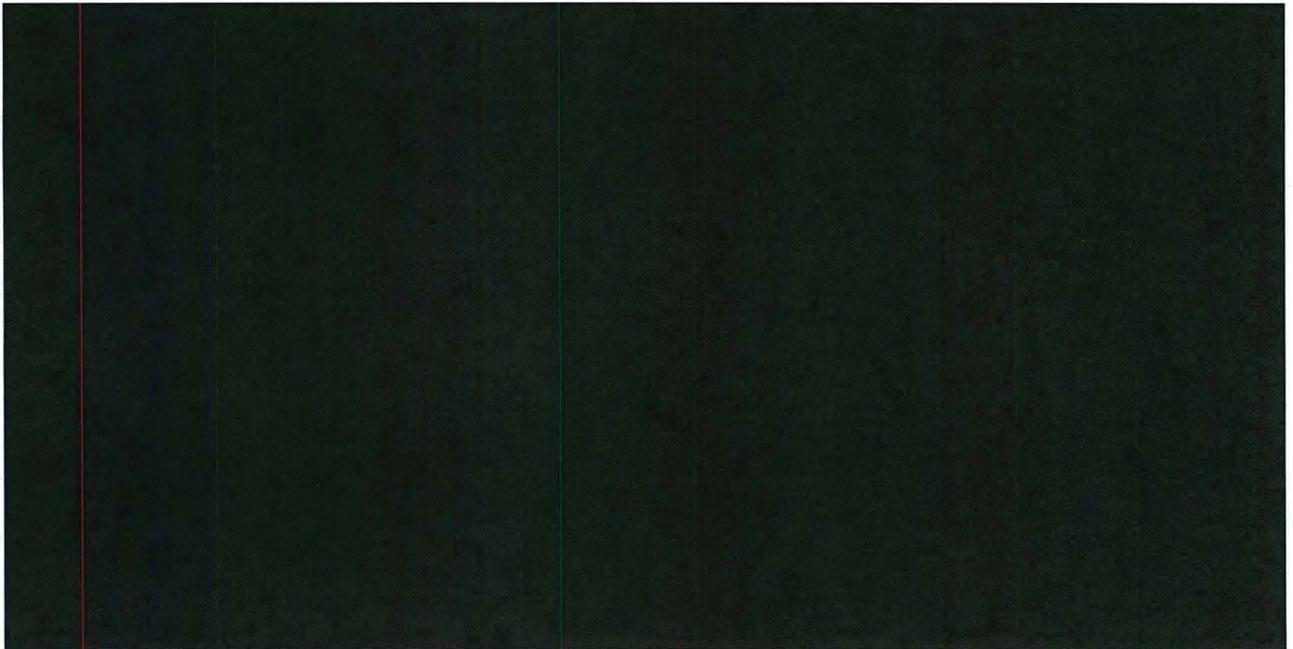
A large rectangular area of the page is completely redacted with a solid black fill, obscuring the data from Table 5.

Figure 3 Total 2018 Series ITS Summer Coincident at the Generator



Load Forecast by Zone in Models

Table 6 10 Year Load Forecast by Zone

ZONE	REGION	2018 MW	2028 MW	10 YEAR GROWTH %	COMPOUND AGR %
201	METRO WEST				
202	METRO NORTH				
206	METRO EAST				
208	METRO SOUTH				
211	NORTHWEST				
212	NORTHEAST				
213	WEST				
214	CENTRAL				
215	EAST				
216	SOUTH				
218	COASTAL				
219	SAVANNAH				
TOTAL					

Source: Load allocation data in PSSE to model results matching Total ITS Coincident Load Forecast @ Sub High-side

Generation

Another key modeling assumption made in case development is generation resources. Future generation assumptions for native load resources for Southern Company, GTC, MEAG, and Dalton are shown in the table in Section VI Generation Assumptions. The table lists units and purchased power agreements, for all parties at the beginning of the year. The dispatch program commits sufficient resources to satisfy the load and reserve requirements for each company in each base case or unit-out case, then adjusts the output level for each generator in the most economical manner.

Normal Open Points

The ITS evaluates normal open point configurations on the Summer Cases. The ITS has alternative transmission service paths to some loads that have radial service. The function of these alternative service paths is to shift load from one circuit path to another should the primary service path be out of service. These alternative service paths cannot remain closed without also opening the primary service path because this new configuration’s system protection will not adequately protect the transmission line if operated as a network transmission line and could cause network load flow constraints.

If a normal open point change is desired, Operations and Planning will evaluate the proposed new system to ensure that the system can accommodate the request prior to reconfiguration.

III. PERFORMANCE CRITERIA

A. Steady State Analysis

Steady state analyses were conducted to consider TPL-001-4 Table 1 Category P0-P7 Planning Events and Extreme Events in both the near-term and longer-term planning horizons for both peak and off-peak loading models. The System Peak loading model represents summer conditions. The System Shoulder loading models represent 93% of summer peak demand with hydro generation motoring off-line and includes models with solar facilities either on or off-line. This off-peak load assumption was anticipated to result in the highest off-peak system stress with a significant portion of energy-limited resources projected to be off-line. An additional series of System Off-Peak cases representing 70% of the summer peak demand were evaluated. All System peak and Off-Peak cases are evaluated using Rate B (95°F ambient temperature). [Requirement 2 Parts 2.1.1, 2.1.2, and 2.2.1]

Additionally, a Hot Weather case representing 107% of system peak is evaluated under ITS procedures using Rate A (104°F ambient temperature) for all equipment rating used.

All projects resulting from Steady State analysis to address any identified deficiencies have been added to the list of projects in Section IV Steady State Project Details.

Table 7 Steady State Transmission Planning Criteria below briefly describes the Transmission Planning steady state study methodology to meet TPL-001-4 Table 1 Contingency requirements:

Table 7 Steady State Transmission Planning Criteria (TPL-001-4 Table 1)

Category	Initial Condition	Event	Fault Type	Study Performed – The CAP addresses facilities that did not meet the appropriate criteria	
P0 No contingency	Normal System	None	N/A	Thermal and voltage analysis was performed on the SBAA System model assuming no additional outages other than those already modeled as described in the “Base Case Development” section (N-0).	
P1 Single Contingency	Normal System	Loss of one of the following:	3∅	PSS/E generator transformer branches were removed for each generator as part of N-1 contingency analysis. In some instances, more than one generator are removed in this analysis due to the outage associated with a common collector bus.	
		1. Generator			
		2. Transmission Circuit			Each PSS/E branch of the SBAA System model is removed from service one at a time. This has been compared to opening breaker to breaker and found to produce the same or more severe results for the SBAA System.
		3. Transformer			Each PSS/E transformer branch of the SBAA System model is removed from service one at a time.
		4. Shunt Device	Each PSS/E shunt device of the SBAA System is removed from service one at a time.		
5. Single Pole of a DC line	SLG	Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault	N/A	Each PSS/E branch circuit of the SBAA System model is removed from service one at a time.	
		2. Bus Section Fault	SLG	Manually defined contingencies on the SBAA System model that simulate a bus section fault are removed from service one at a time.	
		3. Internal Breaker Fault (non-Bus-tie Breaker)	SLG	Manually defined contingencies on the SBAA System model that simulate an internal breaker fault (non-bus-tie breaker) are removed from service one at a time.	
		4. Internal Breaker Fault (Bus-tie Breaker)	SLG	Manually defined contingencies on the SBAA System model that simulate an internal breaker fault (bus-tie breaker) are removed from service one at a time.	

Category	Initial Condition	Event	Fault Type	Study Performed – The CAP addresses facilities that did not meet the appropriate criteria
P3 Multiple Contingency	Loss of generator unit followed by System adjustments	Loss of one of the following:	3 \emptyset	
		1. Generator		A list of the two largest generators on the SBAA System model per kV level found at any one location is developed. From this list, a set of singular unit out cases is developed and then using these cases, each one of the remaining generators on the list is removed from service one at a time resulting in an N-G-G.
		2. Transmission Circuit		A set of singular unit out cases is developed from the SBAA System model. Using these cases, each branch segment is removed from service one at a time.
		3. Transformer		A set of singular unit out cases are developed from the SBAA System model. Using these cases, each branch segment that includes a transformer is removed from service one at a time.
		4. Shunt Device		A set of singular unit out cases is developed from the SBAA System model. Using these cases, each shunt device is removed from service one at a time.
		5. Single pole of a DC line	SLG	Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.
P4 Multiple Contingency (Fault plus stuck breaker)	Normal System	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following:	SLG	
		1. Generator		Manually defined contingencies that simulate the loss of multiple elements caused by a stuck breaker (non-bus-tie breaker) attempting to clear a Fault on a generator are removed from service one at a time.
		2. Transmission Circuit		Manually defined contingencies that simulate the loss of multiple elements caused by a stuck breaker (non-bus-tie breaker) attempting to clear a Fault on a transmission circuit are removed from service one at a time.
		3. Transformer		Manually defined contingencies that simulate the loss of multiple elements caused by a stuck breaker (non-bus-tie breaker) attempting to clear a Fault on a transformer are removed from service one at a time.
		4. Shunt Device		Manually defined contingencies that simulate the loss of multiple elements caused by a stuck breaker (non-bus-tie breaker) attempting to clear a Fault on a shunt device are removed from service one at a time. Only shunt devices expected to impact the BES are modeled as branch segments.
		5. Bus Section		Manually defined contingencies that simulate the loss of multiple elements caused by a stuck breaker (non-bus-tie breaker) attempting to clear a Fault on a bus section are removed from service one at a time.
		6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	Manually defined contingencies that simulate the loss of multiple elements caused by a stuck breaker (bus-tie breaker) attempting to clear a Fault on the associated bus are removed from service one at a time.

Category	Initial Condition	Event	Fault Type	Study Performed – The CAP addresses facilities that did not meet the appropriate criteria
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:	SLG	
		1. Generator		This contingency was not analyzed because a review by Southern Company Subject Matter Experts (SMEs) concluded that the most severe contingency would be a P5.5 since it would clear the entire bus. This contingency is expected to be very similar to the P5.5 contingency.
		2. Transmission Circuit		This contingency was not analyzed because a review by Southern Company SMEs concluded that the most severe contingency would be a P5.5 since it would clear the entire bus. This contingency is expected to be very similar to the P5.5 contingency.
		3. Transformer		This contingency was not analyzed because a review by Southern Company SMEs concluded that the most severe contingency would be a P5.5 since it would clear the entire bus. This contingency is expected to be very similar to the P5.5 contingency.
		4. Shunt Device		This contingency was not analyzed because a review by Southern Company SMEs concluded that the most severe contingency would be a P5.5 since it would clear the entire bus. This contingency is expected to be very similar to the P5.5 contingency.
		5. Bus Section		Simulations were run to determine which elements would open to clear the fault if a protection system failure occurred. This information was used to simulate the contingency in the steady state case.
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adjustments. 1. Transmission Circuit 2. Transformer 3. Shunt Device 4. Single pole of a DC line	Loss of one of the following:	3Ø	
		1. Transmission Circuit		PSSE is used to rank and remove from service combinations of elements based on the severity of the impact of the loss of these combinations on the SBAA portion of the planning model.
		2. Transformer		PSSE is used to rank and remove from service combinations of elements based on the severity of the impact of the loss of these combinations on the SBAA portion of the planning model.
		3. Shunt Device		PSSE is used to rank and remove from service combinations of elements based on the severity of the impact of the loss of these combinations on the SBAA portion of the planning model. Only shunt devices expected to impact the BES are modeled as branch segments.
		4. Single pole of a DC line	Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.	SLG

Category	Initial Condition	Event	Fault Type	Study Performed – The CAP addresses facilities that did not meet the appropriate criteria
P7 Multiple Contingency (Common Structure)	Normal System	The loss of:	SLG	
		1. Any two adjacent (vertically or horizontally) circuits on common structure 2. Loss of a bipolar DC line		Manually defined contingencies on the SBAA System model that simulate the loss of any two adjacent (vertically or horizontally) circuits on a common structure are removed from service one at a time. These contingencies were developed by SMEs to ensure that all are captured. Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.
Extreme Events	Normal System	Variable	Variable	Extreme events with significant potential impacts were reviewed and options to mitigate the impacts identified. Events evaluated included: 1. Planning events that were mitigated using specific System adjustments. However, it was assumed the adjustments did not occur. Studies were then performed to simulate the next fault with normal clearing before the System adjustments were made. 2. Local area events affecting the Transmission System, as defined by Subject Matter Experts, including: a. Loss of a tower line with three or more circuits. b. Loss of all Transmission lines on a common Right-of-Way. c. Loss of a switching station or substation (loss of the one voltage level plus transformers). d. Loss of all generating units at a generating station. 3. No wide area events affecting the SBAA System were identified.

Where Table 7 Steady State Transmission Planning Criteria required a generation outage as a portion of the contingency, a summary of key unit outs considered was developed and can be found in Section IV Steady State Project Details. This table shows not only the units considered but the cases in which they were used as well. Some unit outs were not needed in certain cases because the unit was already off due to the expected dispatch in the case. These selected generating units which provide more severe stress on the system have been identified through experience over many years of conducting power flow analysis based upon their relative size, location or other factors.

Steady State Sensitivity Analysis

The Standard requires additional Sensitivity Studies to be performed to demonstrate the impact of changes to the basic assumptions used in the base cases. The sensitivity selected was the availability of hydroelectric generation. This sensitivity was evaluated utilizing the criteria described in TPL-001-4 Table 1. The analysis was performed on all years of the Near-Term and Long-Term Planning Horizons using Off-Peak conditions with the availability of hydroelectric generation and on System Shoulder conditions, which represent 93% of System peak and the unavailability of hydroelectric generation. [Requirement 2 Part 2.1.4]

Steady State Equipment Sparing Analysis

The Transmission equipment sparing strategy is reviewed annually to identify Transmission equipment without a spare and has a replacement lead time greater than one year. Each piece of equipment was individually modeled as unavailable and evaluated for P0, P1, and P2 events using System peak, Off-Peak, and the sensitivity cases. [Requirement 2 Part 2.1.5]

Steady State Coordination with Adjacent Systems

In addition to contingencies on the GA ITS system, contingencies provided by neighboring systems in accordance with TPL-001-4 Requirement 3.4.1 are analyzed as a part of the annual study process. These neighboring systems are also monitored as part of all studies to determine if any contingencies on the ITS system have the potential to impact them. If potential impacts to neighboring systems are identified, the impacted neighbor is notified of those contingencies per the requirement.

B. Stability Analysis

Stability studies were conducted to consider P1 - P7 Planning Events and Extreme Events in the Near Term planning horizon. The simulations were made for System Peak Load conditions and for System Off-Peak load (approximately 50% of System peak load) conditions, for one of the five years in the Near Term planning horizon. The System peak cases included a dynamic Load model which represents the expected dynamic behavior of induction motor Load that could impact the study area. The light System load level of 50% of System peak load was chosen to be the lowest load level for which base load units are running at maximum output - a worst case for angular stability.

All projects resulting from Stability analysis to address any identified deficiencies have been added to the list of projects in Section IV Stability Project Details.

Table 8 Stability Transmission Planning Performance briefly describes the Transmission Planning stability study methodology to meet TPL-001-4 Table 1 performance requirements:

Table 8 Stability Transmission Planning Performance Requirements (TPL-001-4 Table 1)

Category	Initial Condition	Event	Fault Type	Study Performed – The CAP addresses facilities that did not meet the appropriate performance requirements
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3∅	A study was conducted which applied a normally-cleared, three-phase fault on every transmission line (P1.2) and transformer (P1.3) in the SBAA. Faults on generators (P1.1) will not be as severe because fault clearing will result in tripping a unit which is better for stability. Faults on shunt devices (P1.4) will also not be as severe because tripping a shunt device does not result in weakening the System as compared to tripping a transmission line or transformer. Thus, P1.1 and P1.4 were not explicitly studied.
		5. Single Pole of a DC line	SLG	Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault	N/A	Opening a line end without a fault will never cause a stability concern that has not already been identified by a category P1 event.
		2. Bus Section Fault	SLG	Planning events P2.2, P2.3, and P2.4 require single line to ground faults to be applied to bus sections or internal to breakers. These will always be less severe than a three-phase fault which will be covered by the extreme events specified in TPL-001-4 Table 1 Stability events 2.d and 2.e. When the three-phase faults in the extreme events result in instability, a solution will generally be included in the CAP. If situations should occur where the CAP is not used to address three-phase faults which resulted in instability, then the single line to ground fault will be investigated and appropriate corrective action included as needed.
		3. Internal Breaker Fault (non-Bus-tie Breaker)	SLG	
		4. Internal Breaker Fault (Bus-tie Breaker)	SLG	
P3 Multiple Contingency	Loss of generator unit followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device	3∅	The initial System condition of a generator being out of service is generally not a stability concern because less generation is better for transient stability. A generator out is only a potential stability concern for peak load levels in FIDVR prone areas and, therefore was studied only in FIDVR prone areas.
		5. Single pole of a DC line	SLG	Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.

Category	Initial Condition	Event	Fault Type	Study Performed – The CAP addresses facilities that did not meet the appropriate performance requirements
P4 Multiple Contingency (Fault plus stuck breaker)	Normal System	Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section	SLG	Planning events P4.1 through P4.6 require single line to ground faults to be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections with delayed clearing due to a stuck breaker. These will always be less severe than a three-phase fault which will be covered by Extreme Events specified in TPL-001-4 Table 1 Stability events 2.a through 2e. When a three-phase fault scenario considered in the extreme events result in instability, a solution will generally be included in the CAP. If a situation should occur where the CAP is not used to address three-phase faults which result in instability, then the single line to ground fault was investigated and the appropriate corrective action was included as needed.
		6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. Shunt Device 5. Bus Section	SLG	Planning events P5.1 through P5.5 require single-line-to-ground faults to be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections with delayed clearing due to a relay failure. Single line to ground faults will be less severe than a three-phase fault which will be covered by R4.5 extreme events specified in TPL-001-4 Table 1 Stability events 2.a through 2e. When the three-phase faults evaluated in the R4.5 extreme events resulted in instability, a solution was included in the CAP. In situations where the CAP was not used to address three-phase faults which resulted in instability, then the single line to ground fault was investigated and appropriate corrective action included as needed.
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adjustments. 1. Transmission Circuit 2. Transformer 3. Shunt Device 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer 3. Shunt Device	3Ø	Studies were performed with a Transmission element (P6.1 and P6.2) out of service at generating plants on the System. Then a three-phase, normally-cleared fault was studied on another element at the generating plant. If the generators are not stable for this contingency, then a System adjustment or a CAP project was implemented to make sure that the generation remained stable. Faults on shunt devices (P6.3) were not as severe because tripping a shunt device does not result in weakening the System as compared to tripping a transmission line or transformer. Thus, P6.3 was not explicitly studied.
		4. Single pole of a DC line	SLG	Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.

Category	Initial Condition	Event	Fault Type	Study Performed – The CAP addresses facilities that did not meet the appropriate performance requirements
<p>P7 Multiple Contingency (Common Structure)</p>	<p>Normal System</p>	<p>The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure</p>	<p>SLG</p>	<p>Single-line-to-ground faults will be simulated on two transmission lines at a generating plant that share a common tower for distances greater than one mile. The circuits to be studied were ones at generating plants which would have the most impact on stability.</p>
		<p>2. Loss of a bipolar DC line</p>		<p>Not applicable as HVDC lines are not currently utilized in the SBAA System and no HVDC lines outside of the SBAA have been identified by adjacent PCs and TPs as affecting the SBAA System in the planning horizon.</p>
<p>Extreme Events</p>				<p>Lists of contingencies which are expected to produce more severe System impacts for extreme events were created for evaluation in the stability studies. These events were divided into two categories:</p> <ol style="list-style-type: none"> 1. Planning events that were mitigated using specific System adjustments (resulting in temporary SOL's for Operations). Those adjustments should be assumed not to have occurred. Studies were made of the consequences of having the next three-phase fault with normal clearing before the System adjustments are made. 2. Three-phase faults with delayed clearing due to a stuck breaker or a relay failure. These contingencies were applied to generators, Transmission circuits, transformers, shunt devices, and bus sections at or near generating plants. These will have the most severe impact to the stability of the System.

Stability Past Studies

Past studies were utilized in some situations to demonstrate that performance requirements were met. For each category considered (i.e., P1 - P7 and Extreme Events), past studies were evaluated per requirements R2.6.1 and R2.6.2 of the Standard to ensure that they met the following criteria:

- Less than five years old unless a technical rationale supporting that the results of an older study are still valid;
- No material changes have occurred to the System represented in the study.

All past studies utilized in the assessment met the above criteria. [Requirement 2.6.1 and 2.6.2]

Stability Sensitivity Analysis (Near-Term Planning Horizon)

Requirement R2.4.3 of the Standard requires that additional sensitivity studies be performed to demonstrate the effects of various modeling assumptions used in the analysis. For the system stability studies completed, which used the standard base case, the following sensitivities were evaluated:

- For 50% System peak load cases, transfers to Florida were increased or local generation was increased to maximum output;
- For System peak load cases, the amount of induction motor load that was modeled with a dynamic load model was increased.

For the other studies, including past studies, a specific sensitivity was not evaluated. Those studies modified the output of the generator beyond the amount specified by the base dispatch (i.e., all generation in proximity to the study area was dispatched at full output whether the unit had firm service for full output or not). This study practice resulted in the most conservative results possible; thus, it was not necessary to study additional sensitivities. The sensitivity analysis revealed no new constraints. [Requirement 2.4.3]

Long-Term Stability Analysis

Stability studies were also conducted as needed in the Long-Term planning horizon to address the impact of material generation additions or changes in that time frame. Forecasted generation in the Long-Term transmission planning horizon that does not have firm service or has not been designated by an entity does not require a stability study. Only new generation for which a firm commitment to build has been made requires a unit specific stability study. [Requirement 2.5]

C. Short Circuit Analysis

The short circuit (breaker duty) assessment was performed by Southern Company Services Protection & Control Applications for the Near-Term planning horizon. The base case model used for this assessment included all existing facilities (transmission and generation) and planned facilities based on forecasted generation and future years' transmission expansion plan. The real and reactive Load forecasts and known commitments for Firm Transmission Service and Interchange were not represented in the models as they were not relevant to this assessment. The study methodology for short circuit analysis employs the Breaker Duty Module with the CAPE Short Circuit Analysis program to calculate margin between fault interrupting device capability and short circuit level at that location. The short circuit currents are at the highest with maximum generation online and with N-0 transmission contingency. Hence, no outages are considered in this assessment. [Requirement 2 Part 2.3]

The assessment is conducted annually for the Near-Term planning horizon to ensure that the fault interrupting devices can successfully interrupt the expected short circuit currents consistent with the Standard and *Guidelines for Short Circuit System Modeling and Short Circuit Assessment of The Southern Company Electric Transmission System*.

All projects resulting from that analysis to address any identified deficiencies have been added to the list of projects in Section IV Short Circuit Project Details. [Requirement 2 Parts 2.3, 2.6 and 2.8]

D. Interface Transfer Capability Assessments

The transfer capability assessments are used to identify transmission facilities that may potentially limit the ITS' ability to maintain its long-term firm obligations across the SBAA interfaces. Linear transfer analysis is performed to simulate an incremental transfer in addition to firm transactions already modeled in the powerflow cases. To reduce sensitivities to local generation dispatch issues, each transfer is simulated by scaling load uniformly in the participating areas. Transfer Distribution Factors (TDFs) are considered in evaluating potential limitations to transfers across each particular interface. In the identification of limiting facilities, known and applicable System Operating Limits ("SOLs") are respected. The assumptions, description of system models, summary of each interfaces transfer capability limitations and resulting projects are detailed in a report that is provided to Transmission Planning for inclusion of results into this document.

Pursuant to FAC-013-2, the interfaces of the SBAA are evaluated annually as part of the planning process. The analysis is done to ensure that the Southern Balancing Authority can maintain all long-term, firm transmission commitments and reliability reserve margins.

All projects resulting from that analysis to address any identified deficiencies have been added to the list of projects in Section IV Interface Transfer Capability Project Details.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

Northern Interface

For the Northern interfaces of MISO, TVA, Duke, SCPSA and SCEG, transferring power across one interface may mutually impact the ability to transfer power across other interfaces. Therefore, transfer capability assessments for the “northern” interfaces of the SBAA are evaluated in such a way as to ensure not only that there is sufficient transfer capability to accommodate all firm transactions across a particular interface, but also that there is sufficient transfer capability to accommodate all firm obligations simultaneously across all the “northern” interfaces. Furthermore, the assessments take into account potential “netting” impacts. If “netting” transfers (transfers of opposing flow) are allowed to remain in the assessment cases, potential problems may be masked in certain real-time situations when the transfers of opposing flow are not scheduled. Therefore, these opposing flow transfers may be removed to ensure that the most conservative screens are performed.

Florida Interface

The SBAA – FRCC interface consists of ties with four balancing authorities within FRCC: Florida Power and Light Company (FPL), DUKE Energy of Florida (DEF), Jacksonville Electric Authority (JEA), and the City of Tallahassee (TAL); collectively “Florida”. However, because the Florida interface is fundamentally radial from the SBAA and the transmission facilities in the connecting balancing authorities have a high-level of interdependence, the Florida interface is studied in a single Transfer Capability assessment. To ensure the most conservative screens are performed, impacts from “netting” are considered in the same manner as the Northern Interface.

The Georgia ITS peak and off-peak cases include Florida transfer level changes to review stresses on the Florida interface. These can be seen below:

Table 9 Georgia ITS - Florida Transfer Level Changes Modeled in Base Case

Year	Peak Case Transfer Amount (MW)
2018 – 2021	██████████
2022	██████████
2023 - 2028	██████████

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

IV. ANALYSIS RESULTS

A. Operating Guides

The use of operating guides is, in many cases, a viable alternative to making system improvements. In considering the use of an operating guide, operator action time as well as procedure complexity must be assessed when considering the overall effectiveness to correct the specific problem. If, for any reason, the use of an operating guide results in a violation of the aforementioned risk assessment factors, then the operating guide is not used.

Since risk and complexity are factors that the system operator will have to deal with when an operating guide is necessary, all operating guides that Transmission Planning identifies and tests are validated and approved by Georgia Power Transmission Operations Department. The only exception to this is if an operating guide is developed for use in the future after significant system upgrades have been made and Operations cannot replicate the projected system conditions. All operating guides are re-evaluated with each planning cycle to determine if they are still appropriate or should be replaced with a project, and if a project is more appropriate that there is sufficient time to get the project installed.

The following tables lists the thermal and voltage operating guides which were used in the development of the ten-year plan.

Table 10 Thermal and Voltage Operating Guides

Operating Guide Name	OG Start Date	OG End Date	Procedure
BLANKETS CREEK - WOODSTOCK 115 OPERATING GUIDE	6/1/2019	10/1/2023	[REDACTED]
CONYERS - CORNISH MOUNTAIN 115 OPERATING GUIDE	6/1/2019	10/1/2019	[REDACTED]
FIRST AVENUE - FULLER ROAD 115 KV OPERATING GUIDE	6/1/2019	10/1/2019	[REDACTED]
NORTH MARIETTA - SMYRNA 115 OPERATING GUIDE	6/1/2019	10/1/2024	[REDACTED]
SINCLAIR DAM - WARRENTON PRIMARY 115 OPERATING GUIDE	6/1/2019	1/1/2024	[REDACTED]
UNION POINT PRIMARY - MADISON PRIMARY 115 OPERATING GUIDE	1/1/2020	1/1/2022	[REDACTED]

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

B. Stability Project Details

The following group of projects are the result of the Stability studies conducted as needed in the Long-Term Planning Horizon to address the impact of material generation additions or changes for the TPL-001-4 Table 1.

The following information is included for each project:

- 1) project justification,
- 2) schedule for implementation (start date), and
- 3) expected required in-service date.

For transmission improvements, the start date is to provide necessary lead time to ensure the expected required in-service date can be met.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

NE GA HYDRO STABILITY (OUT OF STEP PROTECTION INSTALLATIONS)

TEAMS # 14922

Need Date 5/1/2019 Start Date 1/1/2014

Description

Provide system protection modifications to ensure that the Northeast GA hydro units and surrounding area comply with and support the system stability standards and guidelines.

The units identified in this study were Tallulah Falls, Terrora, Tugalo and Yonah. Install out of step protection as follows:

- Terrora: 2 units on a common GSU: 1 relay scheme required.
- Tallulah Falls: 6 units each with its own GSU: 6 relay schemes required.
- Tugalo: 4 units with 2 units on each GSU: 2 relay schemes required.
- Yonah: 3 units all on the same GSU: 1 relay scheme required.

Supporting Statement



Changes From Previous Ten Year Plan

No change

- Estimated Cost - GPC
- Estimated Cost - GTC
- Estimated Cost - MEAG
- Estimated Cost - DU
- Estimated Cost - ITS Assigned*

** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

VOGTLE PILOT PROTECTION SCHEME

TEAMS # 17790

Need Date 6/1/2020 Start Date 1/1/2019

Description

Add a second pilot protection scheme on the Augusta Corporate Park - Vogtle 230 kV line.

Supporting Statement

[Redacted content]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC

[Redacted]

Estimated Cost - GTC

[Redacted]

Estimated Cost - MEAG

[Redacted]

Estimated Cost - DU

[Redacted]

Estimated Cost - ITS

[Redacted]

Assigned*

[Redacted]

** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

WADLEY PRIMARY 500/230KV PROJECT (PHASE 2)

TEAMS # 14663

Need Date 6/1/2021 Start Date 6/1/2019

Description

Construct a 500kV ring bus. Install a 2016 MVA 500/230kV transformer with two LSB breakers, one to each 230 kV bus (MEAG# M1359001 or GTC).

GPC: Loop in the Vogtle - Warthen 500kV line into the new 500kV ring bus at Wadley Primary.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2019

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

C. Short Circuit Project Details

The following group of projects are the result of the Short Circuit analyses performed by the Southern company Services Protection and Control Department.

The following information is included for each project:

- 1) project justification,
- 2) schedule for implementation (start date), and
- 3) expected required in-service date.

For transmission improvements, the start date is to provide necessary lead time to ensure the expected required in-service date can be met.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

No Short Circuit Projects in Current 10 Year Plan

TEAMS # XXXXX

Need Date XX/XX/20XX

Start Date XX/XX/20XX

Description

Breaker duty study found no overstressed breakers at this time.

Supporting Statement

None.

Changes From Previous Ten Year Plan

No change

Estimated Cost – GPC	\$-
Estimated Cost – GTC	\$-
Estimated Cost – MEAG	\$-
Estimated Cost – DU	\$-
Estimated Cost – ITS Assigned*	\$-

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

D. Interface Transfer Capability Project Details

The following projects are the result of the Interface Transfer Capability Assessments analyses performed by the Southern Company Services Transmission Planning OATT Studies & Regional Planning Department.

The following information is included for each project:

- 1) project justification,
- 2) schedule for implementation (start date), and
- 3) expected required in-service date.

For transmission improvements, the start date is to provide necessary lead time to ensure the expected required in-service date can be met.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

AVALON JUNCTION - BIO 115 KV REBUILD

TEAMS # 17294

Need Date 6/1/2022 Start Date 6/1/2019

Description

Rebuild the Avalon Junction - Bio 115 kV line (20.5 miles of 636 ACSR/795ACSR) with 100° 1351 ACSR.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

No change

- Estimated Cost - GPC
- Estimated Cost - GTC
- Estimated Cost - MEAG
- Estimated Cost - DU
- Estimated Cost - ITS Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

E. Steady State Project Details

The following projects are the result of the Steady State analyses for the TPL-001-4 Table 1 Category P0, P1, and P2.3 EHV Planning Events in both the near-term and longer-term planning horizons for both peak and off-peak loading models.

The following information is included for each project:

- 1) project justification,
- 2) schedule for implementation (start date), and
- 3) expected required in-service date.

For transmission improvements, the start date is to provide necessary lead time to ensure the expected required in-service date can be met.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

ATHENA - EAST WATKINSVILLE 115KV RECONDUCTOR

TEAMS # 09603

Need Date 6/1/2021 Start Date 12/15/2019

Description

Reconductor 2.04 miles of 100°C 336 ACSR with 100°C 1033 ACSR on the White Hall to East Athens line segment. Replace the 600 A switches and the 750 AAC jumpers at the East Athens substation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC
 Estimated Cost - GTC
 Estimated Cost - MEAG
 Estimated Cost - DU
 Estimated Cost - ITS
 Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

BARNEYVILLE - DOUGLAS 115 KV UPGRADE (NV#1 - NV #2)

TEAMS # 11246

Need Date 6/1/2020 Start Date 6/1/2019

Description

Upgrade the Nashville #1 - Nashville #2 section (2.5 miles of 50 C-sagged 477.0 ACSR WHF line) for 100°C operation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2019

Estimated Cost - GPC

[Redacted]

Estimated Cost - GTC

[Redacted]

Estimated Cost - MEAG

[Redacted]

Estimated Cost - DU

[Redacted]

Estimated Cost - ITS Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

BLAKELY PRIMARY - MITCHELL 115KV LINE REBUILD

TEAMS # 15368

Need Date 9/1/2020 Start Date 3/1/2017

Description

Rebuild 26 miles of 50°C 266 ACSR with 100°C 795 ACSR from Blakely Primary to Greenhouse Road.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Scope change

Estimated Cost - GPC
Estimated Cost - GTC
Estimated Cost - MEAG
Estimated Cost - DU
Estimated Cost - ITS Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

BLANKETS CK.-WOODSTOCK 115-KV LN REBLD, (WOODSTK-LITTLE RVR)

TEAMS # 16278

Need Date 6/1/2024 Start Date 1/1/2023

Description

Rebuild the Woodstock – Little River 115 kV section, approximately 2.5 miles of 100°C 636 ACSR, using 100°C 1351 ACSR.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2023

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS Assigned*



* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

BRUNSWICK - ST SIMONS 115 KV LINE RECONDUCTOR

TEAMS # 12115

Need Date 6/1/2025 Start Date 1/1/2024

Description

Reconductor the Brunswick - Stonewall Street section to 100C 795 ACSR 2.7 miles (from existing 1.27 miles of 75C 477 ACSR and 1.35 miles of 100C 477 ACSR). Upgrade three Brunswick Switches to 1200 Amps (from existing 600 Amps).

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS Assigned*



* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

CENTER PRIMARY - WEYERHAEUSER 115KV CONDUCTOR UPGRADE

TEAMS # 16878

Need Date 3/1/2019 Start Date 9/10/2018

Description

Upgrade 5.5 miles of 50°C, 336 ACSR, 115 kV line to 60°C operation, from Neese to Colonial Pipe Line (Danielsville).

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

No change

Estimated Cost - GPC
Estimated Cost - GTC
Estimated Cost - MEAG
Estimated Cost - DU
Estimated Cost - ITS
Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

CLAXTON - STATESBORO PRIMARY 115 KV RECONDUCTOR

TEAMS # 13096

Need Date 6/1/2019 Start Date 9/1/2017

Description

GPC:

Reconductor the Claxton - Statesboro Primary 115 kV line (17.9 miles of 100°C 336 ACSR) with 100°C 1351 ACSR conductor. Work to be performed in 3 segments with staggered need dates:
 (1) Jimps Jct- Statesboro Primary (6/1/2017),
 (2) I16/Hwy301 - Jimps (6/1/2018), and
 (3) Claxton - I16/Hwy301 (6/1/2019).

At Claxton: Replace 1,200A breaker (052718) with 2,000A breaker and 600 amp switches (052717 & 052719) with 2,000 amp switches.

At Statesboro Primary: Replace 500 CU jumpers with 1590 AAC jumpers.

GTC:

At Langston Tap: Replace 1,200 amp switches (111961 & 111963) with 2,000 amp switches.

At Jimps Tap: Replace 1,200 amp switch (111983) with 2000 amp switch.

At Interstate 16/Highway 301: Replace 1,200 amp switches (907211 & 907233) with 2,000 amp switches

Supporting Statement



Changes From Previous Ten Year Plan

No change

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS



Assigned*

** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

DANIEL SIDING - LITTLE OGEECHEE 115-KV RECONDUCTOR

TEAMS # 11238

Need Date 6/1/2027 Start Date 1/1/2025

Description

Reconductor the Daniel Siding - Little Ogeechee 115kV line, approximately 10 miles, with 2-336 ACSS conductor (6.5 miles is in the ITS).

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

DEAL BRANCH - SYLVANIA 115-KV UPGRADE

TEAMS # 12095

Need Date 6/1/2023 Start Date 6/1/2020

Description

GPC: Upgrade the Deal Branch - Sylvania 115 kV line: Sylvania - King America - Dover Junction – Clito - Deal Branch sections (23.8 miles of 50°C 336 ACSR) with 100°C 336 ACSR. At King America Manufacturing, replace 2/0 CU jumpers with 1590 AAC.

MEAG: Replace 4/0 CU jumpers at Sylvania with 1590 AAC.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2020

Estimated Cost - GPC

[Redacted]

Estimated Cost - GTC

[Redacted]

Estimated Cost - MEAG

[Redacted]

Estimated Cost - DU

[Redacted]

Estimated Cost - ITS Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

DUM JON – FORT GORDON #2 115 KV NON-CONDUCTOR UPGRADES

TEAMS # 16307

Need Date 6/1/2028 Start Date 6/1/2027

Description

Replace two 600A switches (operating # 040141 and 040199) at Fort Gordon Hospital substation with 2000A switches. Replace the 300 copper jumpers and bus at Fort Gordon substation with 1590 AAC jumpers.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

EAST SOCIAL CIRCLE - STANTON SPRINGS 115 KV RECONDUCTOR

TEAMS # 17798

Need Date 5/1/2021 Start Date 1/1/2020

Description

Reconductor 6.2 miles of 100°C 636 ACSR Grosbeak with 100°C 1351. Replace 795 AAC Arbutus jumpers at Stanton Springs with 1590 AAC Coreopsis. Replace 1033 AAC Larkspur jumpers at East Social Circle with 1590 AAC Coreopsis.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

EVANS PRIMARY - THOMSON PRIMARY 115KV RECONDUCTOR

TEAMS # 13104

Need Date 6/1/2020 Start Date 6/1/2018

Description

Reconductor the Evans - Patriots Park section (4.23 miles of 100°C 336 ACSR) with 100°C 795 ACSR. Replace 336 ACSR jumpers with 795 ACSR at Patriots Park.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

No change

- Estimated Cost - GPC
- Estimated Cost - GTC
- Estimated Cost - MEAG
- Estimated Cost - DU
- Estimated Cost - ITS Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

FIRST AVENUE REPLACE LOWSIDE SWITCHES

TEAMS # 14814

Need Date 6/1/2026 Start Date 1/1/2025

Description

Replace the 1200A switch on the low side of Auto #4 with a 2000A switch or better.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

GOAT ROCK - RETIRE 115KV 60MVAR CAPACITOR BANK

TEAMS # 15518

Need Date 12/31/2019 Start Date 2/1/2019

Description

Retire the 115-kV 60 MVAR capacitor bank at Goat Rock.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

GORDON - N. DUBLIN (N. DUBLIN - EVERGRN CH) 115 KV UPGRADE

TEAMS # 11694

Need Date 6/1/2022 Start Date 1/1/2021

Description

Upgrade the North Dublin - Northwest Dublin - Evergreen Church sections, 7.94 miles of 50°C CU 4/0, for 75°C operation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

GORDON - SANDERSVILLE #1 115 KV LINE UPGRADE

TEAMS # 10442

Need Date 6/1/2022 Start Date 1/1/2020

Description

Upgrade the 30-mile, 50°C 336.4 ACSR, Gordon - Robins Spring section of the Gordon - Sandersville #1 115kV line for 100°C operation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2020

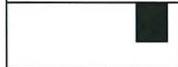
Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS Assigned*



* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

GRANITEVILLE - SOUTH AUGUSTA 115 & 230-KV TIE LINES

TEAMS # 16582

Need Date 6/1/2020 Start Date 4/1/2017

Description

Construct a new 5.2 mile, 230-kV tie-line, (GPC to SCE&G), from the South Augusta 230/115-kV substation to the South Carolina side of the Savannah River, using two conductors per phase bundled 1351 ACSR wire, sagged for 100°C operation.

Also, rebuild the existing South Augusta - Elanco 115-kV line from S. Augusta to the Nutrasweet Jct., (approximately 4.2 miles) and the former Urquhart tie-line, from the Nutrasweet Jct. to the South Carolina side of the Savannah River, (approximately 1.0 mile), for a total of 5.2 miles, using single 1351 ACSR conductor sagged for 100°C operation.

Build a new 5 terminal - 115 kV switching station near the abandoned DSM industrial area. The 115 kV line to be re-established with South Carolina will be out of this new switching station (Sand Bar Ferry SS).

Supporting Statement



Changes From Previous Ten Year Plan

No change

- Estimated Cost - GPC
- Estimated Cost - GTC
- Estimated Cost - MEAG
- Estimated Cost - DU
- Estimated Cost - ITS Assigned*

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

GTC: BLAKELY PRI - DAWSON PRI. 115KV LINE

TEAMS # 17573

Need Date 6/1/2020 Start Date 6/1/2018

Description

GTC will build five miles of new 115kV line from Greenhouse road to Cordrays Mill. GTC will rebuild its 46kV line from Cordrays Mill to Dawson Primary to 115kV operation. GPC will add a line terminal in the Dawson Primary substation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

GTC: BONAIRE PRIMARY 115 KV JUMPER REPLACEMENTS

TEAMS # 14567

Need Date 6/1/2024 Start Date 6/1/2023

Description

GTC: Replace 500 CU jumpers on the Robins AFB #3 115kV line at Bonaire Primary with 1590 AAC jumpers.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

GTC: TIGER CREEK 230 KV SERIES REACTORS

TEAMS # 15371

Need Date 6/1/2023 Start Date 2/1/2022

Description

GTC: Install 2% series reactors at Tiger Creek on the Branch Black and White 230 kv lines. These reactors will remain bypassed by switches until system contingencies require the bypasses to be opened.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2022 and scope change

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

JONESBORO - OHARA 230-KV RECONDUCTOR & UPGRADES

TEAMS # 10452

Need Date 6/1/2024 Start Date 6/1/2022

Description

Reconductor 6 miles of existing 1351 ACSR using 160°C 1351 ACSS. Replace the jumpers and bus with 2-1590 AAC at the Jonesboro substation. Replace the jumpers with 2-1590 AAC and line trap with a 2000A line trap at the O'Hara substation. The entire line is approximately 8 miles in length. Approximately 2 of the 8 miles have already been reconducted with 160°C 1351 ACSS.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2020

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

KETTLE CREEK - PINE GROVE 115KV LINE UPGRADE PHASE ONE

TEAMS # 15687

Need Date 6/1/2023 Start Date 6/1/2021

Description

Upgrade the Kettle Creek Primary to Pearson Tap portion of the line (20.5 miles of 50°C-sagged 4/0 ACSR) for 75°C operation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2020

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

KETTLE CREEK - PINE GROVE 115KV LINE UPGRADE PHASE TWO

TEAMS # 16589

Need Date 6/1/2028 Start Date 6/1/2026

Description

Upgrade the North Lakeland to Pearson Tap portion of the line (21.7 miles of 50°C-sagged 4/0 ACSR) for 75°C operation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

LAWRENCEVILLE - NORCROSS 230KV LINE RECONDUCTOR

TEAMS # 10129

Need Date 6/1/2022 Start Date 6/1/2020

Description

Reconductor 5.9 miles of 1033 ACSR conductor with 170°C 1351 ACSS conductor from Boggs Road to Lawrenceville. Replace 1590 AAC jumpers with 2-1590 AAC jumpers at Purcell Road.

Supporting Statement



Changes From Previous Ten Year Plan

Advanced From 2024

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS Assigned*



** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

LINE CREEK - FAIRBURN 2 115KV LINE UPGRADE

TEAMS # 17791

Need Date 6/1/2020 Start Date 6/1/2019

Description

Upgrade the 1.75 mile segment from Owens B J - Line Creek 50°C 336 ACSR line for 100°C operation.

Supporting Statement

[REDACTED]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS Assigned*



* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

LIVE OAK-STATESBORO PRI & LIVE OAK-WADLEY PRI 115KV UPGRADES

TEAMS # 13024

Need Date 6/1/2023 Start Date 1/1/2022

Description

Upgrade the Metter - Live Oak section of the Live Oak - Statesboro Primary 115kV line, 2.7 miles of 50°C 477 ACSR conductor, to 100°C. Also upgrade the Live Oak - Stillmore section of the Live Oak - Wadley Primary 115kV line, 5.94 miles of 50°C 477 ACSR, to 100°C. Replace switches and jumpers at Metter Primary. Replace bus, switches and jumpers at Metter.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2020

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

MCEVER ROAD - SHOAL CREEK 115KV REBUILD - PHASE 2

TEAMS # 10194

Need Date 6/1/2027 Start Date 1/1/2026

Description

Rebuild the 2-4/0 copper part (2.41 miles) of the McEver Road - College Square section of the McEver Road - Shoal Creek 115 kV line with 1033 ACSR for 100°C operation. The entire section is 3.7 miles.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

No change

- Estimated Cost - GPC
- Estimated Cost - GTC
- Estimated Cost - MEAG
- Estimated Cost - DU
- Estimated Cost - ITS Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

MCINTOSH 230/115-KV TRANSFORMER REPLACEMENT

TEAMS # 11662

Need Date 6/1/2019 Start Date 6/1/2018

Description

Replace the existing 280 MVA, 230/115 kV transformer with a 400 MVA transformer.

Supporting Statement

[Redacted supporting statement content]

Changes From Previous Ten Year Plan

No change

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



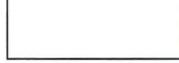
Estimated Cost - DU



Estimated Cost - ITS



Assigned*



* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

MEAG: AULTMAN ROAD - BONAIRE PRIMARY 115 KV RECONDUCTOR II

TEAMS # 13787

Need Date 6/1/2022 Start Date 3/1/2021

Description

MEAG: Reconductor the 1.99 miles, Sleepy Hollow - Peach Blossom 115 kV line section (presently 100°C 336 ACSR) of the Aultman Road - Bonaire 115kV line, with 100°C 795 ACSR.

GTC: Replace the jumpers at Sleepy Hollow with 1590 AAC.

Supporting Statement



Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC
 Estimated Cost - GTC
 Estimated Cost - MEAG
 Estimated Cost - DU
 Estimated Cost - ITS Assigned*



* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

MEAG: AULTMAN ROAD - FORT VALLEY #1 115 KV LINE UPGRADE

TEAMS # 15306

Need Date 6/1/2020 Start Date 6/1/2019

Description

MEAG: Upgrade the Aultman Road - Northrop Junction section (2.16 miles of 75°C-sagged 336.4 ACSR) of the Aultman Road - Fort Valley #1 115kV line for 100°C operation.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	
Estimated Cost - GTC	
Estimated Cost - MEAG	
Estimated Cost - DU	
Estimated Cost - ITS Assigned*	

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

MITCHELL 230KV REBUILD

TEAMS # 16528

Need Date 1/9/2019 Start Date 9/1/2016

Description

Rebuild of the Plant Mitchell switchyard to allow the spare autobank and the new autobank to both be in-service.

Supporting Statement



Changes From Previous Ten Year Plan

No change

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS Assigned*



* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

NORTH AMERICUS - PERRY 115 KV LINE REBUILD

TEAMS # 10391

Need Date 6/1/2020 Start Date 3/1/2015

Description

Reconductor/rebuild the North Americus - Perry 115 kV line, approximately 43 miles of 4/0 ACSR, with 100°C 795 ACSR.

Supporting Statement



Changes From Previous Ten Year Plan

No change

Estimated Cost - GPC



Estimated Cost - GTC



Estimated Cost - MEAG



Estimated Cost - DU



Estimated Cost - ITS Assigned*



** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

NORTH AMERICUS - PERRY 115 KV RELAYING AND NON-COND UPGRADES

TEAMS # 17244

Need Date 6/1/2020 Start Date 6/1/2017

Description

At Perry, add a transfer trip transmitter, tuner and wave trap to send status of breaker 48928 to Weyerhaeuser. At Montezuma, add a wave trap between the 115 kV bus and the capacitor banks. Replace the main bus and the jumpers with 1590 AAC.

GTC: At Weyerhaeuser, add a transfer trip receiver to receive status of breaker 48928 at Perry.

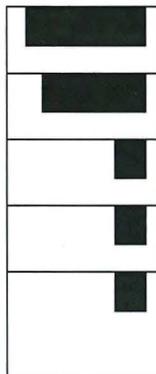
Supporting Statement



Changes From Previous Ten Year Plan

Delayed from 2018

Estimated Cost - GPC
Estimated Cost - GTC
Estimated Cost - MEAG
Estimated Cost - DU
Estimated Cost - ITS
Assigned*



** The ITS Assigned designation is for parity forecast purposes only.*

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

NORTH MARIETTA - SMYRNA (BLACK & WHITE) 115KV RECONDUCTORS

TEAMS # 13653

Need Date 6/1/2025 Start Date 1/1/2024

Description

Reconductor the North Marietta - Lockheed Martin Tap section of the North Marietta – Smyrna Black and White 115 kV lines, approximately 2.4 miles of 657 ACAR conductor, using conductor capable of at least 1200 amps.

Supporting Statement

[Redacted content]

Changes From Previous Ten Year Plan

Delayed from 2023

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

POSSUM BRANCH 230/115 KV PROJECT

TEAMS # 17678

Need Date 5/1/2022 Start Date 6/1/2019

Description

(GTC): Construct the 14-mile, Possum Branch – Roopville 230 kV Line with 100°C 1351 ACSR conductor. Install a 230/115 kV, 400 MVA transformer at Possum Branch with a 230-kV bus.
 (GPC): Construct a 230 kV a ring bus switching station at Roopville along with additional substation modifications.

Supporting Statement



Changes From Previous Ten Year Plan

New project

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

SINCLAIR DAM - WARRENTON 115KV RECONDUCTOR PHASE I

TEAMS # 15698

Need Date 6/1/2024 Start Date 6/1/2022

Description

Reconductor the Buffalo Road - Warrenton Primary section (17 miles of 50°C 4/0 CU) with 100°C 795 ACSR. Replace 90°C 4/0 CU jumpers with 1590 AAC at Buffalo Road.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Scope change to omit the Buffalo Road – South Devereux section

Estimated Cost - GPC	[Redacted]
Estimated Cost - GTC	[Redacted]
Estimated Cost - MEAG	[Redacted]
Estimated Cost - DU	[Redacted]
Estimated Cost - ITS Assigned*	[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

SINCLAIR DAM - WARRENTON 115KV RECONDUCTOR PHASE II

TEAMS # 17799

Need Date 6/1/2028 Start Date 1/1/2027

Description

Reconductor the Buffalo Road - South Devereux section (8.64 miles of 50°C CU 4/0) with 100°C 795 ACSR.

GTC: Replace the 90°C 4/0 copper bus and jumpers at South Devereux substation. Replace 600A line side switch # 038351 with a 1200A switch.

Supporting Statement

[Redacted]

Changes From Previous Ten Year Plan

Delayed from 2024

Estimated Cost - GPC

[Redacted]

Estimated Cost - GTC

[Redacted]

Estimated Cost - MEAG

[Redacted]

Estimated Cost - DU

[Redacted]

Estimated Cost - ITS Assigned*

[Redacted]

* The ITS Assigned designation is for parity forecast purposes only.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

F. Proxy Generation Details

The following projects are the result of the addition of Proxy Generation onto the ITS system.

The following information is included for each project:

- 1) project justification,
- 2) schedule for implementation (start date), and
- 3) expected required in-service date.

For transmission improvements, the start date is to provide necessary lead time to ensure the expected required in-service date can be met.

Proxy Generation is a mathematical method to solve the base cases models for future generation needs. These placeholder generators are generally selected at existing or former generation sites to minimize impacts on the system. Corrective Actions are identified but are not expected to become actual projects and are not included in the Summary of Georgia ITS Transmission Additions Table statistics.

CRITICAL ENERGY INFRASTRUCTURE INFORMATION

This data is confidential CEII and is subject to Regulation by CFR Sec. 388. 113. Any and all duplication of this data must contain this notification.

This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

V. ADDITIONAL SYSTEM ANALYSIS NOTES

There are several other studies done throughout the year that involve the Southern Company System as a whole. These studies are performed by the Transmission Planning – Bulk Transmission Group. The studies have the potential to require improvements to the Southern Company Transmission System. Some of these could be in the Georgia ITS. If System enhancements are pursued from these study results, then the impacts of the enhancements are included in the annual planning cycle.

A. Nuclear Final Safety Offsite Power Report (FSAR) Study

The FSAR analysis is a requirement of the NUC-001 Nuclear Plant Interface Coordination for Southern Nuclear Operating Company and Transmission Planning. For GPC, this analysis is performed annually for Plant Vogtle and Plant Hatch and the results are communicated to Southern Nuclear.

B. Designation Studies

A Designation Study is a study performed to identify the transmission system improvements needed to provide firm transmission capability for a resource designated to serve native load customers and wholesale network customers.

VI. APPENDIX

A. Validation Files / Reports

The transmission projects and operating guides listed were justified by data output from the report files listed below.

Table 11 PSSE Output Results

Version	File Location
v1C - STRE (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v1As_Stripped
v2C - VAL (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v2C
v3A - VAL (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v3A

Table 12 Thermal Problem Databases

Version	File Location
v1C - STRE (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v1As_Stripped\Problem Databases\2019-2028 TP-East Thermal Problems v1C STRE.mdb
v2C - VAL (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v2C\Problem Databases\2019-2028 TP-East Thermal Problems v2C (SHOTD).mdb
v3A - VAL (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v3A\Problem Databases\2019-2028 TP-East Thermal Problems v3A (SHOTD) - Dynamp.mdb

Table 13 Voltage Problem Databases

Version	File Location
v1C - STRE (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v1As_Stripped\Problem Databases\2019-2028 TP-East Voltage Problems v1C STRE.mdb
v2C - VAL (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v2C\Problem Databases\2019-2028 TP-East Voltage Problems v2C (SHOTD).mdb
v3A - VAL (2019-2028)	T:\TP-East\2018_TPE_Workplan\Screens\v3A\Problem Databases\2019-2028 TP-East Voltage Problems v3A (SHOTD).mdb

Table 14 Study Reports

Study Type	File Location
P-Events	T:\TP-Strategic\2018\18-001_TPL-001-4
Extreme Events	T:\TP-Strategic\2018\18-001_TPL-001-4\ExtremeEvents
Northern Interface	T:\TP-OATT_RegionalPlanning\Interface\2018\NIS
Nuclear FSAR - Hatch	T:\TP-Strategic\2018\18-013_Annual_Nuclear_FSAR\Hatch
Nuclear FSAR - Vogtle	T:\TP-Strategic\2018\18-013_Annual_Nuclear_FSAR\Vogtle
Stability Studies	T:\TP-Stab\Studies\2018\GPC
Designation Studies	T:\TP-Strategic\2018

B. Generation Assumptions

Basecase Definitions

Table 15 Basecase Definitions

Name	Abbr.	Load Level	Solar	Hydro
Summer Peak	S	Summer Peak	On	On
Shoulder	H	Shoulder (93%)	Off	Motor
Off-Peak	O	Off-Peak (70%)	On	Motor
Off-Peak w/ Hydro	J	Off-Peak (70%)	On	On
Daylight Shoulder	D	Shoulder (93%)	On	Motor
Hot Weather	T	Hot Weather (107%)	On	On

Generation in Cases

The following Table is **CONFIDENTIAL** - Not to be shared with any Marketing Function

Table 16 ITS Generation P_{max} in Cases

Plant Name	ITS	Fuel Type	PSSE Number	I&A Limit w/HS SS (MW)
ADDISON 1 (WEST GA) - GPC	GPC	PPA-CT		
ADDISON 3 (WEST GA) - GPC	GPC	PPA-CT		
ALBANY RENEWABLE ENERGY	GPC	Bio		
ASI CLASSIC 210 MW - US 1: RINCON SOLAR CENTER	GPC	PPA-Solar		
ASI CLASSIC 210 MW - US 2: BUTLER SOLAR FARM (FALL LN SLR)	GPC	PPA-Solar		
ASI CLASSIC 210 MW - US 2: OLD MIDVILLE RD LLC	GPC	PPA-Solar		
ASI PRIME 525 MW - US 1: BUTLER SOLAR	GPC	PPA-Solar		
ASI PRIME 525 MW - US 1: DECATUR PARKWAY SOLAR PROJECT	GPC	PPA-Solar		
ASI PRIME 525 MW - US 1: LS PAW-PAW	GPC	PPA-Solar		
ASI PRIME 525 MW - US 2: LIVE OAK SOLAR	GPC	PPA-Solar		
ASI PRIME 525 MW - US 2: WHITE OAK SOLAR	GPC	PPA-Solar		

Plant Name	ITS	Fuel Type	PSSE Number	I&A Limit w/HS SS (MW)
ASI PRIME 525 MW - US 2: WHITE PINE SOLAR	GPC	PPA-Solar		
BARTLETT'S FERRY 1 HY	GPC	Hydro		
BARTLETT'S FERRY 2 HY	GPC	Hydro		
BARTLETT'S FERRY 3 HY	GPC	Hydro		
BARTLETT'S FERRY 4 HY	GPC	Hydro		
BARTLETT'S FERRY 5 HY	GPC	Hydro		
BARTLETT'S FERRY 6 HY	GPC	Hydro		
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
BOULEVARD 1	GPC	CT		
BOWEN 1	GPC	Coal		
BOWEN 2	GPC	Coal		
BOWEN 3	GPC	Coal		
BOWEN 4	GPC	Coal		
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
DAHLBERG 10 - GPC	GPC	PPA-CT		
DAHLBERG 2 - GPC	GPC	PPA-CT		
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
DAHLBERG 4 - GPC	GPC	PPA-CT		
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
DAHLBERG 6 - GPC	GPC	PPA-CT		
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
DAHLBERG 8 - GPC	GPC	PPA-CT		
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
EXELON HEARD 1 (Tenaska GA)	GPC	PPA-CT		
EXELON HEARD 2 (Tenaska GA)	GPC	PPA-CT		
EXELON HEARD 3 (Tenaska GA)	GPC	PPA-CT		
EXELON HEARD 4 (Tenaska GA)	GPC	PPA-CT		
EXELON HEARD 5 (Tenaska GA)	GPC	PPA-CT		
EXELON HEARD 6 (Tenaska GA)	GPC	PPA-CT		

PUBLIC DISCLOSURE

Plant Name	ITS	Fuel Type	PSSE Number	I&A Limit w/HS SS (MW)
FLINT RIVER 1 HY	GPC	Hydro		
FLINT RIVER 2 HY	GPC	Hydro		
FLINT RIVER 3 HY	GPC	Hydro		
FORT BENNING SOLAR	GPC	Solar		
FORT GORDON SOLAR	GPC	Solar		
FORT STEWART SOLAR	GPC	Solar		
[REDACTED]				
[REDACTED]				
GASTON 1 GAS	GPC	Oil/Gas		
GASTON 2 GAS	GPC	Oil/Gas		
GASTON 3 GAS	GPC	Oil/Gas		
GASTON 4 GAS	GPC	Oil/Gas		
GASTON A	GPC	CT		
GEORGIA RENEWABLE POWER FRANKLIN LLC (GRP FRK BIO)	GPC	Bio		
GEORGIA RENEWABLE POWER MADISON	GPC	Bio		
GOAT ROCK 3 HY	GPC	Hydro		
GOAT ROCK 4 HY	GPC	Hydro		
GOAT ROCK 5 HY	GPC	Hydro		
GOAT ROCK 6 HY	GPC	Hydro		
GOAT ROCK 7 HY	GPC	Hydro		
GOAT ROCK 8 HY	GPC	Hydro		
GREEN POWER SOLUTIONS (DUBLIN BIOMASS)	GPC	Bio		
HAMMOND 1	GPC	Coal		
HAMMOND 2	GPC	Coal		
HAMMOND 3	GPC	Coal		
HAMMOND 4	GPC	Coal		
HARRIS 1 - GPC	GPC	PPA-CC		
HARRIS 2 - GPC	GPC	PPA-CC		
[REDACTED]				
[REDACTED]				
HATCH 1	GPC	Nuclear		
[REDACTED]				
[REDACTED]				
HATCH 2	GPC	Nuclear		
[REDACTED]				

Plant Name	ITS	Fuel Type	PSSE Number	I&A Limit w/HS SS (MW)
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
KING'S BAY SOLAR	GPC	Solar	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
LLOYD SHOALS 1 HY	GPC	Hydro	[REDACTED]	[REDACTED]
LLOYD SHOALS 2 HY	GPC	Hydro	[REDACTED]	[REDACTED]
LLOYD SHOALS 3 HY	GPC	Hydro	[REDACTED]	[REDACTED]
LLOYD SHOALS 4 HY	GPC	Hydro	[REDACTED]	[REDACTED]
LLOYD SHOALS 5 HY	GPC	Hydro	[REDACTED]	[REDACTED]
LLOYD SHOALS 6 HY	GPC	Hydro	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
MARINE CORPS LOGISTICS BASE (MCLB)	GPC	Solar	[REDACTED]	[REDACTED]
MAS GEORGIA LFG - PINE RIDGE	GPC	LFG	[REDACTED]	[REDACTED]
MAS GEORGIA LFG - RICHLAND CREEK	GPC	LFG	[REDACTED]	[REDACTED]
MCDONOUGH 4	GPC	CC	[REDACTED]	[REDACTED]
MCDONOUGH 5	GPC	CC	[REDACTED]	[REDACTED]
MCDONOUGH 6	GPC	CC	[REDACTED]	[REDACTED]
MCINTOSH 1	GPC	CT	[REDACTED]	[REDACTED]
MCINTOSH 1 COAL	GPC	Coal	[REDACTED]	[REDACTED]
MCINTOSH 10	GPC	CC	[REDACTED]	[REDACTED]
MCINTOSH 11	GPC	CC	[REDACTED]	[REDACTED]
MCINTOSH 2	GPC	CT	[REDACTED]	[REDACTED]
MCINTOSH 3	GPC	CT	[REDACTED]	[REDACTED]
MCINTOSH 4	GPC	CT	[REDACTED]	[REDACTED]
MCINTOSH 5	GPC	CT	[REDACTED]	[REDACTED]
MCINTOSH 6	GPC	CT	[REDACTED]	[REDACTED]
MCINTOSH 7	GPC	CT	[REDACTED]	[REDACTED]
MCINTOSH 8	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 3A	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 3B	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 3C	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 4A	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 4B	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 4C	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 4D	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 4E	GPC	CT	[REDACTED]	[REDACTED]
MCMANUS 4F	GPC	CT	[REDACTED]	[REDACTED]
MID GEORGIA COGEN	GPC	PPA-Cogen	[REDACTED]	[REDACTED]
MONROE POWER 1	GPC	PPA-CT	[REDACTED]	[REDACTED]
MONROE POWER 2	GPC	PPA-CT	[REDACTED]	[REDACTED]

Plant Name	ITS	Fuel Type	PSSE Number	I&A Limit w/HS SS (MW)
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
SIMON SOLAR FARM (SSFGEN)	GPC	PPA-Solar	[REDACTED]	[REDACTED]
SINCLAIR 1 HY	GPC	Hydro	[REDACTED]	[REDACTED]
SINCLAIR 2 HY	GPC	Hydro	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
SOLAR D&D CAMILLA	GPC	PPA-Solar	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
TALLULAH 1 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TALLULAH 2 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TALLULAH 3 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TALLULAH 4 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TALLULAH 5 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TALLULAH 6 HY	GPC	Hydro	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
TERRORA 1 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TERRORA 2 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TUGALO 1 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TUGALO 2 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TUGALO 3 HY	GPC	Hydro	[REDACTED]	[REDACTED]
TUGALO 4 HY	GPC	Hydro	[REDACTED]	[REDACTED]
VOGTLE 1	GPC	Nuclear	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]

PUBLIC DISCLOSURE

Plant Name	ITS	Fuel Type	PSSE Number	I&A Limit w/HS SS (MW)
VOGTLE 2	GPC	Nuclear		
VOGTLE 3	GPC	Nuclear		
VOGTLE 4	GPC	Nuclear		
WALLACE DAM 1 PS	GPC	Pump Storage		
WALLACE DAM 2 PS	GPC	Pump Storage		
WALLACE DAM 3 HY	GPC	Hydro		
WALLACE DAM 4 HY	GPC	Hydro		
WALLACE DAM 5 PS	GPC	Pump Storage		
WALLACE DAM 6 PS	GPC	Pump Storage		
WALTON COUNTY 1 (LGE MONROE)	GPC	PPA-CT		
WALTON COUNTY 2 (LGE MONROE)	GPC	PPA-CT		
WALTON COUNTY 3 (LGE MONROE)	GPC	PPA-CT		
WANSLEY 1	GPC	Coal		
WANSLEY 2	GPC	Coal		
WARNER ROBINS 1 (RAFB 1)	GPC	CT		
WARNER ROBINS 2 (RAFB 2)	GPC	CT		
WASHINGTON COUNTY (TIGER CREEK 2)	GPC	PPA-CT		
WASHINGTON COUNTY (TIGER CREEK 3)	GPC	PPA-CT		

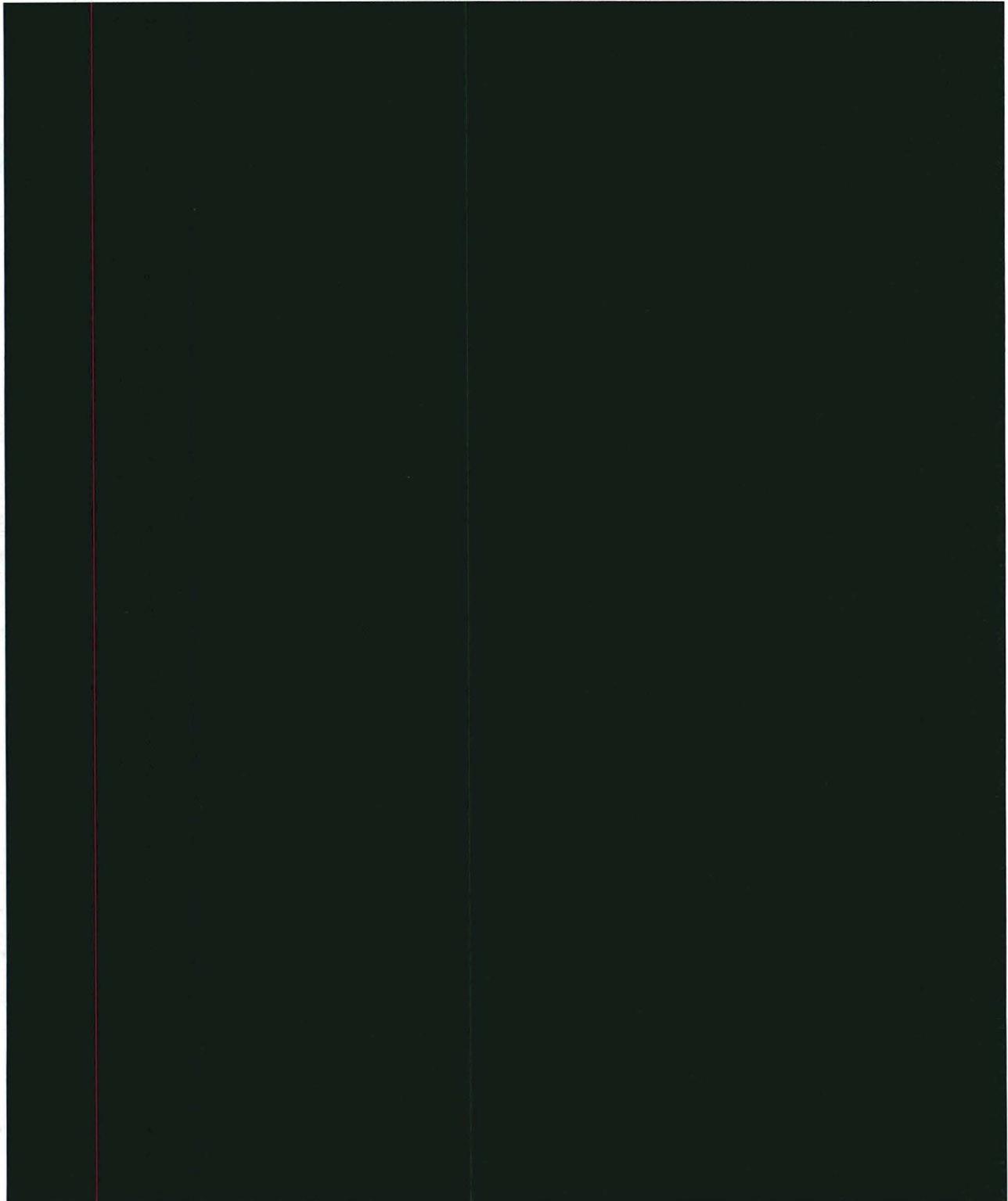
Plant Name	ITS	Fuel Type	PSSE Number	I&A Limit w/HS SS (MW)
WEYERHAEUSER INTERNATIONAL PAPER - FLINT RIVER	GPC	Bio		
WEYERHAEUSER INTERNATIONAL PAPER - PORT WENTWORTH	GPC	Bio		
WILSON 1A	GPC	CT		
WILSON 1B	GPC	CT		
WILSON 1C	GPC	CT		
WILSON 1D	GPC	CT		
WILSON 1E	GPC	CT		
WILSON 1F	GPC	CT		
YATES 6 GAS	GPC	Oil/Gas		
YATES 7 GAS	GPC	Oil/Gas		
YONAH 1 HY	GPC	Hydro		
YONAH 2 HY	GPC	Hydro		
YONAH 3 HY	GPC	Hydro		

FOOTNOTES:

1. VALUES FOUND IN TABLE MAY NOT REFLECT WHAT IS MODELED IN THE CASES. THE INFORMATION PROVIDED DOES NOT ALWAYS REFLECT OPERATIONAL LIMITS OR DESIGNATION AMOUNTS.

Generation Scenario (Unit Off) Cases

Table 17 Generation Scenario (Unit Off) By Case Type



Generation Code	Description	Summer Peak	Shoulder	Off-Peak

[D2]

ITS LOSS STUDY

2018 ITS LOSS STUDY
REPORT TO THE
TRANSMISSION PLANNING
WORK GROUP
September, 2018

Members of ITS Loss Study Working Group

Randy Cobb
David Majors
Jeremy Talley
Ken Wofford
James Harper

Georgia Power Company
Municipal Electric Authority of Georgia
Dalton Utilities
Georgia Transmission Corporation
Georgia Transmission Corporation

ITS LOSS STUDY REPORT

TABLE OF CONTENTS

	Page
I. EXECUTIVE SUMMARY	1
A. INTRODUCTION	1
B. METHODOLOGY	1
C. RESULTS	1
D. CONCLUSIONS.....	3
E. RECOMMENDATIONS.....	3
F. EXHIBIT 1 (2018 ITS DEMAND LOSSES).....	6
G. EXHIBIT 2 (2018 ITS ENERGY LOSSES).....	7
II. Introduction.....	8
A. Work Plan	8
B. Outline of Report	8
III. Electrical Losses at the “A” Level.....	9
A. Generator Step-up Transformer Loss.....	9
IV. Electrical Losses at the A to D Levels.....	9
A. Bulk Transmission Losses (B).....	9
B. 230/XX and 115/XX Transformer Loss (T)	10
C. Station Service Loss (SS).....	11
D. Subtransmission Line Loss and 69/XX and 46/XX Transformer Loss (S)	11
V. Other Components of Loss	11
A. Capacitor and Reactor Loss	12
B. Catenary/Equivalencing in Load Flow Loss.....	12
C. Contact Resistance Loss	12
D. Corona Loss	13
E. Deviation from Base Case Schedules Loss.....	13
F. Deviation in Inadvertent Interchange Loss	13
G. E/M Fields Loss	14
H. Harmonic Distortion Loss.....	14
I. Insulator Leakage Loss	14
J. Line Out Operation Loss.....	15
K. Overhead Ground Wire (OHGW) Loss	15
L. Power Factor Loss.....	15
M. Temperature Compensation of Test Resistances Loss.....	16
N. Unbalanced system Operation Loss.....	16
O. Unmetered Auxiliary Equipment.....	16
VI. APPENDIX.....	18
VII. APPROVAL PAGE.....	22

ITS LOSS STUDY REPORT

I. EXECUTIVE SUMMARY

INTRODUCTION

The ITS Loss Study Working Group has completed an analysis of estimated losses on the Integrated Transmission System for calendar year 2018. This study used ITS loss studies performed in 2014, 2008, 2002 and 1987 which included estimates of peripheral components contributing to overall system losses that have not been reflected in typical load flow computer program analysis.

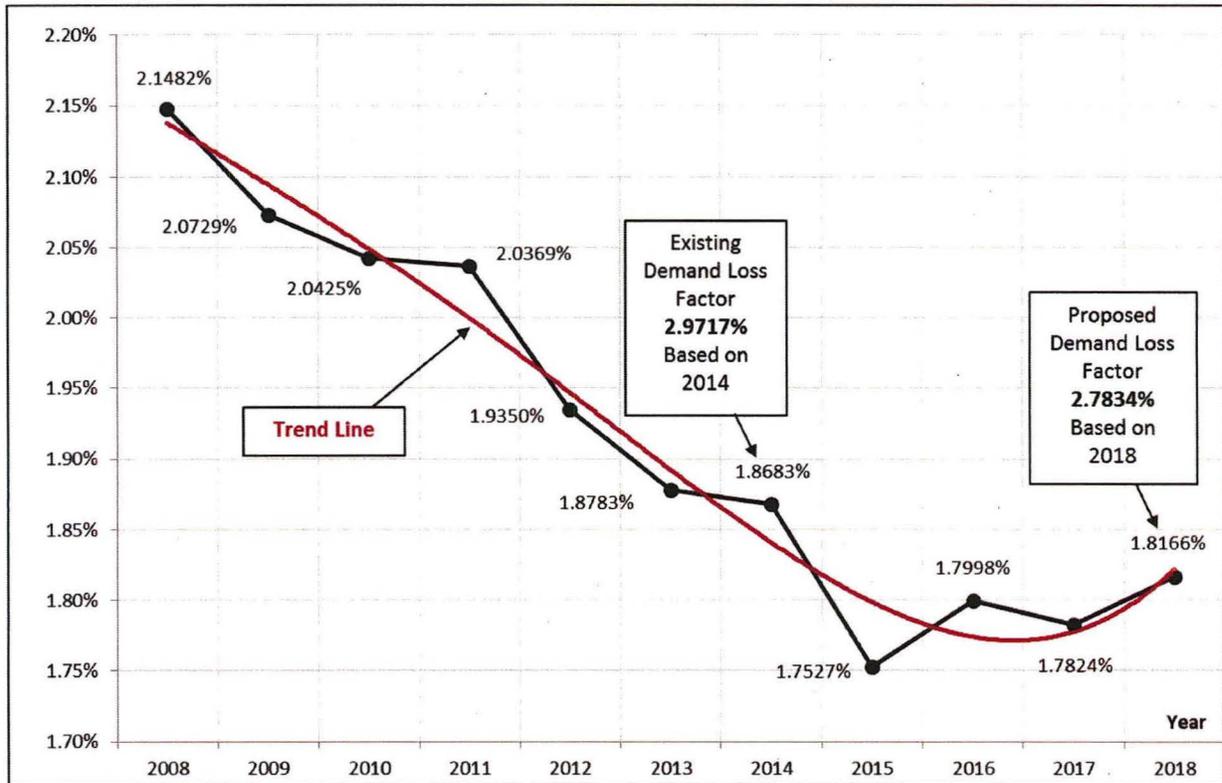
METHODOLOGY

This study was conducted in two stages. The first stage consisted of modeling the transmission system (115 kV and above) as well as determining values to be used for estimating bulk transmission losses, losses in 230/xx and 115/xx transformers, losses resulting from serving station service loads, and losses on the subtransmission system (46 kV and 69 kV). These estimated losses were computed from load flow results for both peak demand and average energy, using peak hour cases for six different day types: Summer weekday & weekend, Winter weekday & weekend and Spring/Fall weekday & weekend. The peak demand loss factor is based on a composite of 16 load flow cases and the average energy loss factor is based on a composite of 4608 load flow cases.

The second stage of the study addressed 15 components which the working group felt could be contributing to system losses but which would not be reflected in traditional load flow modeling. This analysis involved recalculating the loss values of the 15 components based on 2018 data.

The resulting loss factors are based on the v1As18 ITS base cases. (See Figure 1: Base Case Loss Trend).

Figure 1: Base Case Demand Loss Trend



Note: The ITS demand loss factor for 2006 through 2014 was 3.2586%, for 1995 through 2005 was 3.8060%, and before that was 4.1276%.

These data points are the average ITS demand losses on the bulk system from the base cases. For example, the 1.8166% in 2018 in the chart is the average ITS demand losses from the S18vxxs18.sav cases. The demand loss factor, e.g., 2.7834% in 2018 is the total transmission demand losses, as shown in Exhibit 1.

RESULTS

Summaries of the numerical results of these studies are included as Exhibits 1 and 2. Based on this study, total demand loss on ITS transmission system is 2.7834% of the total system load, while total energy loss is 2.4661% of the average load. Figures 2 and 3 illustrate the service level designation and the system power flow orientation.

The majority of both demand and energy losses come from bulk transmission, transmission substations, station service transformers and subtransmission. These losses are 2.6323% for demand and 2.1759% for energy, which account for approximately 94.6% and 88.2% of total demand and energy losses respectively, which was the expected result.

Losses due to the other components on the system, such as capacitors and reactors, catenary, contact resistances, corona, deviation from base case schedules, deviation in inadvertent interchange (loop flows), electro-magnetic fields, harmonics, insulator leakage, line out operation, overhead ground wire losses, power factor, temperature compensation resistance, unbalanced system operation and unmetered auxiliary equipment were calculated for both demand and energy by using recent data for the ITS system and applying the appropriate formulas identified in and since the 1987 study. Demand losses for these components account for 0.1511% of total load, while energy losses account for 0.2902% of the average load.

In summary, peak demand and average energy losses are in similar range as in previous years. As expected, the highest percentage loss on the bulk transmission system should occur during peak load conditions. However, the largest percentage losses on a number of other components occur during lower load levels due to the no-load components of transformers, adverse weather conditions affecting corona losses, etc.

CONCLUSIONS

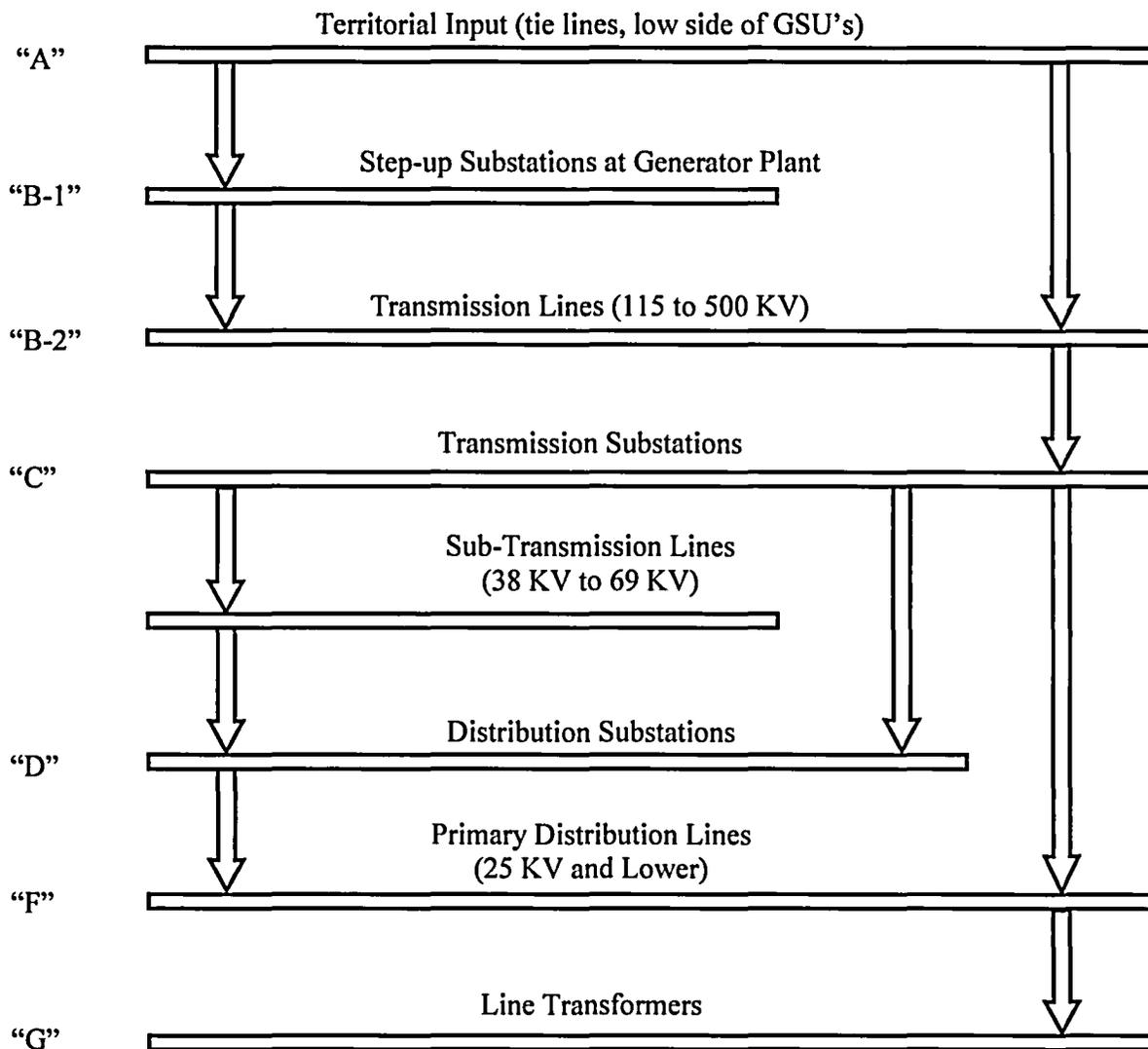
Because of the consistency in results of this study with prior studies and consistency between demand and energy losses, the Working Group concluded that the loss factors shown on the attached summary sheets are the most accurate information available at this time. Further, as major changes planned in the transmission system and major changes expected in patterns of load and generation on the integrated system occur, these numbers should be updated.

RECOMMENDATIONS

1. Recognize the attached 'loss factors' as the most accurate available at this time.
2. Continue to track the losses in the contract cases where the model year equals the series year for each version of each series of cases. Calculate the three-year rolling average.
3. Update the study every 3 years or when the three-year rolling average of the loss factor changes from that in the latest approved, in-use ITS loss factor by 0.1%.

**Figure 2: Service Level Designation
And
Power Flow Diagram**

Service Level



Indicates direction of power flow



Figure 3: Service Level Designation and Power Flow Diagram

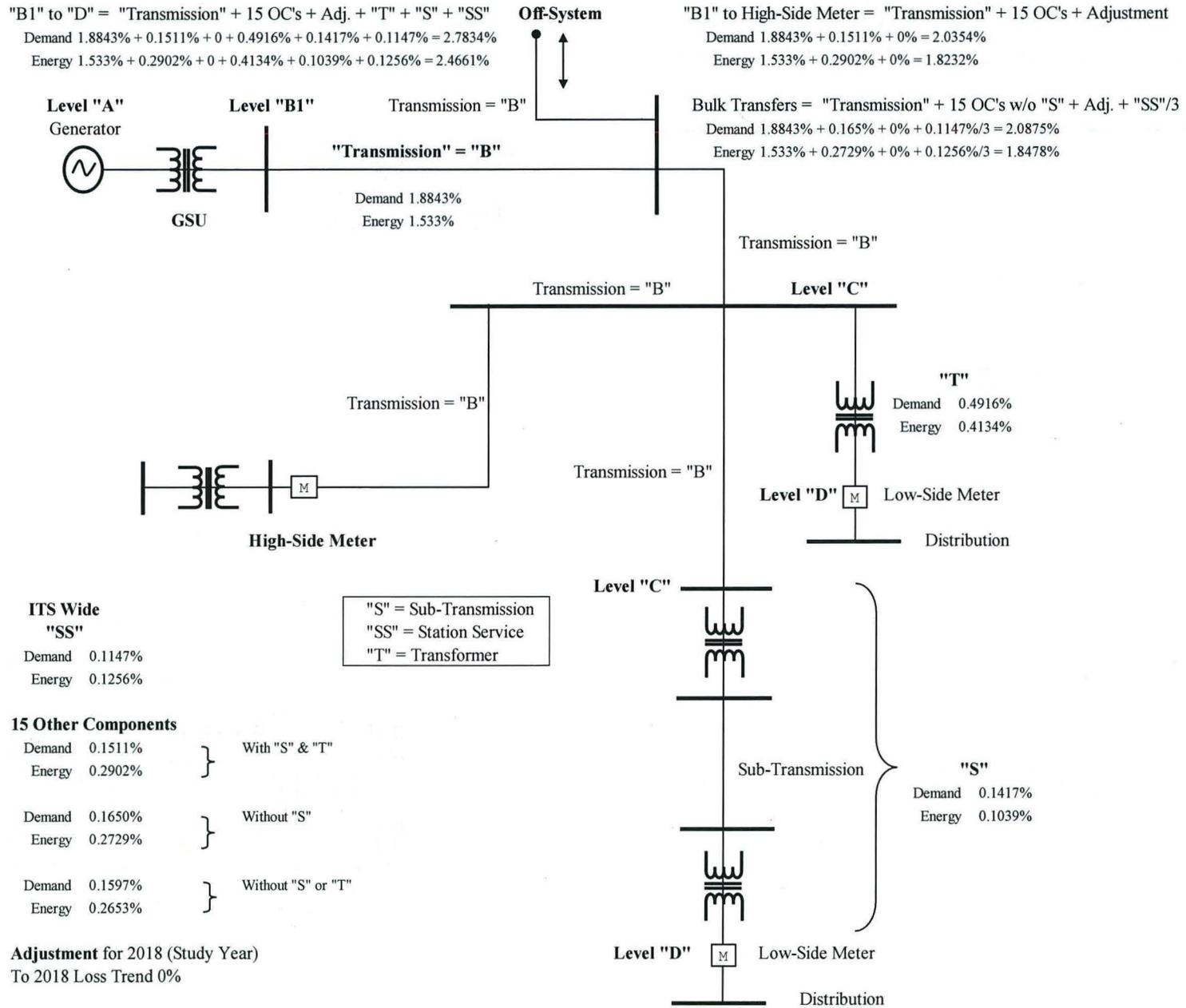


EXHIBIT 1

2018 ITS DEMAND LOSSES

B1 TO D MAJOR COMPONENTS		2018	2014	Delta	
		%	%	%	
Bulk Transmission	B	1.8843	1.8750	0.0093	(1, 3)
230/xx and 115/xx Transformers	T	0.4916	0.5929	-0.1013	(3)
Station Service	SS	0.1147	0.1202	-0.0055	
Subtransmission (69kV and 46 kV)	S	0.1417	0.2087	-0.0670	(1)
Subtotal:		2.6323	2.7968	-0.1645	
OTHER COMPONENTS		2018	2014	Delta	
		%	%	%	
Capacitors and Reactors		0.0037	0.0046	-0.0009	
Catenary Adjustment		0.0405	0.0417	-0.0012	
Contact Resistances		0.0001	0.0001	0.0000	
Corona		0.0192	0.0181	0.0011	
Deviation From Base Case Schedules		0.0000	0.0000	0.0000	
Deviation in Inadvertent Interchange		0.0277	0.0277	0.0000	
E/M Fields		0.0057	0.0056	0.0001	
Harmonics		0.0017	0.0019	-0.0002	
Insulator Leakage		0.0197	0.0189	0.0008	
Line-Out Operation Adjustment		0.0041	0.0044	-0.0003	
OHGW		0.0284	0.0292	-0.0008	
Power Factor Adjustment		-0.0273	-0.0065	-0.0208	(2)
Temperature Compensation of Resistance		0.0000	0.0000	0.0000	
Unbalanced System Operation		0.0252	0.0268	-0.0016	
Unmetered Auxiliary Equipment		0.0024	0.0024	0.0000	
Subtotal:		0.1511	0.1749	-0.0238	
Total Demand Losses		2.7834	2.9717	-0.1883	
Adjustment For Trend in Base Case Losses		0.0000	0.0000	0.0000	
TOTAL TRANSMISSION DEMAND LOSSES (%)		2.7834	2.9717	-0.1883	

- (1) System Topology changes
(2) Updated input data
(3) No-load loss calculation update

	2018	2014	Delta
Peak Demand =	26,716	26,885	-168 MW
Energy Use =	131,164,074	134,716,967	-3,552,893 GWh
Load Factor =	56.05%	57.20%	-1.15%

EXHIBIT 2

2018 ITS ENERGY LOSSES

B1 TO D MAJOR COMPONENTS		2018	2006	Delta	
		%	%	%	
Bulk Transmission	B	1.5330	1.7480	-0.2150	(1, 3)
230/xx and 115/xx Transformers	T	0.4134	0.6878	-0.2744	(3)
Station Service	SS	0.1256	0.0685	0.0571	(2)
Subtransmission (69kV and 46 kV)	S	0.1039	0.1394	-0.0355	(1)
Subtotal:		2.1759	2.6437	-0.4678	
OTHER COMPONENTS		2018	2006	Delta	
		%	%	%	
Capacitors and Reactors		0.0010	0.0043	-0.0033	
Catenary Adjustment		0.0327	0.0377	-0.0050	
Contact Resistances		0.0001	0.0001	0.0000	
Corona		0.0883	0.0767	0.0116	
Deviation From Base Case Schedules		0.0000	0.0000	0.0000	
Deviation in Inadvertent Interchange		0.0500	0.0475	0.0025	
E/M Fields		0.0143	0.0137	0.0006	
Harmonics		0.0014	0.0016	-0.0002	
Insulator Leakage		0.0352	0.0459	-0.0107	
Line-Out Operation Adjustment		0.0018	0.0070	-0.0052	
OHGW		0.0229	0.0264	-0.0035	
Power Factor Adjustment		0.0023	0.0030	-0.0007	
Temperature Compensation of Resistance		0.0000	0.0001	-0.0001	
Unbalanced System Operation		0.0359	0.0451	-0.0092	
Unmetered Auxiliary Equipment		0.0043	0.0053	-0.0010	
Subtotal:		0.2902	0.3144	-0.0242	
Total Energy Losses		2.4661	2.9581	-0.4920	
Adjustment For Trend in Base Case Losses		0.0000	-0.0500	0.0500	
TOTAL TRANSMISSION ENERGY LOSSES (%)		2.4661	2.9081	-0.4420	

- (1) System Topology changes
- (2) Updated input data
- (3) No-load loss calculation update

	2018	2006	Delta
Peak Demand =	26,716	24,455	2,261 MW
Energy Use =	131,164,074	124,914,783	6,249,291 GWh
Load Factor =	56.05%	58.31%	-2.26%

ITS LOSS STUDY REPORT

II. Introduction

This report is the most recent in a series of studies directed at determining losses on the Integrated Transmission System. The primary purpose of these studies has been to determine loss factors to be used in adjusting metered loads at delivery points to a common reference point (B1). These factors are currently used by the ITS participants for allocation of transmission investment responsibility and are made available to other parties for use as appropriate. In this study, 15 peripheral components, which contribute to overall system losses but are not reflected in load flow computer programs, were computed to more accurately reflect the total system losses.

Work Plan

This study was conducted in two stages. The first stage consisted of modeling the transmission system (115 kV and above) as well as determining values to be used for estimating bulk transmission losses, losses in 230/xx and 115/xx transformers, losses resulting from serving station service loads, and losses on the subtransmission system (46 kV and 69 kV). These estimated losses were computed from load flow results for both peak demand and average energy, using peak hour cases for six different day types: Summer weekday & weekend, Winter weekday & weekend and Spring/Fall weekday & weekend. The peak demand loss factor is based on a composite of 16 load flow cases and the average energy loss factor is based on a composite of 4608 load flow cases.

The second stage of the study addresses 15 components as specified in ITS Planning Procedure No. 21, ITS Loss Study Methodology. This analysis involved recalculating the loss values of the 15 components based on recent data.

Outline of Report

The following section includes a brief summary of the methodology and results of each of the approximately 20 factors which have been analyzed as contributing to overall system losses. The next section of the report contains the conclusions and recommendations with regard to the results of this study as well as suggestions for further study. In addition, a limited number of extensive appendices have been prepared which contain the detailed work papers, relevant source documents and other references used in the analysis.

III. Electrical Losses at the “A” Level

Generator Step-up Transformer Loss

For the purposes of this study, we have modeled the system so that all GSU’s included in ITS system were assigned to a separate zone (we chose Zone 251 in this case). These GSU losses are not included in the loss factors shown in Exhibits 1 and 2.

The demand step-up losses (service level A-B1) on GSU’s were 53.07 MW or 0.1965% of the ITS connected generation, which was 27,006.1 MW.

Note that the denominator here (MW at the low side of the GSU) is different from the denominator used in other parts of this study (load + losses, or equivalently the sum of inputs to the ITS network from the high side of GSU’s and from tie lines at the ITS border). Therefore, the loss percentages are not directly additive. If A-B1 losses are 0.1965% and B1-D losses are 2.7834%, then the proper calculation for A-D losses is:

$$1 - ((1 - 0.001965) \times (1 - 0.027834)) = 2.9744\%, \text{ not } 0.001965 + .027834 = 2.9799\%.$$

The annual energy losses on GSU’s were 282,134 MWh or 0.2316% of the annual ITS generation, which was 121,796,193 MWh.

IV. Electrical Losses at the B1 to D Levels Bulk

A. Transmission Losses (B)

Load Flow

The primary purpose of the utility load flow computer program is to simulate the behavior of the power system in terms of line loadings and bus voltages for a given set of input conditions. The load flow program models steady state performance; that is, the load flow solution of the given set of input conditions assumes that the system is free to operate in this mode until the input is changed. One of the many features of the utility load flow program is its ability to calculate “I squared R” losses for a designated system representation. Accordingly, the bulk transmission (115 kV, 230 kV and 500 kV) network system estimated losses were calculated using the load flow computer program.

Even though the aggregate Georgia load and territorial supply can be forecasted with reasonable accuracy, individual substation loads and individual generator outputs cannot be predicted with the same confidence. Fortunately, all of the individual loads are distributed throughout the state and each particular load is small with respect to the total aggregate Georgia load. As a result the ability to forecast each load accurately does not greatly impact the ability to estimate “I squared R” losses for the Georgia ITS. The generation, however, is aggregated and in terms of megawatts (with respect to the Georgia Territorial Supply) some of the plants are sizable. As a result, the generation dispatch does significantly affect losses. A probabilistic generation dispatch approach

was utilized so as to not have a disproportionate effect of any one particular dispatch on transmission losses.

Load Flow Cases

This study was performed on the Southern Electric System transmission planning 2018 series, version 1A Summer, Winter, and Fall Peak power flow cases representing 2018 expected conditions. The peak demand loss factor is based on a composite of the no-unit-off base case and the 15 most probable single-unit and double-unit out load flow cases. The average energy loss analysis was based on a composite of the no-unit-off base case and the 30 most probable single-unit and double-unit out load flow cases, each modeled at 144 different load levels representing hourly cases for six different day types: Summer weekday & weekend, Winter weekday & weekend and Spring/Fall weekday & weekend. A total of 4608 cases were used to develop the energy loss factor. The unit-out probability analysis was based on data obtained from SCS Resource Planning Department. Using the forced outage rates of the largest units in the state of Georgia and other large units in the Southern Electric System's Bulk Power pool, the probability that one large unit at each plant was forced off-line was calculated for each case. Sibling unit outages were considered as identical conditions and smaller units were considered always available. See Tables 1 and 2 in the Appendix for the lists of Unit-out probabilities.

Tools used in this analysis were Siemens Power Technologies International PSS[®]E power flow software and the SCS-developed economic dispatch program. This process captured the megawatt losses on the ITS as modeled from the high-side of the generator step-up transformers, to the high-side of the distribution transformers.

The recommended units were taken off-line and then the Southern System was economically re-dispatched. For the energy cases, Area 1 load was scaled and a typical hydro schedule applied before the re-dispatch (see Table 3 in the Appendix for the hydro schedules used, and Table 4 for the load shapes of each day type). For each case, ITS losses were then captured, and the resultant Bulk Transmission percentage loss was calculated as the weighted average megawatt loss divided by the sum of the peak megawatt load plus the weighted average megawatt loss (see Table 5 in the Appendix). The ITS Loss Study Working Group found that the value of loss attributable to the Bulk Transmission system, excluding GSU transformers, to be 1.8843% for Demand Loss and 1.5330% for Energy Loss. These values include "no load" losses for the transformers with low-side voltages of 115 kV and above. "No load" losses are not represented in the power flow model, and are taken from manufacturer test reports and approximations.

B. 230/XX and 115/XX Transformer Loss (T)

The same process that was utilized in the load flow portion of the study was used to calculate losses for the 230/XX and 115/XX transformers. Estimated losses were computed by calculating the I²R losses through the transformer banks for the 144 time periods for both peak demand and average energy, using hourly cases for six different day types: Summer weekday & weekend, Winter weekday & weekend and Spring/Fall weekday & weekend. The transformer loading was adjusted according to the load shape developed for use in the bulk transmission loss calculation.

Existing computer files, used by the load forecast program, containing relevant substation transformer information, are updated annually by the ITS planners to obtain an accurate model. The base case update is accomplished in two steps. First, actual metered demands for each substation, at the time of the system peak hour, are loaded to the files. The second step involves the manual update of all transformer-related data, such as transformer rating, impedance and core loss. The “no load” transformer losses were approximated by counting the total number of banks and applying a generic approximation derived from a sample of test reports with typical results. This generic approximation value was determined to be 27.5 kW per transformer.

The ITS Loss Study Working Group found that the value of loss attributable to 230/XX and 115/XX transformers to be 0.4916% for Demand Loss and 0.4134% for Energy Loss.

C. Station Service Transformer Loss (SS)

This study views all station service energy (such as lighting, control house air conditioning, meters, clocks, heaters, pumps and fans) as loss and estimates an energy and demand loss component for station service.

There are 3 types of station service transformers, based on the voltage levels:

1. Station service transformers in 500/230 kV substations
2. Station service transformers in 230/115 kV substations
3. Station service transformers in 230/xx and 115/xx substations

The load connected to these station service transformers was estimated based on the anticipated utilization throughout the year. Based on the analysis, the ITS Loss Study Working Group estimated the value of loss attributable to station service energy as 0.1147% for Demand Loss and 0.1256% for Energy Loss.

D. Subtransmission Line Loss and XX/69 and XX/46 Transformer Loss (S)

The same process that was utilized in the load flow portion of the study was used to calculate losses for the subtransmission line loss and XX/69 and XX/46 transformers. Estimated subtransmission Demand Losses were captured by dispatching the 2008 peak case for the 144 time periods: Summer weekday & weekend, Winter weekday & weekend and Spring/Fall weekday & weekend. The losses for the time periods were then annualized to estimate the energy losses.

The values for the demand and energy losses on the subtransmission system were updated using the 2018 subtransmission case data, based on the process and information obtained from the 2008 subtransmission loss study done by the area planning departments. The loss values attributable to Subtransmission Line Losses and XX/69 and XX/46 Transformer Losses are 0.1417% for Demand Loss and 0.1039% for Energy Loss.

V. Other Components and Adjustments

A. Capacitor and Reactor Loss

Losses attributable to capacitors and reactors are those electrical losses resulting from the operation of shunt capacitors and shunt reactors. These devices are represented in the power flow simulation as ideal devices (no power consumption) supplying or consuming reactive power. Capacitors consume power in proportion to their reactive output, and their control circuitry also consumes power. Reactors are electrically similar to transformers, and in that respect, their power consumption is analogous to the transformer “No Load” losses. As in capacitors, the control circuitry of reactors also consumes power.

Based on the nameplate data, losses in capacitors are estimated to be 0.15 W/kVA or 0.015%. In 2018, at peak, the capacitive reactive power was 6534 MVAR. Losses in reactors, based on the available data are estimated at 150 kW for 60 MVA phase unit or 0.25%. Since the reactive power from shunt reactors was zero, the total losses were only due to the capacitor losses.

The ITS Loss Study Working Group calculated the loss values attributable to capacitors and reactors to be 0.0037% for Demand Loss and 0.0010% for Energy Loss.

B. Catenary/Equivalent Adjustment

Losses due to catenary distances in load flow equivalent consist of two components: 1) losses that occur as “I squared R” losses but are not included in the load flow due to the use of “sight” distances rather than actual wire distances, and 2) the equivalent of short tap transmission lines (that is, representing a short tap as a junction on the main transmission line).

In 1987, the Engineering Departments of both Georgia Power and Oglethorpe Power stated that the catenary distance (conductor length) is approximately 1.5% greater than the “sight” distance of a span of transmission line. An additional 0.5% represents the short tap transmission connections that are not represented in the load flow model.

The ITS Loss Study Working Group estimates these losses as 2.0% of the bulk transmission and subtransmission losses (demand and energy). This calculation results in a value of 0.0405% for Demand Loss and 0.0327% for Energy Loss.

C. Contact Resistance Loss

Losses attributable to contact resistances are those electrical losses associated with switches, connectors and terminations resulting in heat production at the contact point and in the device. Load current flowing through the device and the resistance of the device (contact resistance and the resistance of the device itself) combine to product the “I squared R” heating effect.

The Engineering Departments of both Georgia Power and Oglethorpe Power stated that contact resistances (switches, connectors and terminations) vary but are measured in micro-ohms ($\mu\Omega$). They are negligible in comparison to the transmission line resistances (which are represented within load flow).

The ITS Loss Study Working Group agreed that these losses exist, but when compared to other system losses they are practically negligible. The group assigned a value to this component of 0.0001% for both Energy Loss and Demand Loss.

D. Corona Loss

Corona is a phenomenon which exists on high-voltage transmission lines (conductors). Corona exists when the electric field intensity (voltage gradient) “exceeds the threshold” or ionizes the atmosphere surrounding the conductor. This field intensity is approximately 3000 kV/m. Corona losses depend mostly on the voltage level of the conductor, but are also influenced by the presence of water vapor, air pressure, conductor material and incident photoionization. The ionization of the air generates heat, light, audible noise and radio interference. These examples are all forms of energy release that must be supplied by the transmission system.

Corona loss is weather dependent and is larger during inclement weather. Since peak conditions on the ITS usually occur during optimal weather conditions, it is expected that demand corona loss will be less than energy corona loss. Using the research performed in 1987 by the ITS Loss Study Working Group and 2018 ITS transmission system miles data, the electrical losses attributable to corona are 0.0192% Demand Loss and 0.0883% Energy Loss. The impact of corona energy loss is due to the fact that all weather components are factored into the result, and corona energy loss does not relate on a percentage basis because it is independent of line loading.

E. Deviation from Base Case Interchange Schedules Loss

Electrical losses attributable to the deviation from base case interchange schedules are a result of the difference between the load flow base case system interchange and the actual system interchange. The abundance of short-term economic transactions and deviations from contractual off-system sales is impractical to account for in the modeling for energy consumption. Thus, a correction for the mismatch between base case interchange and actual system interchange may be needed. If the actual system interchange is less than the base case schedule, the adjustment will be negative.

The base case interchange schedule accurately reflects the actual system conditions during peak load levels. As a result no adjustment is necessary for demand losses or energy losses.

F. Deviation in Inadvertent Interchange (Loop Flow) Loss

Economic sales and purchases of electrical energy occur on an hourly basis between interconnected electrical systems. The decision to purchase or to sell energy for one hour is predicated on the economics of the available fuel mix and transmission costs (wheeling charges). When transactions are made between electrical energy suppliers, a dedicated transmission path is usually designated to carry the energy from one party to the other. However, power flows over the transmission path of least impedance. Thus, some energy transactions affect the transmission systems of third parties without any wheeling charges being levied. The Integrated Transmission

System, with its abundance of 500 kV transmission facilities, has in the past been the third party to some of these transactions.

By assigning electrical losses attributable to deviations in inadvertent interchange, an attempt is made to capture losses for loop flows (Energy which flows completely through a transmission system) which occur on the ITS. Based on the work done by the 1987 ITS Loss Study Working Group, the new value of loss is 0.0277% for Demand Loss and 0.0500% for Energy Loss.

G. E/M Fields Loss

Electrical losses attributable to E/M (Electromagnetic) fields from conductors are those losses which result from the magnetic coupling of the phase conductors to their surroundings. This magnetic coupling is the same fundamental coupling effect for electrical transformers. Thus, this loss is analogous to the “No Load” losses for a transformer.

For the Demand Loss component, the ITS Loss Study Working Group estimates the losses to be 0.3% of the bulk transmission losses resulting in a Demand Loss value of 0.0057%. For the Energy Loss component, the Working Group estimates the loss factor to be 0.8% of System Peak Demand or 0.008% per unit Load Factor resulting in a value of 0.0143% for Energy Loss.

H. Harmonic Distortion Loss

Harmonic Content is the distortion of sinusoidal waveforms characterized by indication of the magnitude and order of Fourier series terms describing the wave. The harmonic content of the electric field coincides with that of the line voltage, and the harmonic content of the magnetic field coincides with that of the line current for single-phase systems. For transmission lines, the harmonic content is small, except during transient conditions, and of little concern for the purpose of field measurements except at points near large industrial loads such as saturated power transformers, n-pulse rectifiers, or aluminum and chlorine plants.

For the purpose of this study, we had no data that was measured anywhere on the system. The ITS Loss Group agreed to assume that the current harmonics on the system are not larger than limits outlined in IEEE 519-1992 application guide for harmonics. Based on that data, estimated current system harmonics on the ITS are around 2.58%. As the amount of non-linear load grows on the system, the amount of harmonics is expected to increase. The working group calculated the value of loss attributable to harmonic distortion to be 0.0017% for Demand Loss and 0.0014% for Energy Loss.

I. Insulator Leakage Loss

Losses due to insulator leakage are those electrical losses which result from a current flowing from the electrical conductor (bus bar or switch) to ground. This current is caused by the potential difference between the conductor and ground and the internal resistance of the insulator (or insulating device). The electrical loss is real power loss that results from heating of the insulator. This heating is represented by the square of the current times the resistance or “I squared R”. The leakage current is a function of the conductor voltage and the insulator resistance (not a function

of the load current). The resistivity of the insulator may be affected by contamination, moisture and/or insulator damage (lightning and gunshot damage).

The ITS Loss Study Working Group calculated the value of losses due to insulator leakage to be 0.0197% Demand Loss and 0.0352% Energy Loss.

J. Line Out Operation Adjustment

Periodically, transmission lines are removed from service for maintenance and for emergency conditions. Less transmission lines in-service results in additional loading on the remaining lines in-service, thus incrementally increasing the resistive power losses (I^2R) on the system. Additional real power losses which occur as a result of this increased loading are attributable to line out operation.

An analysis was performed utilizing the base case model to determine the effect of line out operation on transmission system losses. The ITS Loss Study Working Group determined the value of losses attributable to line out operation to be 0.0041% for Demand Loss and 0.0018% for Energy Loss.

K. Overhead Ground Wire (OHGW) Loss

Losses due to induced current in the OHGW loop are those electrical losses which result from the magnetic coupling of the overhead ground wire and the three electrical phases. This coupling produces a voltage and induced current in the OHGW loop. This magnetic coupling is the same fundamental coupling effect for electrical transformers. Thus, this loss is analogous to the “No Load” losses for a transformer. The remainder of the loss occurs due to the resistive power loss (I^2R) from the induced current flowing in the OHGW loop. A 1987 EMTP study conducted by Mr. R. A. (Bobby) Jones of Southern Company Services investigating the benefits of segmenting the OHGW was utilized in preparing an estimate of OHGW loss.

The ITS Loss Study Working Group estimates these losses as 1.4% of the bulk transmission and subtransmission losses (demand and energy). This calculation results in a value of 0.0284% for Demand Loss and 0.0229% for Energy Loss.

L. Power Factor Adjustment

Electrical losses attributable to reactive loads are those real power losses resulting from an increase in the magnitude of current by the reactive component of the load. The reactive component of the load current has an impact on the magnitude of the load current and therefore the losses associated with that current.

Based on the 2018 base case model, the ITS power factor is calculated to be 0.9626. Based on the real time data, during the peak, the power factor was calculated to be 0.9807 (slightly better than the value represented in the model). The Power Factor Adjustment calculated by the ITS Loss Study Working Group are -0.0273% for Demand Loss and +0.0023% for Energy Loss.

M. Temperature Compensation of Test Resistances Loss

Real power losses which occur on transmission line conductors are a function of conductor resistance. In turn, conductor resistance is dependent on conductor temperature (as the temperature of the conductor increases, so does the conductor resistance). When the power system is simulated with the load flow program, conductor resistance is not properly modeled, for varying temperatures and conductor loading. Temperature compensation of test resistances can result in an upward or a downward change in system losses, depending on system conditions.

The research performed by the ITS Loss Study Working Group shows that electrical losses attributable to temperature compensation of test resistances are negligible. The working group assigned 0.0000% Demand Loss and 0.0000% Energy Loss to be attributable to temperature compensation of test resistances.

N. Unbalanced System Operation Loss

Unbalanced system operation losses are those electrical losses which result from operation of the power system with phase currents and voltages that are not equal in magnitude and not exactly 120 electrical degrees apart. System unbalance results from unbalanced loads and transmission lines that have slightly different impedance characteristics in each phase due to either a non-equidistant phase spacing or not utilizing phase transposition. System unbalance also results from mutual coupling between parallel lines.

In 1987, an EMTP study set up by Mr. Hamish Wong of Southern Company Services and conducted by Mr. R. A. (Bobby) Jones also of Southern Company Services provided the working group with enough information to make an estimate of the loss due to unbalanced system operation.

The ITS Loss Study group estimates the loss due to unbalance as:

- 1.0% of the sum of the bulk transmission, the 230/XX and 115/XX kV transformers and the subtransmission losses for the demand component of loss. This calculation results in a value of 0.0252% for Demand Loss, and
- 1.75% of the sum of the bulk transmission, the 230/XX and 115/XX kV transformers and the subtransmission losses for the energy component of loss. This calculation results in a value of 0.0359% for Energy Loss.

O. Unmetered Auxiliary Equipment

Losses defined as the energy used by unmetered auxiliary equipment is the energy used by regulators, current transformers, potential transformers, relays, etc. that is not metered. This energy is the energy required for the device to work (both "I squared R" and "No Load" losses).

Based upon a review of typical potential transformer burdens realized in the GPC system, the ITS Loss Study Working Group estimates a constant loss of 650 kW for the entire system. This loss constant results in a value of 0.0024% for Demand Loss and 0.0043% for Energy Loss.

APPENDIX

Table 1. Unit-out Probabilities (Peak)

Rank	Units Outaged	Number of Units Outaged	Probability (Rounded)	Sum of Probabilities
1	No Outages	0	69.62%	69.62%
2	1-Bowen	1	11.32%	80.94%
3	1-Wansley	1	4.57%	85.51%
4	1-Scherer	1	4.44%	89.95%
5	1-Farley	1	2.78%	92.73%
6	1-Vogtle	1	1.98%	94.72%
7	1-Hatch	1	1.82%	96.54%
8	1-McDonough CC	1	0.80%	97.33%
9	1-McIntosh CC	1	0.50%	97.84%
10	1-Franklin CC	1	0.19%	98.03%
11	1-Bowen 1-Wansley	2	0.52%	98.55%
12	1-Bowen 1-Scherer	2	0.50%	99.05%
13	1-Bowen 1-Farley	2	0.32%	99.37%
14	1-Bowen 1-Vogtle	2	0.22%	99.59%
15	1-Bowen 1-Hatch	2	0.21%	99.80%
16	1-Wansley 1-Scherer	2	0.20%	100.00%

Table 2. Unit-out Probabilities (Off-Peak)

Rank	Units Outaged	Number of Units Outaged	Probability (Rounded)	Sum of Probabilities
1	No Outages	0	29.34%	29.34%
2	1-Bowen	1	24.73%	54.07%
3	1-Scherer	1	8.65%	62.72%
4	1-Wansley	1	8.28%	71.00%
5	1-McDonough CC	1	3.86%	74.86%
6	1-Hatch	1	3.15%	78.02%
7	1-Farley	1	3.01%	81.02%
8	1-Franklin CC	1	2.77%	83.79%
9	1-Vogtle	1	2.22%	86.01%
10	1-McIntosh CC	1	2.00%	88.01%
11	1-Bowen 1-Scherer	2	2.14%	90.15%
12	1-Bowen 1-Wansley	2	2.05%	92.20%
13	1-Bowen 1-McDonough CC	2	0.96%	93.15%
14	1-Bowen 1-Hatch	2	0.78%	93.93%
15	1-Bowen 1-Farley	2	0.74%	94.68%
16	1-Bowen 1-Franklin CC	2	0.69%	95.36%
17	1-Bowen 1-Vogtle	2	0.55%	95.91%
18	1-Bowen 1-McIntosh CC	2	0.49%	96.40%
19	1-Scherer 1-Wansley	2	0.72%	97.12%
20	1-Scherer 1-McDonough CC	2	0.33%	97.45%
21	1-Scherer 1-Hatch	2	0.27%	97.73%
22	1-Scherer 1-Farley	2	0.26%	97.99%
23	1-Scherer 1-Franklin CC	2	0.24%	98.23%
24	1-Scherer 1-Vogtle	2	0.19%	98.42%
25	1-Scherer 1-McIntosh CC	2	0.17%	98.59%
26	1-Wansley 1-McDonough CC	2	0.32%	98.91%
27	1-Wansley 1-Hatch	2	0.26%	99.17%
28	1-Wansley 1-Farley	2	0.25%	99.42%
29	1-Wansley 1-Franklin CC	2	0.23%	99.65%
30	1-Wansley 1-Vogtle	2	0.18%	99.83%
31	1-Wansley 1-McIntosh CC	2	0.17%	100.00%

Table 3. Hydro Schedule Used For 2018 Energy Cases

Hour	Summer Weekday	Summer Weekend	Winter Weekday	Winter Weekend	Spring/Fall Weekday	Spring/Fall Weekend
0100	Motoring/ Pumping	Motoring/ Pumping	Motoring	Motoring	Motoring/ Pumping	Motoring/ Pumping
0200	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping
0300	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping
0400	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping
0500	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping
0600	Motoring/ Pumping	Motoring/ Pumping	Winter Low Water	Motoring	Motoring/ Pumping	Motoring/ Pumping
0700	Motoring/ Pumping	Motoring/ Pumping	Winter Normal	Motoring	Summer Low Water	Motoring/ Pumping
0800	Motoring/ Pumping	Motoring/ Pumping	Winter Normal	Winter Low Water	Summer Low Water	Summer Low Water
0900	Motoring/ Pumping	Motoring	Winter Normal	Winter Low Water	Summer Low Water	Summer Low Water
1000	Summer Low Water	Motoring	Winter Normal	Winter Normal	Summer Low Water	Summer Low Water
1100	Summer Low Water	Motoring	Winter Normal	Winter Low Water	Summer Low Water	Motoring/ Pumping
1200	Summer Normal	Summer Normal	Winter Normal	Winter Low Water	Summer Low Water	Motoring/ Pumping
1300	Summer Normal	Summer Low Water	Winter Normal	Motoring/ Pumping	Summer Low Water	Motoring/ Pumping
1400	Summer Normal	Summer Normal	Winter Low Water	Motoring/ Pumping	Summer Low Water	Motoring/ Pumping
1500	Summer Normal	Summer Normal	Winter Low Water	Motoring/ Pumping	Summer Low Water	Motoring/ Pumping
1600	Summer Normal	Summer Normal	Winter Low Water	Motoring	Summer Normal	Motoring/ Pumping
1700	Summer Normal	Summer Normal	Winter Normal	Winter Low Water	Summer Normal	Summer Normal
1800	Summer Normal	Summer Normal	Winter Normal	Winter Normal	Summer Normal	Summer Normal
1900	Summer Normal	Summer Low Water	Winter Normal	Winter Normal	Summer Low Water	Summer Low Water
2000	Summer Low Water	Summer Low Water	Winter Normal	Motoring	Summer Low Water	Summer Low Water
2100	Summer Low Water	Summer Low Water	Winter Low Water	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping
2200	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping
2300	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping
2400	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping	Motoring/ Pumping

**Table 4. Load Shapes Used For 2018 Energy Cases
(Fractions of peak Demand)**

Average Hourly Percentages of ITS Peak Load for Each Daytype						
Hour Ending	Summer (defined as June1 - Sept 30)		Winter (defined as Dec 1 - Feb 29)		Fall/Spring (defined as Mar 1 - May 30 and Oct 1 - Nov 30)	
	SWD	SWE	WWD	WWE	FWD	FWE
100	0.5227	0.5290	0.4829	0.5087	0.4490	0.4407
200	0.4956	0.4977	0.4767	0.5002	0.4351	0.4231
300	0.4813	0.4774	0.4796	0.4991	0.4314	0.4153
400	0.4807	0.4661	0.4962	0.5049	0.4400	0.4157
500	0.5029	0.4658	0.5372	0.5196	0.4733	0.4245
600	0.5459	0.4718	0.6009	0.5438	0.5333	0.4425
700	0.5706	0.4819	0.6314	0.5714	0.5614	0.4628
800	0.5904	0.5164	0.6223	0.5911	0.5592	0.4850
900	0.6218	0.5616	0.6064	0.5915	0.5576	0.4991
1000	0.6650	0.6093	0.5932	0.5761	0.5623	0.5061
1100	0.7088	0.6568	0.5782	0.5589	0.5666	0.5106
1200	0.7489	0.7018	0.5649	0.5448	0.5737	0.5185
1300	0.7849	0.7395	0.5564	0.5309	0.5829	0.5284
1400	0.8101	0.7677	0.5501	0.5211	0.5914	0.5385
1500	0.8270	0.7903	0.5496	0.5187	0.6004	0.5495
1600	0.8379	0.8050	0.5610	0.5302	0.6106	0.5624
1700	0.8364	0.8083	0.5863	0.5603	0.6200	0.5787
1800	0.8227	0.7957	0.6225	0.6001	0.6275	0.5880
1900	0.8013	0.7698	0.6330	0.6112	0.6314	0.5923
2000	0.7813	0.7449	0.6251	0.6079	0.6307	0.5924
2100	0.7506	0.7164	0.6024	0.5931	0.6094	0.5760
2200	0.6897	0.6630	0.5673	0.5679	0.5650	0.5371
2300	0.6253	0.6043	0.5313	0.5399	0.5158	0.4951
2400	0.5704	0.5527	0.5047	0.5170	0.4782	0.4608

Table 5. Weighting For 2018 Energy Bulk Loss Calculations

	Days/Year Represented By Each Daytype	Daily MWH Losses By Each Daytype	Annual MWH Losses By Each Daytype	Daily MWH Load By Each Daytype	Annual MWH Load By Each Daytype
Summer Week Day	87	6,462.64647	562,250	441,438	38,405,141
Summer Week End	35	5,987.25984	209,554	415,194	14,531,777
Winter Week Day	63	4,862.04173	306,309	333,226	20,993,267
Winter Week End	27	4,739.30430	127,961	331,363	8,946,802
Fall/Spring Weekday	110	4,461.37803	490,752	319,458	35,140,380
Fall/Spring Weekend	43	4,326.72992	186,049	305,737	13,146,708
Total	365		1,882,875		

159,208 Total Annual Energy 500/230/115 kV Transformer No-Load Losses (MWh)

Total Annual Energy Losses 2,042,083

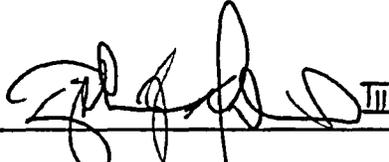
Total Annual Load 131,164,074

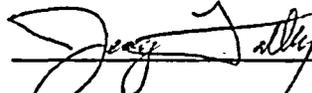
Energy Loss Factor (B) 1.5330% LF = Loss/(Load + Loss)

ITS JOINT SUBCOMMITTEE FOR TRANSMISSION PLANNING

2018 ITS LOSS STUDY

APPROVAL PAGE

 9/20/2018
Will McDaniel – Dalton Utilities / Date

 9/20/18
Jeremy Talley – Dalton Utilities / Date

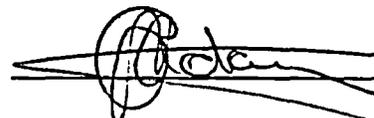
 9/20/2018
Joe Sowell – GTC / Date

 9/20/2018
Bob Casey – GTC / Date

 9/20/18
Jack Comer – SCS / Date

 9/20/18
Jeff Stansel – GPC / Date

 9/20/18
Ben Boucher – MEAG Power / Date

 9/20/18
Gary McAdam – MEAG Power / Date

[E]

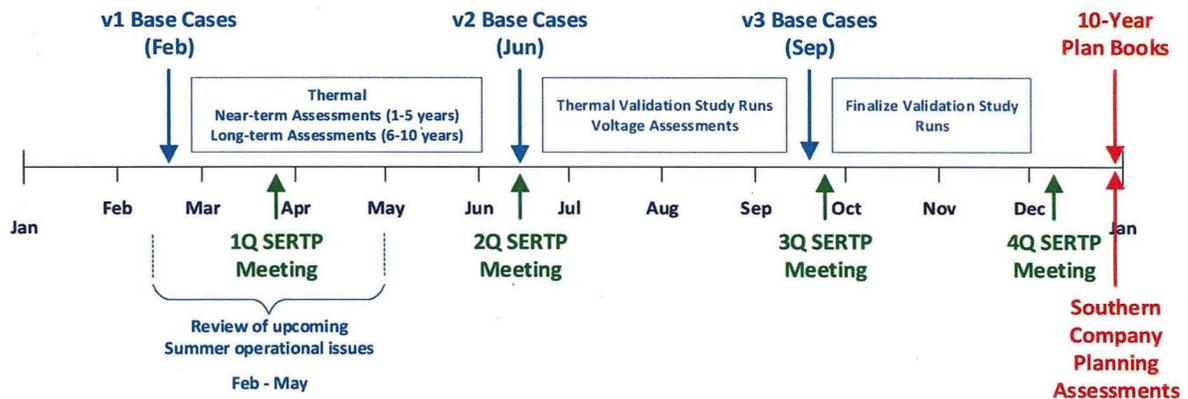
**INTERFACE AND
INTERCONNECTIONS**

[E1]

REGIONAL TRANSMISSION PLANNING

SERTP

Southern Company participates in the Southeastern Regional Transmission Planning (SERTP) process, which is a coordinated, open and transparent process that allows for stakeholder (e.g. any interested party) feedback regarding the current ten-year transmission expansion plan. In the SERTP process, stakeholders have the opportunity to propose alternatives to projects in the latest transmission expansion plan for Southern Company to consider. The SERTP has expanded several times, both in the scope and in the size of the region, since its initial voluntary formation and now includes the following Sponsors: Southern Company, Dalton Utilities, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas & Electric Company and Kentucky Utilities Company, the Ohio Valley Electric Corporation, including its wholly owned subsidiary Indiana-Kentucky Electric Corporation, Associated Electric Cooperative Inc., the Tennessee Valley Authority, and Duke Energy (Duke Energy Carolinas, LLCs and Duke Energy Progress, Inc.). The SERTP process did not produce any stakeholder-proposed alternatives that were included in the ITS Ten-Year Transmission Expansion Plan (2019-2028). Additional information on the SERTP process is available on the SERTP website at <http://www.southeasternrtp.com/>. The timeline below shows where the SERTP Stakeholder meetings fall during the annual planning process.



Also of note, the SERTP began implementing the additional requirements of FERC Order No. 1000 on "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities", on June 1, 2014, including:

- Participation in a regional planning process, including the development of a single, regional transmission plan
- Consideration of transmission needs driven by public policy requirements established by state, federal, or local laws or regulations, including stakeholder input regarding these types of transmission needs
- Development of qualification criteria for non-incumbent transmission developers to propose transmission projects for the purposes of regional cost allocation
- Development of a regional cost allocation methodology to allocate costs of those regional facilities selected in a regional plan for purposes of cost allocation

- Development of a common interregional cost allocation methodology to allocate costs of those interregional facilities selected in two neighboring regional plans for purposes of cost allocation

No transmission project proposals were submitted during the 2018 SERTP process for potential inclusion in the regional transmission plan for purposes of cost allocation.

EIPC

Southern Company, along with several other transmission Planning Authorities across the Eastern Interconnect, participate in the Eastern Interconnect Planning Collaborative (“EIPC”). The EIPC is a coordinated, open, and transparent process that models the impact of various policy options determined to be of interest by state, provincial, and federal policy makers and other stakeholders. Analysis performed in the EIPC is used to “inform” transmission Planning Authorities responsible for the analysis/development of the respective transmission expansion plan. The EIPC did not produce any projects proposed in the ITS Ten-Year Transmission Expansion Plan (2019-2028). Additional information on the EIPC is available on the EIPC website at <http://www.eipconline.com>.

[E2]

**TRANSMISSION SERVICE REQUEST
SUMMARY**

The table below lists key transmission service requests (TSRs) confirmed from 1/1/2016 through 1/10/2019 within the Georgia Integrated Transmission System.

[E3]

**SOUTHERN COMPANY ELECTRIC
SYSTEM INTERFACE ANALYSIS**

Introduction

Electric power transfers can have a significant effect on the reliability of the electric power system for a balancing authority and must be evaluated in the context of the entire interconnected system. The physics of interconnected transmission systems dictate the flow patterns involved in a bulk power transfer. Therefore, significant parallel flows across many balancing authorities beyond those specifically involved in the transaction are commonplace. Evaluations performed in a joint and/or coordinated manner are essential for maintaining the capability and reliability of the system for the benefit of all users. The scope of these joint and/or coordinated evaluations is to assess the transfer capabilities between the Southern Balancing Authority (SBA) and its neighboring balancing authorities. From a SBA reliability standpoint, the import capabilities are a consideration in providing a reliable and cost-effective system for the customers of the Southern Companies' operating companies, which includes Georgia Power Company (GPC).

On behalf of GPC and the other operating companies of the Southern Companies, SCS Transmission Planning conducts various joint coordinated evaluations with neighboring systems and internal screens intended to track transfer capabilities with neighboring balancing authorities over a 10-year period. These evaluations are performed on an annual basis. The following sections describe the methods by which this is accomplished through the 10-year planning horizon and summarize the results from the most recent evaluation.

Terminology

In the evaluation of transfer capability, there are many terms and acronyms. In addition, there are many regional organizations and individual companies that influence the practices and methodologies used in interface analysis. Section H4 in the Appendix provides technical definitions of the terminology and acronyms used in this section.

Open Access Same-time Information System (OASIS)

As part of Federal Energy Regulatory Commission (FERC) Order 889, all FERC jurisdictional utilities are required to maintain and post on an OASIS site the transfer capabilities of its balancing authority's interfaces. For the Southern Companies, this is done on a rolling thirteen (13) month basis (operations planning). All reservations for transmission service must be made through interaction with the OASIS sites of the SBA (Southern Companies, Georgia Transmission Corporation (GTC), and the Municipal Electric Authority of Georgia (MEAG)). Information relating to firm service that has been granted or reserved can be obtained through access to the various OASIS sites. For information on the OASIS of Southern Companies, please visit the OASIS website at www.oasis.oati.com/SOCO. This document contains OASIS data as of November 2018.

Southern Balancing Authority Transfer Capability

The ability to import power from outside sources is one of the many factors considered in developing a reliable and cost-effective plan for the SBA, including GPC.

It should be emphasized that the base case used to calculate these transfer capabilities represents one snapshot of the system. There are great multitudes of transactions between balancing authorities that can and do occur, and it would be impossible to predict the actual transfer capability for any given future point in time. Therefore, as previously mentioned, the calculation and posting of transfer capabilities is only performed in the operations planning horizon (rolling 13 months). Furthermore, actual power flows resulting from energy transactions do not necessarily follow their scheduled contract paths, and the resulting parallel flows can greatly influence the transfer capability on an interface to which the scheduling parties are not even directly connected. Although the actual real – time transfer capability can be very difficult to predict, this coordinated practice of interface analysis has allowed the electric system to take advantage of economically beneficial, and emergency, bulk power transfers to provide a reliable and cost-effective system for the retail customers in the SBA, including GPC. For more information on the Available Transfer Capability (ATC) calculation methodology utilized in the operations planning horizon, please visit the ATC Implementation Document (ID) on the OASIS website at:

https://www.oasis.oati.com/SOCO/SOCOdocs/SOCO_ATCID.pdf.

Methodology for Evaluating Transfer Capability in the Planning Horizon

Transmission transfer capabilities for the SBA are evaluated in accordance with North American Electric Reliability Council (NERC) planning and transfer capability guidelines and are designed to meet all firm obligations, including Transmission Service Agreements (TSA), Capacity Benefit Margin (CBM), Transmission Reliability Margin (TRM), and Native Load Reservations (NLR).

The evaluation of transfer capability begins with power flow base cases, each one representing a snapshot of the future. These cases are developed in coordination with many regional and balancing authorities' representatives. For example, the annual SERC Reliability Corporation Long - Term Study Group (LTSG) databank update and NERC Multi – regional Modeling Working Group (MMWG) are data sources for external system representations used to develop the power flow base cases for the SBA evaluations. These power flow base cases include the modeling of power transfers that represent existing contractual obligations between balancing authorities that are expected when the database update occurs. Immediately prior to major joint interface evaluations such as the LTSG or Florida Interface studies, the SBA and outside areas of the models are updated by the participating utilities. For internally performed (non – joint) evaluations, the SBA portion of the base cases is updated with the latest information regarding modeling assumptions.

For the “northern” interfaces of Midcontinent Independent System Operator (MISO), Tennessee Valley Authority (TVA), Duke, South Carolina Public Service Authority (SCPSA) and South Carolina Electric & Gas (SCE&G), importing power on one interface may mutually impact the ability to import power on the other interfaces. Therefore, transfer capability for the SBA is evaluated to ensure not only that there is sufficient import capability across each interface to accommodate all firm transactions across that particular interface, but also that there is sufficient import capability across all of the interfaces to accommodate all firm obligations simultaneously. The Florida interface is

fundamentally radial from the SBA and would not have significant impact on the “northern” interfaces. The Florida interface is jointly evaluated with the Florida utilities and will be discussed separately from the “northern” interfaces.

There are many transactions modeled in the base cases between various companies. Before any transfer evaluation begins, a list of firm transactions involving the SBA for the relevant periods is obtained from the OASIS and applicable transactions are added to the cases as base transfers.

In general, linear, DC analysis is used to perform transfer capability analysis on all interfaces except Florida, and AC analysis is used in the joint studies with the Florida utilities. Along the Florida interface, heavy reactive power flows under certain conditions preclude the effective use of DC analysis, so AC analysis is used.

Ten Year Interface Capability Plan for SBA

Adequate transfer capability of the SBA should be maintained to:

1. Support contractual sales and/or purchases
2. Ensure reliable operation of the system

Because the transmission providers within the SBA have an obligation to provide firm transmission service to all transactions that are granted “firm” service, transfer capability on the interfaces should be maintained to meet these obligations for importing power as listed on the OASIS for SBA members. This is significant in fulfilling the obligations listed in item 1 above.

Per its order 888, FERC allows balancing authorities to reserve capacity on the interfaces to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. This reservation is called Transmission Reliability Margin. For the SBA, this import transfer capability value is established at 900 MW which is then divided between the MISO (216 MW), TVA (278 MW), Duke (338 MW) and Florida (68 MW) interfaces. For more information on the TRM methodology, please visit the TRM Implementation Document (ID) on the OASIS website at:

[https://www.oasis.oati.com/SOCO/SOCOdocs/Transmission Reliability Margin Implementation Document \(TRMID\).pdf](https://www.oasis.oati.com/SOCO/SOCOdocs/Transmission%20Reliability%20Margin%20Implementation%20Document%20(TRMID).pdf).

Additionally, FERC allows native load and network customers to reserve import interface capability for future load growth purposes. Southern Companies, on behalf of the Operating Companies (which includes GPC), may maintain native load transmission reservations across external interfaces with neighboring utilities in order to facilitate the Company in procuring off system reliability capacity and energy which is needed because there is some uncertainty in the projection of native – load generation capacity requirements. This uncertainty is the result of economic conditions, weather, load forecast uncertainty and unanticipated (long – term) generation unit failure or retirements. The amount of interface native load reservation capacity is influenced significantly by the present and projected markets for power supply, both inside the SBA and outside the SBA. There is one interface reservation for future native load growth on the TVA (200 MW) interface. This interface native load reservation is in support of access to renewable wind energy resources across this interface.

Per its order 888, FERC also allows native load customers to reserve import interface capability to ensure access to adequate capacity resources outside of the SBA to maintain system reliability and to reduce the amount of generation reserves required. This reservation of interface capacity is termed Capacity Benefit Margin (CBM). Studies are performed periodically to determine the amount of generation capacity reserves and emergency interface capacity (CBM) required to maintain system reliability in a cost-effective manner for the customers of the Operating Companies, including GPC. The most recent approved study indicates that 1,050 MW of CBM will maintain the appropriate reserve margin level. The ability to obtain and import power for CBM is a function both of the transmission system and the availability of power on the other side of the interfaces under consideration. Because there is a distinct probability that all 1,050 MW may not be available from a single neighboring balancing authority, CBM is reserved across several neighboring balancing authorities. The balancing authorities chosen for allocation of CBM are those anticipated to have available excess resources and transfer capability at the time when CBM is most likely to be utilized. For more

information on the CBM methodology, please visit the CBM Implementation Document (ID) on the OASIS website at:

https://www.oasis.oati.com/SOCO/SOCODocs/SOCO_CB MID.pdf.

Import Capability

The methodology for calculating import capability on the “northern” interfaces of MISO, TVA, Duke, SCE&G and SCPSA has been described in some detail in earlier parts of this document. The evaluation performed to develop the 10-year projection of adequate import capability on these interfaces to meet existing firm commitments utilizes the most recent internal base cases available at the time of the study. The cases are modified to remove all export transactions that may mask problems that can occur if the export transactions are not scheduled during the time when significant imports into the system are needed. This impact is typically called “netting”. For the import evaluation, the cases were further modified to import all TSAs, NLRs, CBM, and TRM for the applicable interfaces. The import capability from Florida is evaluated jointly with the Florida utilities and is discussed in the “Florida” section below.

Northern Interfaces

Import capability across all of the interfaces with the SBA is sufficient to accommodate all firm transactions including TSAs, NLR, TRM and CBM for all years.

Florida interface

Import capability from the Florida Reliability Coordinating Council (FRCC) to SBA is sufficient to accommodate all firm transactions including TSAs, TRM and CBM for all years.

PowerSouth Interfaces

There is one other interface with the SBA. This is an internal interface with the PowerSouth Energy Cooperative (PSEC) balancing authority. The import capability, as well as the typical available generation at peak periods, from the PSEC system is significantly lower than the external interfaces of the SBA listed above. The interface with PSEC plays a much lesser role in the reliability and, in general, economic import

capability for the SBA. There are no NLRs, CBM, or TRM reservations for this interface. Therefore, the internal interface with PSEC has been excluded from the discussions.

[E4]

**OPTIMUM TRANSMISSION SITES
FOR GENERATION
IN GEORGIA**

Interconnection

As part of the IRP, the Company has provided the Georgia Public Service Commission information regarding preferred sites on the transmission system for interconnection of new generation. Previously, information regarding preferred sites was posted publicly online and updated quarterly. This same information was also provided to the Commission in IRP filings. The last update was posted in December 2017 and is provided in this section of the IRP.

As of 2018, this information is no longer posted. Southern Company currently offers public access to completed study reports and the opportunity to initiate new requests through its OASIS website. The list of completed study reports available include transmission service studies and generator interconnection request studies, which can both be found on Southern Company's OASIS website under the Transmission Studies/Studies folder. A copy of any non-CEII study report listed is available upon request, where CEII denotes Critical Energy Infrastructure Information. These generator interconnection study reports are good indicators of typical interconnection upgrades, general interconnection costs and schedules, and interconnection study results for specific points of interconnection.

Southern Company also offers a pre-application report process that can provide information about the transmission system facility ratings at a specific point of interconnection on its transmission system for any customer. The pre-application report results can allow developers to conduct their own screening for siting potential generation. This pre-application report request form can also be found on Southern Company's OASIS website for a standard charge of \$300 per report.

December, 2017

Optimum Interconnection Sites - North Georgia

County	State	Potential Area of Interconnection	Delivery Voltage
Banks, Hall	GA	Gainesville	230 or 500
Cherokee, Dawson, Forsyth	GA	Ball Ground, Cumming, Dawsonville	230
Clarke, Jackson, Oconee	GA	Athens, Center	230
Gwinnett, Dekalb	GA	Metro Atlanta, Lawrenceville, Suwanee, Snellville	230 or 500
Walton, Newton, Barrow, Rockdale	GA	Monroe, Covington, Winder, Conyers	230

Optimum Interconnection Sites - Central Georgia

County	State	Potential Area of Interconnection	Delivery Voltage
Baldwin, Hancock, Putnam, Washington	GA	Milledgeville, Devereux, Eatonton, Sandersville	230 or 500

Optimum Interconnection Sites - South Georgia

County	State	Potential Area of Interconnection	Delivery Voltage
Appling	GA	Baxley	230 or 500
Glynn	GA	Thalman, Brunswick	230 or 500
Lowndes	GA	Pine Grove	230
Tift	GA	Tifton	230 or 500

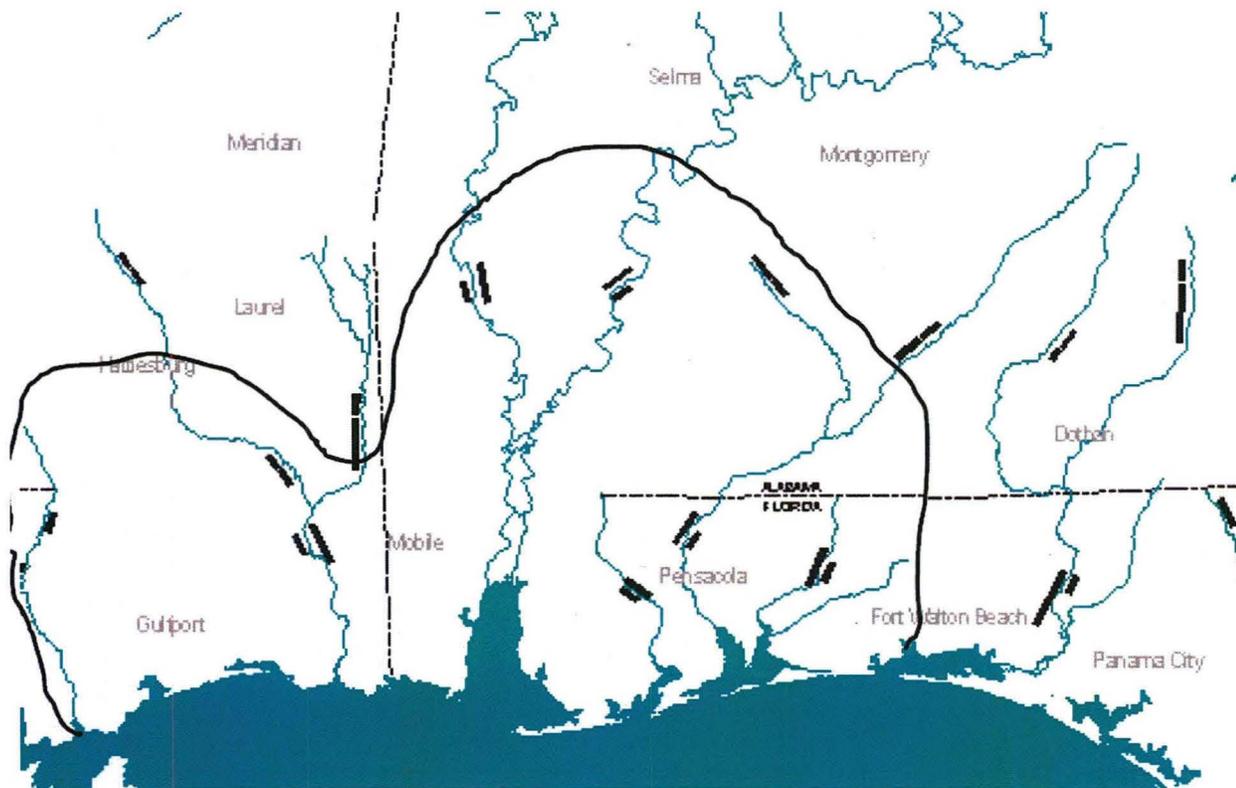
Note: Based on a transmission perspective. Other sites in close proximity to the areas listed may offer similar capabilities. The need for transmission improvements may not be equal in all listed areas and may be impacted significantly by the choice of generation connecting voltage and magnitude of addition. Also, improvements may be impacted by other generation development within or external to the control area.

Stability Constrained Areas

Area
Southwest Quadrant. Includes coastal Mississippi, Alabama, and Florida.

Note: The boundaries of stability limited areas could change based upon dispatch and load patterns. The boundaries shown extending outside of the Southern Control Area are approximate. There are currently no stability limited areas within Georgia.

Southwest Quadrant



[F]

**GPC DISTRIBUTION SUBSTATION
PROJECTS & FORECAST
(FIVE-YEAR LOADING PLAN)**

**DISTRIBUTION SUBSTATION FORECAST
(FIVE-YEAR LOADING PLAN)**

The following items outline the distribution expansion plans for Georgia Power:

- ◆ Ten Year Substation Load Forecast (on file in GPC Area Planning Department)
- ◆ Five-Year Construction Budget & Forecast (attached)
- ◆ Distribution Substation Project File

These plans are dynamic and are revised on an annual basis. Substation projects have the longest equipment lead times and require more advance planning. However, it is not efficient to plan distribution feeder improvement work years in advance since construction lead times are relatively short and system changes occur frequently. These changes are usually initiated by unforeseen new business loads that may alter the priority of distribution expenditures. Substation planning is accomplished by performing a ten-year peak loading forecast. Banks that exceed Georgia Power's "Transformer Loading Guidelines" are candidates for upgrade projects if load shifts are not possible. A five-year budget is then prepared for these banks.

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

<i>Project Name</i>	<i>Cost</i>	<i>Need Date</i>
GEORGIA PACIFIC (WARRENTON) CAPACITY INCREASE Customer is adding approximately [REDACTED] which will require a substation capacity increase	[REDACTED]	2/21/2019
PROJECT HANWAH Q SOLAR New industrial customer in Carbondale Industrial Park.	[REDACTED]	3/1/2019
BUCKHEAD POINT SUBSTATION Convert the Buckhead Point 115/7.2 kV substation to 115/12 kV	[REDACTED]	6/1/2019
COLEMAN CAPACITY ADDITION This project adds a second bank at the Coleman (Sav) substation	[REDACTED]	6/1/2019

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

Project Name	Cost	Need Date
NORTHWINDS SUBSTATION		6/1/2019
<p>Construct the Northwinds 230/25 kV area substation on property purchased previously on projects [REDACTED]. The station is located off of Teasley Drive in Alpharetta about 1800 ft west of Kimball Bridge substation. Construct a high side ring bus with (3) - 230kV breakers and one 60 MVA 230/25 kV LTC Bank. Make the ring bus easily expandable in the future for (3) additional 230kV ring breakers and (3) additional 230/25 kV Banks. Install one 25kV, 2000A LS bank breaker. Construct (2)- 25kV buses with (1) -1200A, 25kv feeder breaker on bus #1 and (2) - 1200A, 25kv feeder breakers on bus #2. Install 25 Kv, 1200A bus tie switches between 25kV Bus #1 and #2. All feeder exits will be underground. Install animal protection on the 25kV bus. Loop the Alpharetta-Ocee 230kV line, approximately 1700', into the new Northwinds 230/25 kV substation. Install fiber optic cable from Alpharetta to Northwinds substation approximately a distance of 2.2 miles to form the Alpharetta-Ocee 230kV Fiber Optic Line. At Alpharetta substation modify the existing line terminal with DCUB pilot relaying to use fiber cable instead of power line carrier. Distribution to install duct lines, cables, overhead work and switching cubicles and construct (3) distribution feeders. Install 6- 6" duct bank (Network design & install)-600 feet, Install 12 - 6" duct bank (Network design & install) - 2450 + 1450 feet for circuit #3. This project resolves three bank loading contingencies at Old Alabama Rd and Kimball Bridge Rd. substations in 2019 and 2020. This project resolves three normal feeder loading issues and one contingency feeder loading issue at Old Alabama Rd and Kimball Bridge Rd in 2019 and 2020. This project was ranked [REDACTED] on the 2019 Transmission Rating and Ranking list..</p>		
PEACH ORCHARD 2019 BANK C CAPACITY INCREASE		6/1/2019
<p>In 2019, Peach Orchard Bank C 12/13.8kV 10.5MVA transformer reaches [REDACTED]</p>		
TWILIGHT BANK B RERATE		6/1/2019
<p>Increase area distribution bank capacity available during a bank outage contingency by rerating the Twilight 115/25kV Bank B. Upgrade Twilight Lowside Bank B disconnect switches W1027 and W1029 from 1200A switches to 2000A switches to allow for a bank rerate of 61.73MVA. Bank B (T10656) nameplate rating is 56MVA but is limited to 51.84MVA by the existing lowside bank breaker disconnect switches. Upgrade lowside bank breaker bypass switch W1025 from a 1200A switch to a 2000A switch. Upgrade all lowside bank related jumpers from 1590 AAC to double 1590 AAC jumpers (This includes all jumpers related to the low side of the bank, W1024, W1025, W1027 and W1029). Change relay settings as needed to accommodate the bank rerate. Upgrade any other components needed to accommodate the bank rerate. Replace station service cabinet, it is old and rusty. Add station service fuses and AC disconnect switch. Remove station service meter base.</p>		

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

Project Name	Cost	Need Date
<p>VALLEY HILL BANK A RERATE</p> <p>Increase area distribution bank capacity available during a bank outage contingency by rerating the Valley Hill 115/25kV Bank A. Upgrade Valley Hill Bank A Lowside Switch H1119 from a 1200A switch to a 2000A switch to allow for a bank rerate of 63.8MVA. Bank A nameplate rating is 56MVA but is limited to 51.84MVA by the existing lowside switch. Upgrade 1590 AAC lowside jumpers to double 1590 AAC jumpers. Upgrade any other components needed to accommodate the bank rerate. Change relay settings as needed to accommodate the bank rerate.</p>		6/1/2019
<p>WELCOME ALL ROAD BANK ADDITION</p> <p>BUS: Split the existing bus (Bus 1) to create a second bus (Bus 2) for the new bank (Bank B) Install (1) 2000A 25kV bus-tie breaker and disconnect switches (at Bay 3) Relocate existing PCB 1152 and its underground exit to Bay 3 to make room for Bank B on Bay 2 and connect to Bus 2 Install station service throw overBANK Install (1) new 230/25kV 60MVA LTC bank (Bank B) at Bay 2 Install new high side bus work Install (1) high-side 230kV AIM with bypass blades Install (1) 2000A 25kV low-side bank breaker at Bay 2 Install station service and Bus PTs to the new Bus 2 BANK A: Install (1) 25kV 1200A feeder breaker and disconnect switches at Bay 6 Install extension to the feeder bay (Bay 6) to add this feeder breaker Relocate Bus PTs Remove RLB W1119 and install (1) 2000A 25kV low-side bank breaker in its place (at Bay 5) 7113As requested by Substation Design and Support, replace 25kV obsolete breaker Co. No. B-4404 as a companion project to TEAMS Project (Welcome All Road Bank Addition). 7172 Replace obsolete AIM SWITCH 171217, TYPE Mark II, associated with Bank A. Replace RLB SW# 219 and SW#211</p>		6/1/2019
<p>NORTH ATHENS CAPACITY INCREASE</p> <p>Bank D (115/12kV) at North Athens will be loaded to . Banks A, B, & C (46/12kV) provide back-up; they will be loaded to . In addition, the 46 kV line feeding North Athens will be loaded . The North Athens circuits will not tie with circuits from the surrounding stations, as the 115 bank is set up to tie with the 46 kV banks</p>		7/1/2019
<p>MURRAYVILLE AREA LOAD GROWTH</p> <p>Load Growth in Murrayville, particularly at Fieldale Farms (Murrayville) will on the 46 kV system at Fieldale Farms (Murrayville) during normal operations and contingencies.</p>		10/1/2019

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

<i>Project Name</i>	<i>Cost</i>	<i>Need Date</i>
BURKHALTER ROAD 115/12-KV SUBSTATION The Burkhalter 115/12kV Bank A will reach [REDACTED] Install 2nd 25 MVA Bank and split the feeders.	[REDACTED]	12/1/2019
CONCORD ROAD TIMELY LAND PURCHASE Purchase property directly adjacent to the Concord Road 115/12kV substation or in the general area that will be needed to rebuild the substation in 2020 or 2021. The property needs to be large enough to accommodate a minimum of two distribution transformers and a mobile. Concord Road substation has two banks serving 12kV load in an isolated pocket within a 20kV area. [REDACTED]	[REDACTED]	12/30/2019
GARDEN CITY SUBSTATION (NEW) TIMELY LAND This project acquires a new substation site in Garden City in the vicinity of the Georgia Ports Authority near Savannah.	[REDACTED]	12/31/2019
QUITMAN PRIMARY - QUITMAN #1 69KV LINE REBUILD Approved 12/7/17 In 2019, the Quitman Primary to Quitman #1 69kV line section of the Quitman Primary-South Brooks 69kV line loads [REDACTED] for the loss of the Spain source and all 69kV load is fed from Quitman Primary. This section of line is composed of 4/0ACSR 50C rated conductor. On the Quitman Primary - South Brooks 69kV line, rebuild the 0.95 mile line segment between Quitman Primary and Quitman #1 with 115kV spec 336ACSR 100C construction. The 69kV study and solution were accepted by the STWG on May 22 2017. This project ranked [REDACTED] on the 2019 Transmission Project Rating and Ranking list.	[REDACTED]	12/31/2019
SOUTH CHATHAM AREA 46KV RETIREMENT Construct new 115/13.8kV substation on 2.8 acre site located between Lewis Drive and Television Circle in Savannah. Rebuild the Oglethorpe Mall substation in Savannah to 115/13.8kV spec. Add (3) 115kV breakers(Mk. BULO, New Purchase, [REDACTED]) to the Truman Parkway substation in Savannah.	[REDACTED]	12/31/2019

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

<i>Project Name</i>	<i>Cost</i>	<i>Need Date</i>
SOUTHERN GATEWAY TIMELY LAND PURCHASE This project acquires a 2 acre sub site for the new Southern Gateway industrial park in Bulloch County.	[REDACTED]	12/31/2019
GARDEN CITY SUBSTATION PROJECT Construct a new 115/25kV Garden City substation in the GA Ports area in Savannah. Project to also create a 46kV Grange Road switching substation in Savannah.	[REDACTED]	6/1/2020
SOUTH WADLEY 115/12KV SUB (WADLEY-MILLEN 46KV VOLTAGE ISSUE) For the loss of the Wadley Primary 115/46kV bank and all area load served from Millen Primary. [REDACTED] [REDACTED] This project will construct a new 115/12kV substation to move the current South Wadley load to the 115kV system and retire and remove the existing South Wadley 46/12kV substation.	[REDACTED]	6/1/2020
DEMOREST AREA CAPACITY INCREASE - TIMELY LAND PURCHASE Purchase a parcel of land for a future Demorest 115/12 kV substation.	[REDACTED]	12/31/2020
CONCORD GROVE 115/20KV SUBSTATION Build the new Concord Grove 115/20kV substation to ultimately replace the Concord Rd 115/12kV substation. See [REDACTED] for the land purchase.	[REDACTED]	6/1/2021

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

Project Name	Cost	Need Date
<p>CONCORD ROAD SUBSTATION REBUILD PROJECT</p> <p>Concord Road Substation is a two bank substation serving an isolated pocket of 12kV in an otherwise 20kV service area. Due to space constraints there is no room for a mobile transformer. [REDACTED] A bus tie breaker cannot be installed due to clearance issues [REDACTED]. The existing 12kV bus work is [REDACTED] which prevents a bank re-rate or replacement with larger units. The existing 115kV circuit switcher arrangement restricts the driving isle and prevents installation of a larger footprint transformer. All feeder breakers have [REDACTED]. The feeder breaker isolating and transfer switches are rated [REDACTED] which restricts feeder loading.</p>	[REDACTED]	6/1/2021
<p>EATONTON AREA 46 KV CAPACITY PROJECT</p> <p>Substation issues include the following: 2010: Tri County EMC converted North Eatonton to 25kV service. 2016: Banks A, B, & C at Eatonton City are expected to reach [REDACTED] 46 kV line work issues include the following: 2017: 2.6 miles of 4/0 ACSR between Eatonton Primary B & Highway 16 PM [REDACTED]; 3.0 miles of 4/0 ACSR between Highway 16 PM & North Eatonton [REDACTED] Project Proposal: Remove / retire existing Eatonton City 46/12 kV substation and construct new Eatonton City 115/12 kV 25 MVA substation which removes [REDACTED] from 46 kV system.</p>	[REDACTED]	6/1/2021
<p>HARGROVE ROAD CAPACITY ADDITION</p> <p>Increase capacity at Hargrove Road substation to maintain contingency reserve for loss of Bank A [REDACTED]. Install a third 115/20 kV bank and provide space for two future feeder positions.</p>	[REDACTED]	6/1/2021
<p>SILK HOPE AREA DISTRIBUTION PHASE II</p> <p>Project to build new 230/25kV substation and convert (2) 13.2kV distribution feeders to 25kV.</p>	[REDACTED]	11/15/2021

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

Project Name	Cost	Need Date
<p>BRASELTON AREA CAPACITY INCREASE</p> <p>A new 2,000 lot residential development is being planned in GPC territory on the south side of Hoschton. [REDACTED]</p>	[REDACTED]	12/31/2021
<p>CARMEL CHURCH 115/25/12KV SUBSTATION PROJECT</p> <p>GPC will construct the Carmel Church (a.k.a. East Mansfield) 115/25/12kv substation. GTC will construct the Mill Pond 115/12kv substation and the 115kv T-Line from the end of the Alcovy Rd - Pony Express 115kv line to Mill Pond substation via the Carmel Church substation. Load growth east of Jackson Lake and south of the city of Mansfield is [REDACTED]. This project is the second stage of a multi stage plan to improve service to the area by providing a new 115 kV source to the growth area.</p>	[REDACTED]	12/31/2021
<p>DEMOREST CAPACITY INCREASE</p> <p>GPC requires additional capacity in the Demorest area. Piedmont College is [REDACTED] Demorest Bank A [REDACTED]. This will bring the "normal" peak load on Demorest A to [REDACTED]. This is accomplished through an automatic throwover. The winter load for the the throwover is around [REDACTED]. The peak winter load, with the HMC thrown over and a year of growth, is around [REDACTED].</p>	[REDACTED]	12/31/2021
<p>MEDICAL ARTS TIMELY LAND PURCHASE</p> <p>This project acquires a sub site in the East/Central area of Savannah to facilitate the retirement of the Cornel Ave 46kv substation.</p>	[REDACTED]	12/31/2021

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

<i>Project Name</i>	<i>Cost</i>	<i>Need Date</i>
<p>NORTH CLARKESVILLE 46/12 CAPACITY INCREASE PROJECT</p> <p>In 2021, North Clarkesville 46/12 KV substation will be greater [REDACTED]</p>	[REDACTED]	12/31/2021
<p>ROBERTS ROAD 115/25 KV CAPACITY ADDITION</p> <p>Projected loads for new mixed use developments will cause loading issues on [REDACTED]. Increase capacity at Roberts Road substation.</p>	[REDACTED]	12/31/2021
<p>LEWISTON 115/12KV SUBSTATION</p> <p>Based on area loading [REDACTED], construct a new 115/12kV area substation.</p>	[REDACTED]	12/1/2022
<p>NORTH THOMSON 115KV AREA SUBSTATION</p> <p>When [REDACTED], build new 115/25/12kV substation on previously purchased site.</p>	[REDACTED]	12/1/2022
<p>AEROTROPOLIS SUBSTATION ADVANCED LAND PURCHASE</p> <p>Purchase a fee simple substation site suitable for a new 115/20kV area substation on or near the west side of Hartsfield-Jackson airport property in the vicinity of the East Point - Mountain View 115kV line [REDACTED]. The site should be approximately [REDACTED]</p>	[REDACTED]	12/31/2022

Local Area Substation and Transmission Line Projects [5 Year] - Public Disclosure

<i>Project Name</i>	<i>Cost</i>	<i>Need Date</i>
<p>MADISON AREA CAPACITY INCREASE</p> <p>Bank A at Madison 46/12kV will [REDACTED]. South Madison's Banks A, B, & C were manufactured in [REDACTED] respectively. South Madison's Bank D was manufactured in [REDACTED]. Madison Bank A - [REDACTED] Madison Bank B - [REDACTED] Bank C at Madison Primary (GTC) was manufactured in [REDACTED]</p>	[REDACTED]	12/31/2022
<p>CERTAINTEED AREA CAPACITY INCREASE</p> <p>The load in the Industrial area around Certainteed [REDACTED]</p>	[REDACTED]	12/31/2023
<p>MEDICAL ARTS SUBSTATION PROJECT</p> <p>This project retires the Cornell Avenue substation in Savannah and constructs the Medical Arts Substation.</p>	[REDACTED]	12/31/2023

[G]

BUDGETING

[G1]

**AVERAGE INCREMENTAL COST
OVERVIEW**

Profitability / Reliability Incremental Cost Evaluation Model Overview

Georgia Power's Profitability / Reliability Incremental Cost Evaluation Model (PRICEM) uses inputs from both Distribution and Transmission to calculate an average incremental cost to be used in the financial evaluation of future projects. The PRICEM model applies these additional capacity costs based on the impact of the added load on the system demand. The objective is to ensure adequate resources to maintain operational flexibility and customer reliability.

Distribution Average Incremental Cost Methodology

In 2018, Georgia Power Company commissioned a study to re-evaluate Distribution Average Incremental Costs. This study considered recently completed and future projects for both Distribution substations and feeder projects. Details from this study are shown in the corresponding sections for both substations and feeders.

Distribution Substations

The Company compiled a list of recently completed and future distribution substation projects from 2016 through 2020. This sample of 26 projects was evaluated as to cost and additional capacity added. A per kW substation cost was calculated for the group of projects. The kW used in the study was added capacity, not added load. The result of the formula below provides the Company with the Distribution Substation Average Incremental cost.

$$\$/kW = \frac{\sum \text{(Project Costs in 2018 Dollars)}}{\sum \text{(Delta kW Capacity)}}$$

Note: A power factor of .97 was used to convert kVA capacity to kW capacity.

Distribution Feeders

A similar dollar per kW capacity study was done in 2018 for distribution feeders. The Company extracted data from a GIS mapping system for approximately 1825 existing feeders to determine the average length of the “trunk feeder” portion of a feeder and the average length of the “tap lines” that pull off the main trunk feeder. The trunk feeder is the large conductor, three phase portions originating at the substation and often running for several miles to an open point, smaller conductor, or fewer than three phases. Tap lines are typically smaller conductor extensions that may have fewer than three phases. Current feeder construction cost estimates were used to establish the average cost per mile of distribution trunk feeders and tap lines. Using the average lengths and average cost per mile of trunk feeders and tap lines along with the feeder planning capacity limit of trunk feeders and tap lines allows the calculation of the separate cost per kW of capacity for each of these components of a distribution feeder.

$$\$/kW_{(\text{trunk feeder})} = \frac{\sum (\text{avg. trunk feeder mi. x costs per mi.})}{\sum (\text{trunk feeder planning capacity limit})}$$

$$\$/kW_{(\text{tap line})} = \frac{\sum (\text{avg. tap line mi. x costs per mi.})}{\sum (\text{tap line planning capacity limit})}$$

Since trunk feeder and tap line planning capacity limits are proportional to the feeder voltage, a blended average of 25 kV feeder \$/kW costs and lower voltage feeder \$/kW costs was used.

$$\$/kW = \frac{(\$/kW @ 25 \text{ kV} + \$/kW @ \text{less than 25 kV})}{2}$$

Note: A power factor of .97 was used to convert kVA capacity to kW capacity.

Transmission Average Incremental Cost Methodology

The following methodology is used annually to estimate the marginal cost of transmission (\$/kW) by determining the average cost to add load at existing substations utilizing the transmission planning base case models.

- Load is increased at a substation until the first transmission constraint is identified.
- A transmission project is then estimated and implemented in the case to alleviate that first constraint.
- Load is then further increased at that substation until a second transmission constraint is identified.
- The estimated cost of the transmission project is divided by the load growth afforded by the transmission project between the first and second constraints.
- This process is repeated and averaged for substations across the Southern Company footprint.

$$\$/kW = \text{Average} \left(\frac{\text{Project Cost}}{kW \text{ Growth}} \right)$$

[G2]

**BUDGETING & BUDGET
CONTROL**

Transmission Capital Project and Blanket Approval

This procedure describes the funding approval process for Transmission capital projects and blankets.

Transmission Capital Project Approval

Early each year, Southern Company Services Transmission Planning-East, GPC Area Planning, and GPC Transmission Support review transmission project requests and work with the budgeting team to develop the upcoming budget.

Southern Company Services Transmission Planning-East identifies projects and presents them to Transmission management during a rating and ranking review. These are projects that have NERC compliance requirements and upcoming growth needs. This ranking identifies the most critical projects to be submitted for budget consideration.

Georgia Power Company Area Planning and GPC Transmission Support submit their budget needs for ongoing projects and programs in addition to any projects identified through routine inspections of the Transmission system. Once these requests have been compiled, the budgets are presented to Transmission management for review. Details are presented on the justification for the project, costs, schedule, and risks.

Upon completion of management review, Finance presents the budget request to the Transmission & Distribution (T&D) Council for consideration and approval. A review is done at a high level of detail on projects with factors including high costs, public exposure such as significant land acquisition, distribution duct systems, etc.

The T&D Council reviews the proposed budget and recommends modification to these project requests as necessary and then approves the final budget submission. Any project over \$5,000,000 will be taken to the T&D Council for spend approval once it is ready to begin.

Once the budget cycle is complete, new project requests less than \$500,000 are approved by the Project Manager and sent to the Finance Supervisor for funding. Any project over \$500,000 will go through the Transmission Project Review Team (TPRT) (representatives from multiple areas of Transmission including planning, design, operations, and scheduling). The projects are presented to the TPRT where they review the justification, technical solution, and schedule.

Once approved, the projects are routed to the Finance Supervisor who reviews the project funding requirements to determine how to proceed. If the project costs less than \$1,000,000, the Finance Supervisor reviews and approves the project if acceptable.

If the project costs are more than \$1,000,000 but less than \$5,000,000, the Supervisor reviews and approves the project and sends to a General Manager for final approval.

Projects with costs greater than \$5,000,000 are reviewed by the Supervisor and, if acceptable, are presented to the T&D Council for final approval.

Any increase in project costs or significant scope changes after approval must be approved by the appropriate level as outlined above with the exception that minor scope changes in projects and/or allocation of project dollars between budget years can be approved by the Finance Supervisor without functional management approval.

Once projects are approved, engineering groups or the Land Department can create work orders in TEAMS.

When Capital Projects are for business units other than Transmission, the Finance Supervisor will get business unit management approvals before sending these projects forward through the approval process (e.g. modification to transmission facilities for generation).

T&D Capital Blanket Approval

True Blankets: (Transmission Maintenance: equipment failures, Transmission Maintenance Center jobs, spare equipment blankets, e.g. PE 6000, 6010, 6030, 6075, 7010, 7070; Other: PE 6002 NESC, PE 6427 grounding – Projects must have estimates in TEAMS and can have schedules)

Distribution True Blankets – e.g. PE 5500 through 5514 (including outdoor lighting), PE 7000 through 7099 (excluding Transmission projects) and PE 8060. The actual estimates and DWEs are created in JETS.

The Finance Supervisor reviews funding level requests from the various T&D business units and recommends funding levels to the T&D Council for consideration and approval. Blanket owners present significant changes in budgetary needs to the T&D Council at this time.

The T&D Council reviews and approves funding level requests, if acceptable, which authorizes spending to these approved levels.

Limited Blankets: (e.g. PE 6005, 6006, 6020, 6021, 6100, 6640, 6899, 7640, 8000, 8040 – Projects must have estimates and schedules)

Limited Blanket individual projects must go through the normal project approval process outlined above.

Formal BCA Approvals:

Initial BCA or BCA with changes less than \$500,000 plant additions: Project Manager

Initial BCA or BCA with changes more than \$500,000 and less than \$1,000,000 plant additions: TPRT

Initial BCA or BCA with changes greater than \$1,000,000 but less than \$5,000,000 plant additions: TPRT & the General Manager.

Initial BCA or BCA with changes greater than \$5,000,000 plant additions: TPRT, General Manager, T&D Council, and Vice President.

Exhibit 1 below illustrates all authorized approval limits outlined in this procedure.

**Exhibit 1
Authorized Approval Limits**

Project Approval Authorizations

Project Cost	Authorized Approval
Less Than or Equal to \$500,000	Project Manager
Greater Than \$500,000 & Less Than \$1,000,000	Transmission Project Review Team (TPRT)
Greater Than \$1,000,000 & Less Than or Equal to \$5,000,000	TPRT & General Manager
Greater Than \$5,000,000	TPRT, General Manager, T&D Council, & Vice President

Budget Change Authorizations Approvals

Budget Change Authorization Cost	Authorized Approval
Less Than or Equal to \$500,000	Project Manager
Greater Than \$500,000 & Less Than \$1,000,000	TPRT
Greater Than \$1,000,000 & Less Than or Equal to \$5,000,000	TPRT & General Manager
Greater Than \$5,000,000	TPRT, General Manager, T&D Council, & Vice President

Blanket Authorizations Approvals

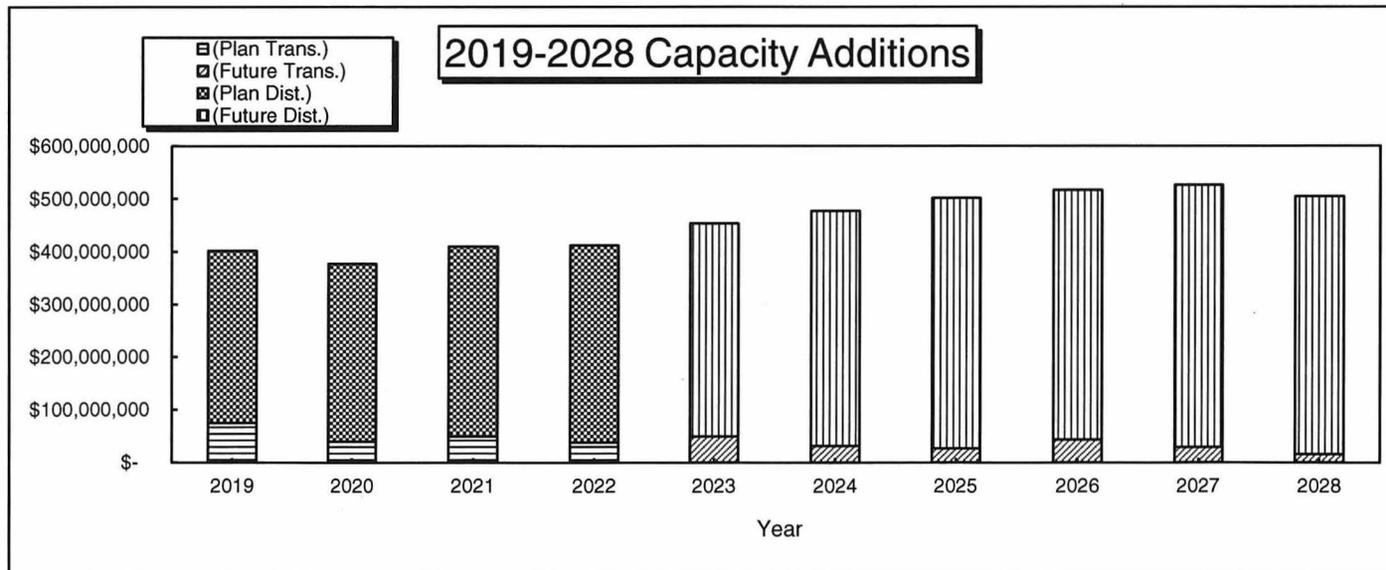
Budget Change Authorization Cost	Authorized Approval
Less Than or Equal to \$300,000	Estimator
Greater than \$300,000 & Less than or Equal to \$500,000	Project Manager
Greater Than \$500,000 & Less Than \$1,000,000	TPRT
Greater Than \$1,000,000 & Less Than or Equal to \$5,000,000	TPRT & General Manager
Greater Than \$5,000,000	TPRT, General Manager, T&D Council, & Vice President

[G3]

**POWER DELIVERY CAPACITY
ADDITION EXPANSION PLAN**

**POWER DELIVERY CAPACITY ADDITION EXPANSION PLAN
2019-2028**

	NETWORK		LOAD SERVING		TOTALS
	(Plan Trans.)	(Future Trans.)	(Plan Dist.)	(Future Dist.)	
1 2019	\$ 75,088,456		\$ 326,244,241		\$ 401,332,696
2 2020	\$ 39,912,449		\$ 337,208,113		\$ 377,120,562
3 2021	\$ 49,388,938		\$ 360,284,747		\$ 409,673,685
4 2022	\$ 38,360,558		\$ 373,371,778		\$ 411,732,335
5 2023		\$ 49,698,352		\$ 403,460,230	\$ 453,158,582
6 2024		\$ 31,461,448		\$ 445,342,741	\$ 476,804,189
7 2025		\$ 26,563,823		\$ 475,165,483	\$ 501,729,307
8 2026		\$ 43,593,866		\$ 472,690,172	\$ 516,284,038
9 2027		\$ 28,997,821		\$ 497,192,398	\$ 526,190,220
10 2028		\$ 16,128,940		\$ 488,318,325	\$ 504,447,265
	\$ 202,750,401	\$ 196,444,251	\$1,397,108,879	\$2,782,169,349	\$4,578,472,879



[G4]

**APPROVED PROJECTS
(BCA WITH DOCUMENTATION)**

BUDGET CHANGE AUTHORIZATIONS

A Budget Change Authorization (BCA) is a document that describes certain information about a project, including:

- Project Name
- Project ID Number
- Need Date for the overall project and for individual items within the project
- Description (scope) for the overall project and for individual items within the project
- A brief Supporting Statement
- Costs for each item, by year
- Overall cost of the project, and, if applicable, the change from any previously authorized amount

When completed, the BCA is routed through various levels of management to attain project approval. In addition to the BCA itself, a package of documentation is attached, including:

- A document detailing background and problem description, study assumptions, discussion of any viable alternatives, recommendations, maps, drawings and other supporting data
- A detailed engineering and construction schedule
- A listing of materials and estimates of their procurement and installation costs

Budget Change Authorizations and supporting documentation for all approved Transmission Planning projects approved since the 2016 IRP filing are included in the attached CD. A sample project follows.

**SOME INFORMATION IN THE
SAMPLE BCA HAS BEEN
REDACTED.**

**THE CD ATTACHMENT WITH OTHER
BCAS AND SUPPORTING
DOCUMENTATION HAS BEEN
REDACTED.**

TPE (without Dist.) - BUDGET CHANGE ROUTING

TEAMS # 11662

Project Name: McIntosh 230/115kV Bank Replacement

- BCA-B BCA-S BCA-L BCA-E
- New Project or Revised
- * Less than \$1,000,000
- ** \$1,000,000 to \$5,000,000
- *** Greater than \$5,000,000
- N.O. Point Change Y N

Approved by:

TEAMS Role:

Date:



Originator	<u>8/7/17</u>
TP Project Manager	<u>8/7/17</u>
Project Manager	<u>8/11/17</u>
Proj. Controls Supv.	
Manager, Project Mgmt.	<u>9-1-17</u>
Lead Project Manager	<u>09-05-17</u>
Manager, TP-East	<u>9/6/17</u>
TP Admin - East	<u>9/6/17</u>
Project includes line work)	
Manager, Area Planning	<u>9/17/17</u>
BCC	<u>8/17/17</u>
Date	<u>9-14-17</u>
)	
Budget Coordinator	<u>10/16/17</u>
G.M. PIng. & Admin.	<u>10/2/17</u>
) V.P. Transmission	

*, **, *** indicate Final Approval depending on total cost

T & D Rank (if applicable) _____

wa.

ITS Category (circle one)

<input type="checkbox"/> ITS Parity	<input type="checkbox"/> ITS Parity & DSF	<input type="checkbox"/> Non-ITS
DSF	< \$100,000	For Info Only

TMCRR25
Page: 1 of 4
Project ID: 11662

GEORGIA POWER COMPANY
BUDGET CHANGE - From Saved Version

Date: 08/07/2017
Time: 01:40:36 PM

Originator : [REDACTED] Department TRANSMISSION PLANNING - EAST

Project Manager: [REDACTED]

Project Name: MCINTOSH 230/115-KV TRANSFORMER REPLACEMENT

Project Need Date: 06/01/2019

Estimated Start Date: [REDACTED] Present Budget: [REDACTED]

Latest Required Date: [REDACTED] This Revision: [REDACTED]

PE Number: 6499 Increase (Decrease): [REDACTED]

Category: TRANSMISSION Type: Capital

Region: COASTAL

Area: SOUTHERN-SAVANNAH

Approvals and Dates:

TP Project Manager	[REDACTED]	TP Project Manager	[REDACTED]
Project Manager	<i>M</i>	Controls Supervisor	[REDACTED]
Project Management Manager	[REDACTED]	Lead Project Manager	[REDACTED]
Rec. Mgr. Trans. Planning East	[REDACTED]	Mgr. Area Planning	<i>M</i>
Budget Control Committee	[REDACTED]	Gen. Mgr. Planning & Admin	[REDACTED]
BUDGET COORDINATOR	[REDACTED]		

Project Description:

Replace McIntosh 280 MVA, 230/115kV transformer (Bank ATX) with 400 MVA, 230/115kV transformer.

Supporting Statement:

Beginning [REDACTED], the McIntosh 230/115kV transformer loads to [REDACTED] of its 280 MVA Rate A capability [REDACTED] (Worst case)

Loss of [REDACTED] also loads McIntosh 230/115kV (Bank ATX) 102% of its [REDACTED] bonus rating.

TMCRR25

GEORGIA POWER COMPANY

Date:08/07/2017

Page: 2 of 4

BUDGET CHANGE - From Saved Version

Time:01:40:36 PM

Project ID: 11662

PE Item/ Project Item No.	Facility Name Fac Reqd Area Location Project Description	Ownr	Plt Addn Engr. Loc
---------------------------------	--	------	-----------------------

MCINTOSH

1166202	06/01/2019	GPCO	75-075
---------	------------	------	--------

Replace McIntosh Bank ATX to a 400 MVA 230/115kV transformer (currently 280 MVA).

Per communication with [REDACTED], install the spare 400MVA, 230/115kV bank, company number [REDACTED] that is currently stored in the 230kV yard at Kraft Substation. Test reports and drawings are located on the S: drive in the major equipment files. [REDACTED] will replace this bank with a new purchase spare. Include transportation cost to move the bank from Kraft to McIntosh in the estimate. [REDACTED] 5/29/2017

Scope update: Retire the 25kV Reserve Station Service circuit currently fed from the tertiary of the existing bank. Resource Planning has agreed that [REDACTED] [REDACTED] 6/13/2017

Notes:

- (1) [REDACTED] has confirmed there are no overstressed 115kV breakers with the new 400 MVA bank (breakers 946, 952, 962, 982 and 992). (Updated [REDACTED] 4/28/2016).
- (2) [REDACTED] bonus rating is based on 1600 amp low-side switches.

(3) May need to relocate Steam Plant Service. (Will retire station service to plant from the tertiary. [REDACTED] 6/12/17)

(4) Per [REDACTED] (10/21/15), the following relays need to be replaced: HCB (pilot wire / 25kV RSS circuit), HU-4, BDD, IAC, KC-4, TD-5 and (Will replace relays on separate projects. LVS-6/12/17)

(4b) at the McIntosh Steam Plant: HCB (pilot wire / 25kV RSS circuit) (Will replace on separate projects. [REDACTED] 6/12/17)

=====
P&C APPS
Add (1) SEL-387/GE-T60 - Autobank ATX
[REDACTED] 6/30/2017
=====

Control estimate by [REDACTED] 11/23/2015

- ESTIMATE INCLUDES:
- 1 BANK PANEL
 - 1 DCUB TREUTLEN LINE PANEL (SOCO STD)
 - 1 TRANSFER TRIP PANEL
 - 2 BREAKER CONTROL PANELS
 - 4 BUS DIFF PANEL (SOCO STD)
 - 1 BANK ALARM ANNUNCIATOR
 - CABLES
 - REMOVALS
 - CTRL DESIGN 700HRS
 - TEST 3120 HRS (3 PEOPLE)
 - APPS 224HRS

=====
Control estimate has been re-estimated per change of scope.
See estimate notes for more details.
[REDACTED] on 7/11/2017
=====

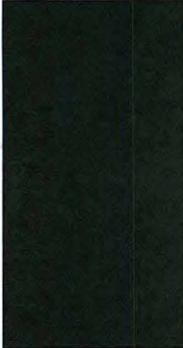
TMCRPR25
Page: 3 of 4
Project ID: 11662

GEORGIA POWER COMPANY
BUDGET CHANGE - From Saved Version

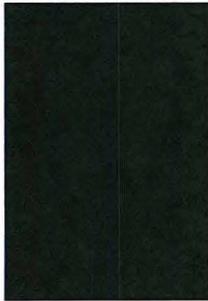
Date:08/07/2017
Time:01:40:36 PM

Items

Pe Item :
Proj Item :
Plt Add :
(CIAC) :
Net Add :
(Plt Tfr):
Removal :
(CIRC) :
(Salvage):
Cash Rqd :
OCR :



Pe Item : PE
Proj Item : Totals
Plt Add :
(CIAC) :
Net Add :
(Plt Tfr):
Removal :
(CIRC) :
(Salvage):
Cash Rqd :
OCR :



TMCRPR25
Page: 4 of 4
Project ID: 11662

GEORGIA POWER COMPANY
BUDGET CHANGE - From Saved Version

Date:08/07/2017
Time:01:40:36 PM

Item Expenditures by Year

PE Item :							
Proj Item :	1166202						
Budget Yr :	2018	2019	2020	2021	2022	Extended	Totals
Plt Add :							
(CIAC) :							
Net Add :							
(Plt Tfr) :							
Removal :							
(CIRC) :							
(Salvage) :							
Cash Rqd :							
OCR :							

Grand Totals

Budget Yr :	2018	2019	2020	2021	2022	Extended	Totals
Plt Add :							
(CIAC) :							
Net Add :							
(Plt Tfr) :							
Removal :							
(CIRC) :							
(Salvage) :							
Cash Rqd :							
OCR :							

** End of Report **

MCINTOSH 230/115kV TRANSFORMER REPLACEMENT**TEAMS# 11662****06/01/2019 Need Date***Document Version: 08/7/2017***I. Executive Summary**

In [REDACTED] the load on the system is modeled at [REDACTED] of the summer peak load. Because of the high temperatures the equipment capability is calculated to be less than normal. When utilizing this case the equipment is measured to the summer Rate A capability. In this Hot Weather analysis, the McIntosh 230/115kV transformer loads past its 280 MVA rate A capability [REDACTED]. Also, [REDACTED] [REDACTED] the Loss of [REDACTED] results in loading McIntosh 230/115kV (Bank ATX) above its [REDACTED] bonus rating.

The proposed solution is as follows (See Figure 1 Proposed on page 2):

- Replace McIntosh 280 MVA, 230/115kV transformer (Bank ATX) with 400 MVA, 230/115kV transformer.

Adjacent Projects in the Area are Goshen - McIntosh 115kV Reconductor 14730 (2016), McIntosh - McIntosh CC10 230 15226 (2017), Plant McIntosh HCB Pilot Wire Replacement Project 15993 (2017), and McIntosh (SCIP) PHASE II 15595 (2018).

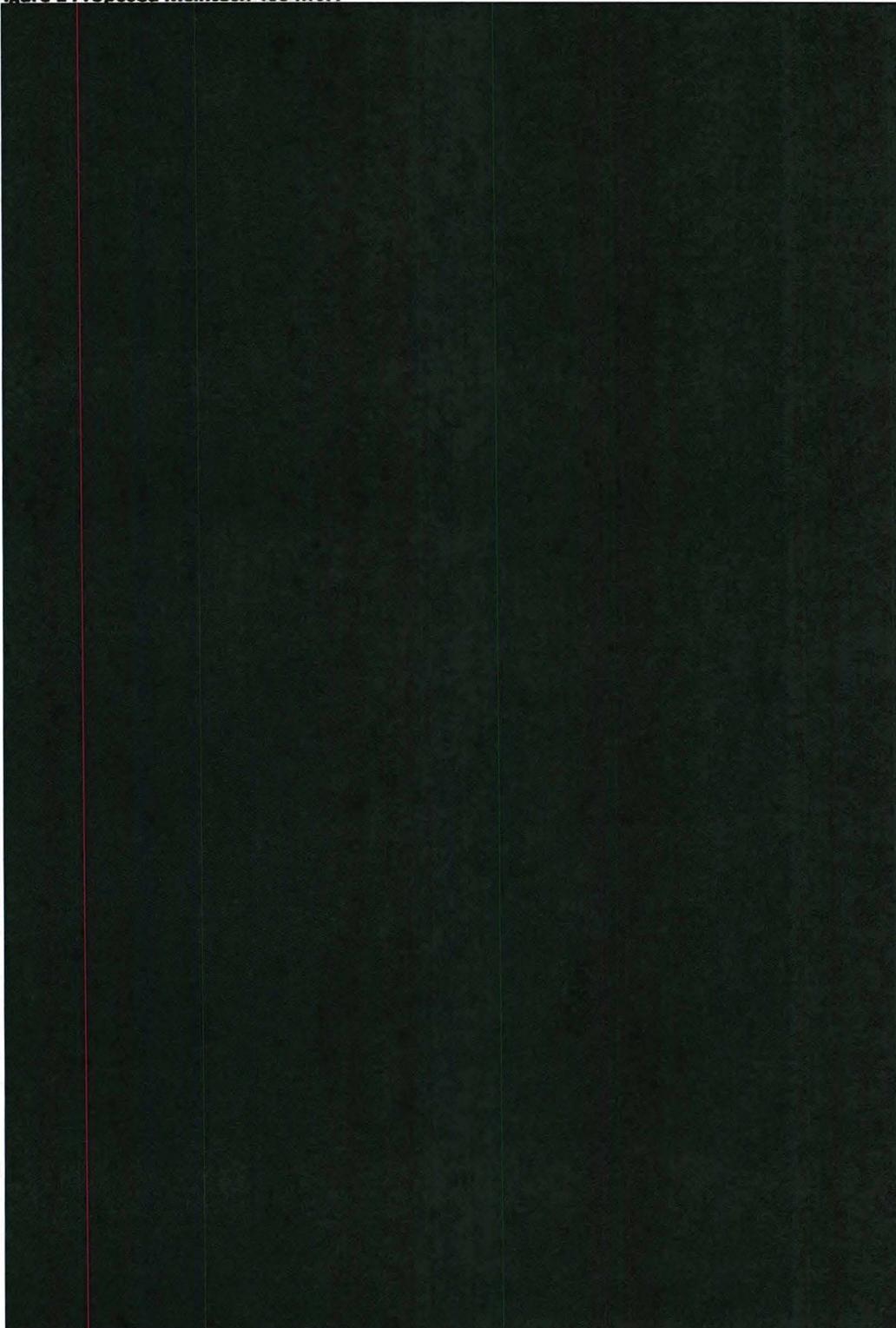
II. Compliance Statement

This project addresses problems associated with Category P3 events. These problems were identified as part of Southern Company's Transmission Planning process in compliance with NERC Standard TPL-001-4. These problems were formally referenced as Category B of the NERC Standard TPL-002-0.

CONFIDENTIAL – TRANSMISSION INFORMATION – THIS DATA SHOULD NOT BE SHARED WITH THE MERCHANT FUNCTION

CRITICAL ENERGY INFRASTRUCTURE INFORMATION: This data is confidential CEII and is subject to Regulation by CFR Sec. 388.113. Any and all duplication of this data must contain this notification. This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

Figure 1 Proposed McIntosh 400 MVA



CONFIDENTIAL – TRANSMISSION INFORMATION – THIS DATA SHOULD NOT BE SHARED WITH THE MERCHANT FUNCTION

CRITICAL ENERGY INFRASTRUCTURE INFORMATION: This data is confidential CEII and is subject to Regulation by CFR Sec. 388.113. Any and all duplication of this data must contain this notification. This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

III. Background and Problem Description

Plant McIntosh area is a major generation and transmission hub on the north side of the City of Savannah area (see Figure). The Generation Sources include McIntosh CT, McIntosh CT 5&6 and the McIntosh CC 10 & 11. The Transmission Corridors include 500kV lines to Vogtle & McCall Road, 230 & 115 kV interface lines to South Carolina, and 230 & 115 kV lines into North Savannah.

Ten Year Plan Study

The 10 Year Plan Study shows constraints beginning in Summer 2019.

Table 1 McIntosh 230/115kV Bank Largest Constraints

Year	Pre Contingency loading (MVA)	Percent load
2019	304	
2020	312	
2021	327	
2022	330	
2023	332	
2024	334	
2025	336	

Note: Hot Weather case (v1D 2017 Series).

2016 Category P6 N-2

Category P6 (N-2) five year study shows additional N-2 constraints on the McIntosh 230/115kV transformer (see

Figure 2 Category P6 N-2 McIntosh 230/115kV Constraints on page 3) and is also a contributor to constraints in the area (see Error! Reference source not found. on page Error! Bookmark not defined.).

Figure 2 Category P6 N-2 McIntosh 230/115kV Constraints

Year	Load Level	Zone	Post Contingency Problems	Post Corrective Problems	Contingency 1	Contingency 2	Constraint	Pre Contingency Loading	Post Contingency Loading
2018	H	219	Y	Y				79.6	120
2018	S	219	Y	Y				84.8	127.5
2019	S	219	B	Y				84.4	126.6
2020	H	219	T	N				89.1	104
2020	S	219	B	Y				75.9	112.9
2021	H	219	T	Y				74.2	110
2022	H	219	T	Y				75	111.6
2022	S	219	B	Y				80.4	118.6

CONFIDENTIAL – TRANSMISSION INFORMATION – THIS DATA SHOULD NOT BE SHARED WITH THE MERCHANT FUNCTION

CRITICAL ENERGY INFRASTRUCTURE INFORMATION: This data is confidential CEII and is subject to Regulation by CFR Sec. 388.113. Any and all duplication of this data must contain this notification. This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

IV. Study Assumptions

Ten Year Plan Study Assumptions:

- 2017 series V1C 2018-2027
 - Seasons: Summer, Shoulder, and Hot Weather (Hot Weather N-0 only).
 - Unit Dispatches: All Transmission Planning standard dispatch scenarios applied to each case.

V. Discussion of Alternatives

Preferred Plan: McIntosh 400MVA

Replace the existing 280 MVA, 230/115kV transformer with 400 MVA, 230/115kV transformer.

This will involve:

1. Replace the existing 280 MVA, 230/115kV transformer with 400 MVA, 230/115kV transformer. (Because of time constraints the new spare bank located at Kraft will be installed as the replacement bank at McIntosh.)
2. Retire the 25kV Reserve Station Service circuit currently fed from the tertiary of the existing bank. (Resource Planning has agreed that this feed will not need to be re-established until at least December 2021.)
3. Extending the existing foundations for the bank as the new bank size is longer than the existing bank size.

There are no overstressed 115kV breakers resulting from the install of the new 400 MVA bank (breakers 946, 952, 962, 982 and 992).

Alternative Plan: McIntosh 2nd 400MVA

Add an additional McIntosh 230/115kV 400MVA transformer to help with maintenance and N-2 constraints. This will involve:

1. *Replace equipment as outlined in the preferred plan above plus*
2. Extend 230kv Breaker-and-half Bus
 - a. Install 2 – 230kV Breakers
3. Extend 115kV Breaker-and-half Bus
 - a. Install 2 – 115kV Breakers
4. Install 2nd 400 MVA, 230/115kV transformer
5. Upgrade 9 – 115kV Breakers

CONFIDENTIAL – TRANSMISSION INFORMATION – THIS DATA SHOULD NOT BE SHARED WITH THE MERCHANT FUNCTION

CRITICAL ENERGY INFRASTRUCTURE INFORMATION: This data is confidential CEII and is subject to Regulation by CFR Sec. 388.113. Any and all duplication of this data must contain this notification. This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

If an additional McIntosh 230/115kV 400MVA transformer is added in parallel operation with the existing 230/115kV bank, the 9 – 115kV breakers will need to be upgraded due to overstress.

VI. Cost Estimate

Table 2 Preferred Plan Costs: McIntosh 400MVA

Item	Description	Cost
02	MCINTOSH: Replace McIntosh Bank ATX to a 400 MVA 230/115kV transformer (TTNB-MB) (currently 280 MVA). Retire tertiary bank serving station service to McIntosh Steam Plant	
Total		

Costs in italics are Planning Grade.

Table 3 Alternative 1 Costs: McIntosh 2nd 400 MVA

Item	Description	Cost
02	MCINTOSH: Replace McIntosh Bank ATX to a 400 MVA 230/115kV transformer (TTNB-MB) (currently 280 MVA).	
(a)	MCINTOSH: Extend 230kV Breaker-and-half Bus. Install 2 – 230kV Breakers.	
(b)	MCINTOSH: Extend 115kV Breaker-and-half Bus. Install 3 – 115kV Breakers.	
(c)	MCINTOSH: Install 2 nd McIntosh 400 MVA 230/115kV transformer.	
(e)	MCINTOSH: Upgrade 9 – 115kV Breakers.	
Total		

Costs in italics are Planning Grade.

CONFIDENTIAL – TRANSMISSION INFORMATION – THIS DATA SHOULD NOT BE SHARED WITH THE MERCHANT FUNCTION

CRITICAL ENERGY INFRASTRUCTURE INFORMATION: This data is confidential CEII and is subject to Regulation by CFR Sec. 388.113. Any and all duplication of this data must contain this notification. This document contains non-public transmission information and in accordance with FERC policy, should not be disclosed to Marketing Function employees.

VII. APPENDICES

Figure 3 McIntosh Arial

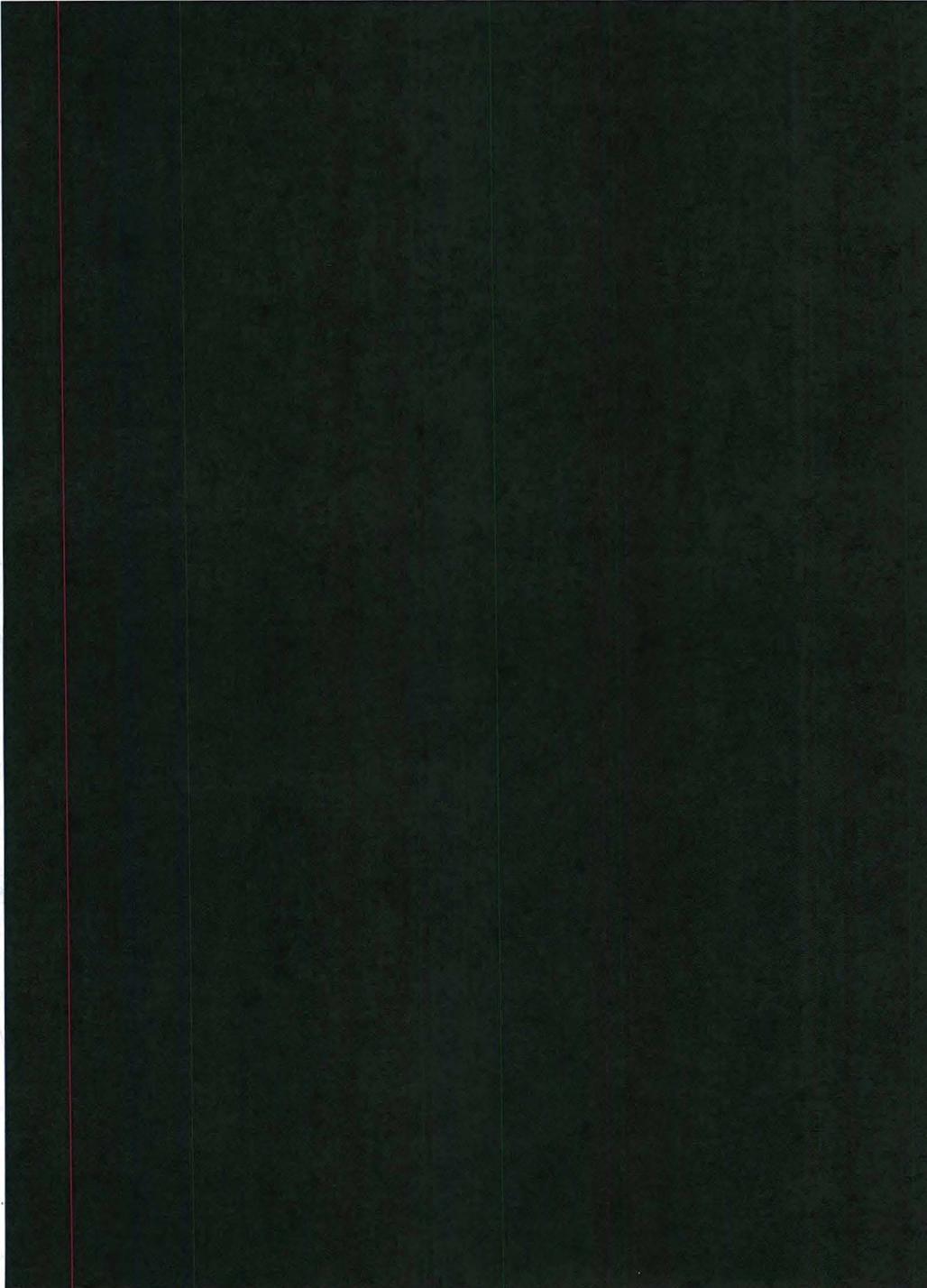
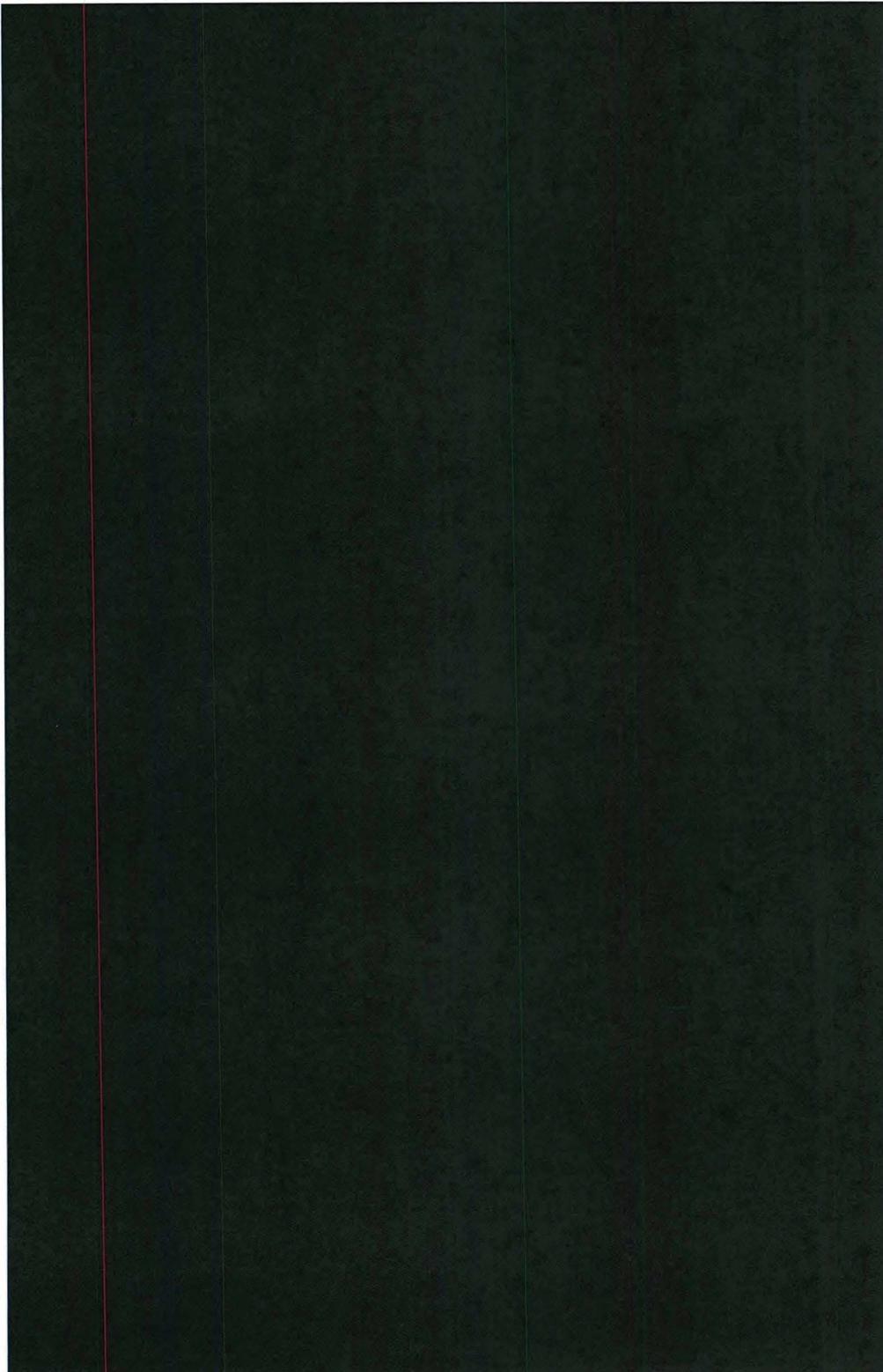


Figure 4 McIntosh 115kV



I. Cross References

Tables

Table 1 McIntosh 230/115kV Largest Constraints 3

Table 2 Preferred Plan Costs: McIntosh 400MVA..... 5

Table 3 Alternative 1 Costs: McIntosh 2nd 400 MVAW 5

Figures

Figure 1 Proposed McIntosh 400 MVA 2

Figure 2 Category P6 N-2 McIntosh 230/115kV Constraints 3

Figure 3 McIntosh Arial 6

Figure 4 McIntosh 115kV 7

Project Item: 1166202
 Job Name: MCINTOSH
 Job Desc: Replace McIntosh Bank ATX to a 400 MVA 230/115kV transformer (currently 280 MVA)
 Job Type: MODIFICATION
 Area: SOUTHERN-SAVANNAH
 In Service Date: 4/9/2019 (Scheduled) Facility Required Date: 6/1/2019
 Project Manager: [REDACTED]

Job ID: 1166202
 Job Status: WORKING
 Region: COASTAL
 Owner: GPCO

Activity Id	Activity Description	Activity Start	S/A	Activity Finish	S/A	Supv	Eng /For	Org Dur	Rem Dur	Float Total	Predecessor Activity	Pred Type	Lag Days
DESC	MCINTOSH		S		S		UNAS				HPB01	PR_SS	0
HPB01	BUDGET APPROVAL		S		S	KEIT	ANAL			0			0
PEGWO	CREATE WORK ORDER		S		S	UNAS	UNAS				HPB01	PR_FS	20
REPE2	SET UP PRE-ENGINEERING CONFERENCE		S		S	KEIT	ANAL				PEGWO	PR_FS	20
BAS01	SEND & ASSIGN COMMITTED BASELINE		S		S	KEIT	ANAL				REPE2	PR_FS	10
EECSK	PROTECTION & CONTROL PACKAGE		S		S	UNAS	UNAS				REPE2	PR_FS	10
DED01	PHYSICAL ENGINEERING		S		S	UNAS	UNAS				REPE2	PR_FS	15
ENVR01S	SUBSTATION SAMPLING		S		S	TOLC	UNAS				DED01	PR_SS	5
EECSKQC	P&C QUALITY CONTROL		S		S	UNAS	UNAS				EECSK	PR_FS	10
DEDRQN	ORDER PHYSICAL NON-STOCK MATERIAL		S		S	UNAS	UNAS				DED01	PR_SS	10
											REPE2	PR_FS	10
SHIPPING	MATERIAL LONGEST LEAD ITEM (Switch)		S		S	KEIT	ANAL				DEDRQN	PR_FS	0
DEDQA	PHYSICAL ENGINEERING QA		S		S	UNAS	UNAS				DED01	PR_FS	0
EEC01	CONTROL ENGINEERING		S		S	UNAS	UNAS				EECSK	PR_SS	5
											EECSKQC	PR_FS	5
DEDSF	SEND DRAWINGS TO SHOP FAB		S		S	UNAS	UNAS				DEDQA	PR_FF	0
DED02	TRANSMIT PHYSICAL ENGINEERING		S		S	UNAS	UNAS				DEDQA	PR_FS	0
EECRQN	ORDER CONTROL NON-STOCK MATERIAL		S		S	UNAS	UNAS				EEC01	PR_SS	15
EECQA	CONTROL ENGINEERING QA		S		S	UNAS	UNAS				EEC01	PR_FS	0
EEC02	TRANSMIT CONTROL ENGINEERING		S		S	UNAS	UNAS				EECQA	PR_FS	0
GCWPQA	PQA REVIEW		S		S	DCDA	UNAS				EEC02	PR_FS	0
EEGREV	BCA-E REVIEW		S		S	KEIT	ANAL				BAS01	PR_FS	0
											DED02	PR_FS	10
											EEC02	PR_FS	10
GTSREV	TEST REVIEW		S		S	UNAS	UNAS				EEC02	PR_FS	10
EECRLO1	DESIGN RELAY SETTINGS		S		S	UNAS	UNAS				EEC02	PR_FS	15
											EECSKQC	PR_FS	0
GEN01	GENERATION REVIEW		S		S	UNAS	UNAS				EECRLO1	PR_FS	0

Project Item: 1166202
 Job Name: MCINTOSH
 Job Desc: Replace McIntosh Bank ATX to a 400 MVA 230/115kV transformer (currently 280 MVA)
 Job Type: MODIFICATION
 Area: SOUTHERN-SAVANNAH
 In Service Date: 4/9/2019 (Scheduled) Facility Required Date: 6/1/2019
 Project Manager: ██████████
 EECM GATHER CONTROL MATERIAL

Job ID: 1166202
 Job Status: WORKING
 Region: COASTAL
 Owner: GPCO

EECRLQC	DESIGN RELAY SETTINGS QC	S		S	DRMO	UNAS		EEC02	PR_FS	20
								EECRQN	PR_FS	60
EECRL02	TRANSMIT RELAY SETTINGS	S		S	UNAS	UNAS		EECRL01	PR_FS	0
MCS01	RECEIVE MATERIAL	S		S	KEIT	ANAL		GEN01	PR_SS	10
GCW02	SHOP WIRING (2 panels)	S		S	DRMO	UNAS		EECRLQC	PR_FS	0
MAJ_EQPT	RECEIVE MAJOR EQUIPMENT (switch)	S		S	KEIT	ANAL		SHIPPING	PR_FS	45
GTSPQA	PANEL QUALITY ASSURANCE (2 panels)	S		S	MDCO	UNAS		EECCM	PR_FS	16
REPE3	SET UP PRE-CONSTRUCTION CONFERENCE	S		S	KEIT	ANAL		GCWPQA	PR_FS	0
GTS01	TEST & CUT-IN	S		S	UNAS	UNAS		MCS01	PR_SS	10
								SHIPPING	PR_FF	0
GCS01	SUBSTATION CONSTRUCTION	S		S	UNAS	UNAS		GCW02	PR_FS	10
								GCS01	PR_SS	-10
GCSEI01	REMOVE EQUIPMENT	S		S	JEWD	UNAS		EECRL02	PR_FS	0
GCW01	FIELD WIRING	S		S	DRMO	UNAS		GCS01	PR_SS	-5
								GTSREV	PR_FS	10
OUTAGE	SUB OUTAGE - CAPITAL	S		S	KEIT	ANAL		DEDSF	PR_FS	38.4
GCSEI02	INSTALL EQUIPMENT *	S		S	JEWD	UNAS		ENVR01S	PR_FS	12.8
GTS04	SIA TEST & CUT-IN	S		S	SCGO	UNAS		MAJ_EQPT	PR_FS	16
DED03	FINAL SUBSTATION INSPECTION	S		S	UNAS	UNAS		MCS01	PR_FS	24
HPB02	REQUIRED FINISH / IN-SERVICE DATE	S		S	KEIT	ANAL		GCS01	PR_SS	0
								GCS01	PR_SS	0
								GCW02	PR_FF	0
								GTSPQA	PR_FS	-24
								GCS01	PR_SS	0
								GCSEI01	PR_FS	0
								GTS01	PR_FF	-2
								GCS01	PR_FF	0
								DED03	PR_FS	0
								DESC	PR_FF	0
								GCSEI01	PR_FS	0
								GCSEI02	PR_FS	0

GEORGIA POWER COMPANY
Job Network Report

PUBLIC DISCLOSURE

Date:08/07/2017
Time:11:17:44 AM

Project Item: 1166202
Job Name: MCINTOSH
Job Desc: Replace McIntosh Bank ATX to a 400 MVA 230/115kV transformer (currently 280 MVA)
Job Type: MODIFICATION
Area: SOUTHERN-SAVANNAH
In Service Date: 4/9/2019 (Scheduled)
Project Manager: ██████████

Facility Required Date: 6/1/2019

Job ID: 1166202
Job Status: WORKING
Region: COASTAL
Owner: GPCO

GCW01	PR_FS	0
GTS01	PR_FS	0
GTS04	PR_FS	0
OUTAGE	PR_FS	0
REPE3	PR_FS	0

*** End of Report ***

PUBLIC DISCLOSURE

TMCRET40

GEORGIA POWER COMPANY

Date: 08/17/2017

Page 1 OF 3

ESTIMATED COST BY RETIREMENT UNITS

Time: 12:03:46PM

Project Item: 1166202

PE: 6499 PE Item:

Version: Budget Saved

Type Work: MODIFICATION

Work Order:

Facility Name: MCINTOSH

Facility Required Date: 6/1/2019

Nearest Town:

Originator: [REDACTED]

Description:

Replace McIntosh Bank ATX to a 400 MVA 230/115kV transformer (currently 280 MVA).

Per communication with [REDACTED] install the spare 400MVA, 230/115kV bank, company number [REDACTED] that is currently stored in the 230kV yard at Kraft Substation. Test reports and drawings are located on the S: drive in the major equipment files. [REDACTED] will replace this bank with a new purchase spare. Include transportation cost to move the bank from Kraft to McIntosh in the estimate. [REDACTED] 5/29/2017

Scope update: Retire the 25kV Reserve Station Service circuit currently fed from the tertiary of the existing bank. Resource Planning has agreed that [REDACTED] [REDACTED] 6/13/2017

Notes:

- (1) [REDACTED] has confirmed there are no overstressed 115kV breakers with the new 400 MVA bank (breakers 946, 952, 962, 982 and 992). (Updated [REDACTED] 4/28/2016).
- (2) [REDACTED] bonus rating is based on 1600 amp low-side switches.
- (3) May need to relocate Steam Plant Service. (Will retire station service to plant from the tertiary. [REDACTED] 5/12/17)
- (4) Per [REDACTED] (10/21/15), the following relays need to be replaced: HCB (pilot wire / 25kV RSS circuit), HU-4, BDD, IAC, KC-4, TD-5 and (Will replace relays on separate projects. [REDACTED] 5/12/17)
- (4b) at the McIntosh Steam Plant: HCB (pilot wire / 25kV RSS circuit) (Will replace on separate projects. [REDACTED] 5/12/17)

=====
P&C APPS
Add (1) SEL-387/GE-T60 - Autobank ATX
[REDACTED] 6/30/2017
=====

Control estimate by [REDACTED] 11/23/2015

- ESTIMATE INCLUDES:
- 1 BANK PANEL
 - 1 DCUB TREUTLEN LINE PANEL (SOCO STD)
 - 1 TRANSFER TRIP PANEL
 - 2 BREAKER CONTROL PANELS
 - 4 BUS DIFF PANEL (SOCO STD)
 - 1 BANK ALARM ANNUNCIATOR
 - CABLES
 - REMOVALS
 - CTRL DESIGN 700HRS
 - TEST 3120 HRS (3 PEOPLE)
 - APPS 224HRS

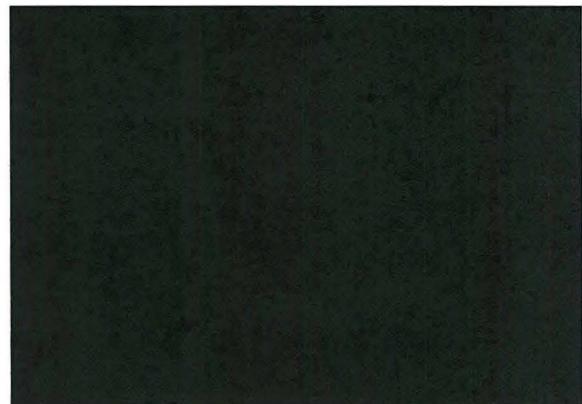
=====
Control estimate has been re-estimated per change of scope.
See estimate notes for more details.
[REDACTED] on 7/11/2017
=====

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
----------------------------	----	----------	----------	-------	-----------	-------

PLANT ADDITIONS

CONSTRUCTION(Estimator: [REDACTED])

AC DISTRIBUTION EQUIPMENT ACC	LT	1				
BUSWORK, ACCESSORIES	LT	1				
BUSWORK-CABLE, ALUMINUM	FT	800				
BUSWORK-TUBE, ALUMINUM	FT	800				
CONTROL CABLE	FT	9,050				
FIBER OPTIC CABLE, CONT. RUN	EA	100				
FOUNDATION - HIGH VOLTAGE	EA	11				
INSTRUMENT, CONTROLLING	EA	11				
INSTRUMENT, INDICATING	EA	1				
INSULATOR-POST 230 KV	EA	16				
INSULATOR-POST 69,115KV&161KV	EA	24				
LA-200.1 KV, 396KV, STA CLASS	EA	3				



PUBLIC DISCLOSURE

TMCRET40

GEORGIA POWER COMPANY

Date: 08/17/2017

Page 2 OF 3

ESTIMATED COST BY RETIREMENT UNITS

Time: 12:03:46PM

Project Item: 1166202

PE: 6499 PE Item:

Version: Budget Saved

Type Work: MODIFICATION

Work Order:

Facility Name: MCINTOSH

Facility Required Date: 6/1/2019

Nearest Town:

Originator: [REDACTED]

Discipline/Retirement Unit	UM	Quantity	Material	Labor	Equipment	Total
LA-21.1 KV, 48KV, STAT CLASS	EA	3				
MOVE ON/OFF JOB	LT	1				
PANEL / CABINET	EA	2				
POWER TRANSFORMER, ACC.	LT	1				
PROTECTIVE RELAYING TRANSCIEV	EA	1				
STR-STEEL, HV, SECT,BAY,SUPP	EA	11				
STR-STEEL, LV, SECT,BAY,SUPP	EA	2				
SWITCH-GO, AB, 3PH 230KV	EA	1				
TRANS, MEALS, ETC.	LT	1				
Discipline Total						
ENGINEERING (Estimator: [REDACTED])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
PLAN & PROJ (Estimator: [REDACTED])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
TEST (Estimator: [REDACTED])						
DIRECT ENGINEERING	LT	1				
Discipline Total						
Sub-Total PLANT ADDITIONS						
PLANT TRANSFER ADDITIONS						
CONSTRUCTION (Estimator: [REDACTED])						
POWER TRANSFORMER, 3P, 230 KV	EA	1				
Discipline Total						
Sub-Total PLANT TRANSFER ADDITIONS						
TOTAL PLANT ADDITIONS WITHOUT OVERHEADS						
PLANT REMOVALS						
CONSTRUCTION (Estimator: [REDACTED])						
INSTRUMENT, CONTROLLING	EA	7				
PANEL / CABINET	EA	2				
Discipline Total						
Sub-Total PLANT REMOVALS						
PLANT TRANSFER REMOVALS						
CONSTRUCTION (Estimator: [REDACTED])						
COOLING EQPT. (X INST.W/TFM)	EA	1				
LA-200.1 KV, 396KV, STA CLASS	EA	3				
LA-21.1 KV, 48KV, STAT CLASS	EA	3				
TRANSFORMER, CURRENT 115 KV	EA	1				
Discipline Total						
Sub-Total PLANT TRANSFER REMOVALS						
TOTAL PLANT REMOVALS WITHOUT OVERHEADS						
MAINTENANCE						
Sub-Total MAINTENANCE						
TOTAL MAINTENANCE						

PUBLIC DISCLOSURE

TMCRET40

GEORGIA POWER COMPANY

Date: 08/17/2017

Page 3 OF 3

ESTIMATED COST BY RETIREMENT UNITS

Time: 12:03:46PM

Project Item: 1166202

PE: 6499 PE Item:

Version: Budget Saved

Type Work: MODIFICATION

Work Order:

Facility Name: MCINTOSH

Facility Required Date: 6/1/2019

Nearest Town:

Originator: 

ESTIMATE SUMMARY TOTALS

Plant Additions (Labor, Matl, Eqp)

Overheads

Total Plant Additions

Plant Removals (Labor, Matl, Eqp)

Overheads

Total Plant Removals

Plant Transfer Additions (Material Only)

Plant Salvage

Total PI CIAC

Total Cash Required

Total Maintenance Cost

Original Cost Retired

Plant Transfer Removal (Material Only)

*** End of Report ***



[H]

APPENDIX

[H1]

IDENTIFIED PROBLEMS

&

SOLUTIONS

THERMAL AND VOLTAGE PROBLEM REPORTS

Sections H1a and H1b show the Thermal Problem Reports and Voltage Problem Reports, respectively, that were generated during the statewide screening process for each major version of the 2018-series base cases. In the Thermal Reports, for each transformer or breaker-to-breaker line for which a problem was identified, the bottom part of the entry, organized by year, shows what section or sections are overloaded, pre- and post-contingency loading, and the facility rating. In the Voltage Reports, for each bus with voltage problems, the pre and post-contingency voltages are shown along with the calculated deviation. For both reports, the number of contingencies that cause a problem, and the worst contingency, case type and unit off are shown.

For both reports, the top section shows a TEAMS project number, if any, along with the Need Date and Project Name. Underneath the Project Name is a Comment by the planner indicating how the issue was expected to be addressed at the time, whether with an operating guide, a project, or an explanation as to why the apparent problem is actually not a violation of the planning guidelines.

These reports were printed from a live database. As a result, the TEAMS Need Date is the date that the project is timed for AT THE TIME OF PRINTING, as shown at the bottom left of the page. It should match the ultimate timing of the project in the Ten Year Plan. The date in the Comment field shows when a project was timed AT THE TIME OF THE ANALYSIS. These two need dates will usually match, but in some cases projects have been retimed later in the process, so there may be a mismatch. These differences can arise because of updated generation dispatch patterns between case versions, because of interactions between projects, or because of a need identified through other studies such as interface analysis, N-2 screens, etc.

Because these reports contain Critical Energy Infrastructure Information, their distribution is subject to regulation by FERC under the Code of Federal Regulations, Section 388.113. Therefore, these reports are redacted in their entirety in the Public Disclosure version of the IRP filing.

[H1a]

THERMAL PROBLEMS

&

SOLUTIONS

2019-2028 TP-East Thermal Problems STRE- v1A (SHOTD)_Rev
Pages 1-27 are redacted in their entirety.

[H1b]

VOLTAGE PROBLEMS

&

SOLUTIONS

2019-2028 TP-East Voltage Problems - v1A (SHOTD)

Pages 1-15 are redacted in their entirety.

[H2]

LOAD FLOW DATA FILES

LOAD FLOW CD REDACTED

Load Flow Data CD – File Structure and Instructions

Summer Peak Cases

All 2018 series Summer Peak Cases are located under the file folder titled Base Summer Peak Cases. This folder contains the v1A Base Summer Peak Cases for 2019-2028.

To select a 2019 Base Summer case, double click the “Base Summer Peak Cases” folder. You should see 10 files with a naming structure of SXXv1As18 - CEll.sav. The XX designates the year of the case. For example, the 2019 case is named S19v1As18 - CEll.sav.

IDEV Files

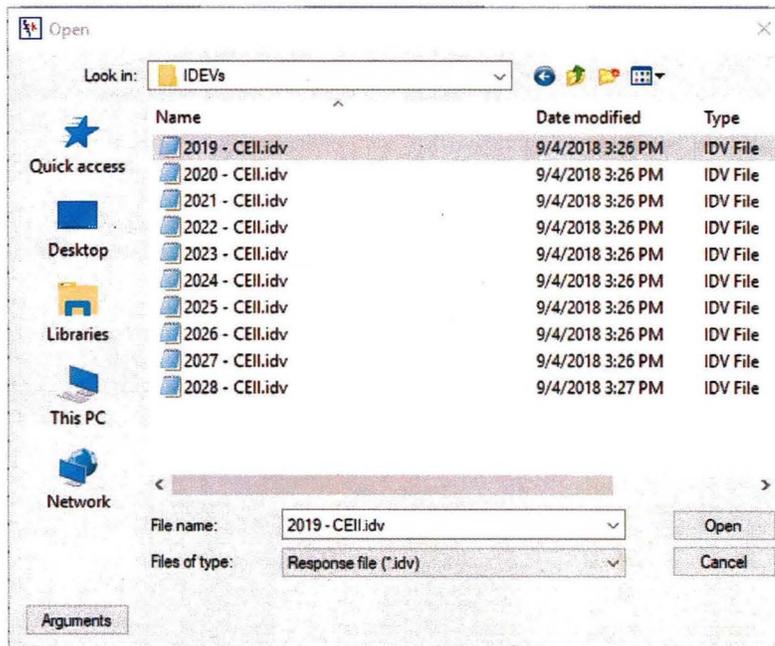
All 2018 series Summer Peak Cases IDEV files are located under the file folder titled IDEVs. This folder contains the IDEV files for the corresponding v1A cases.

To select the 2019 IDEV file for the 2019 Summer Peak Case from the v1A cases, double click the “IDEVs” folder. You should see 10 files with a naming structure of XXXX - CEll.idv. The XXXX designates the year of the IDEV file. The 2019 IDEV is under the filename of 2019 - CEll.idv. To view the information contained in the IDEV, open the IDEV file in a text editor. The text or comment areas indicate the projects that will be removed from the cases.

Applying IDEV File

To apply an IDEV please follow the steps outlined below:

1. Open a case in PSS/E (e.g. 2019 v1A Summer Case – S19v1As18 - CEll.sav)
2. Click on “I/O Control” and select “Run Program Automation File”
3. The following screen will open

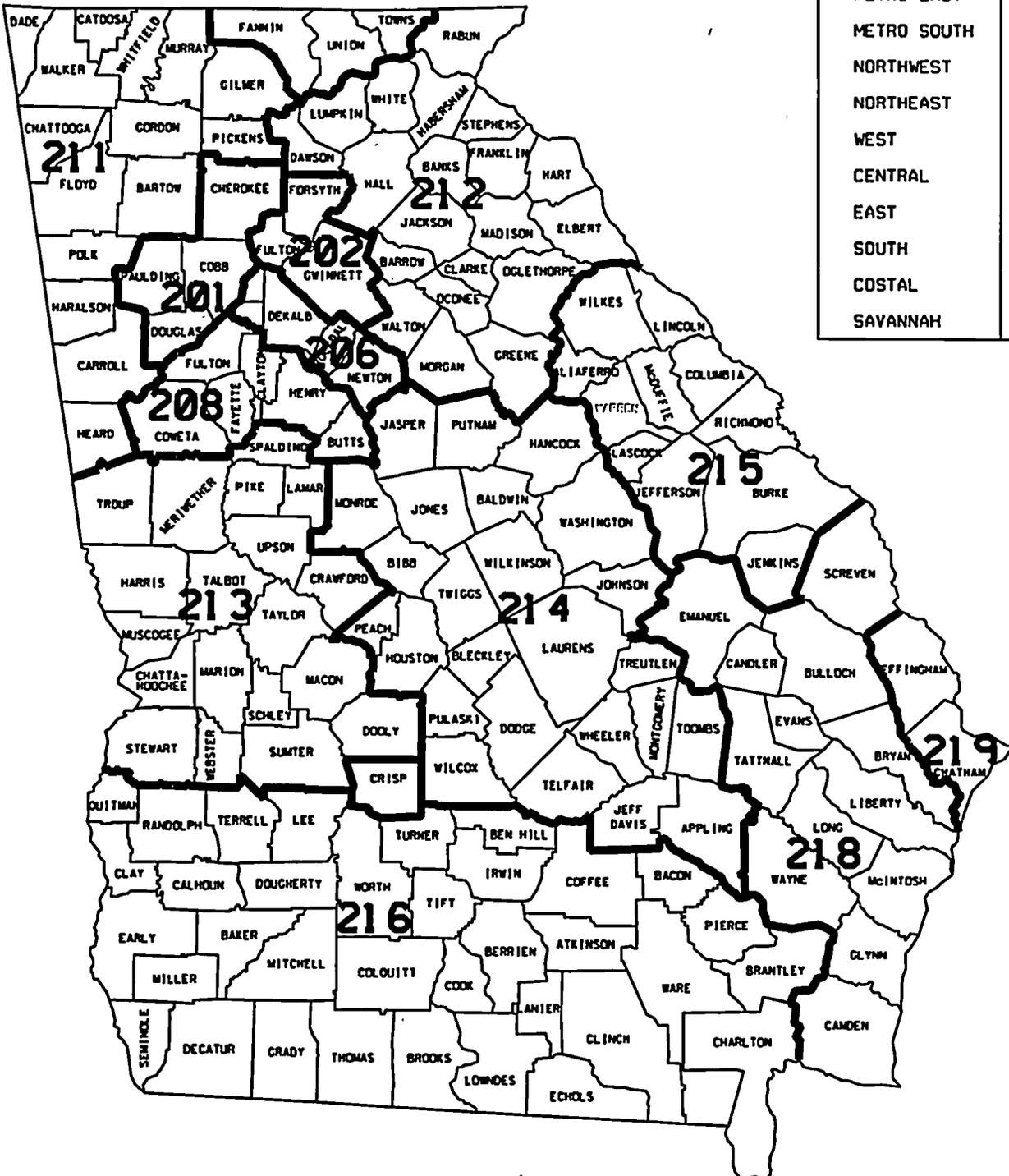


Select the corresponding IDEV file for the case and click open. This will run the IDEV file and remove the projects from the case. This will create the Base Stripped Case used in the screening process.

[H3]

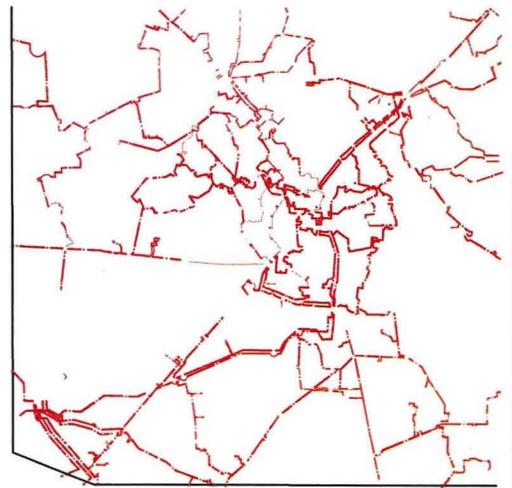
ITS MAPS

GEORGIA POWER REGION BOUNDARIES

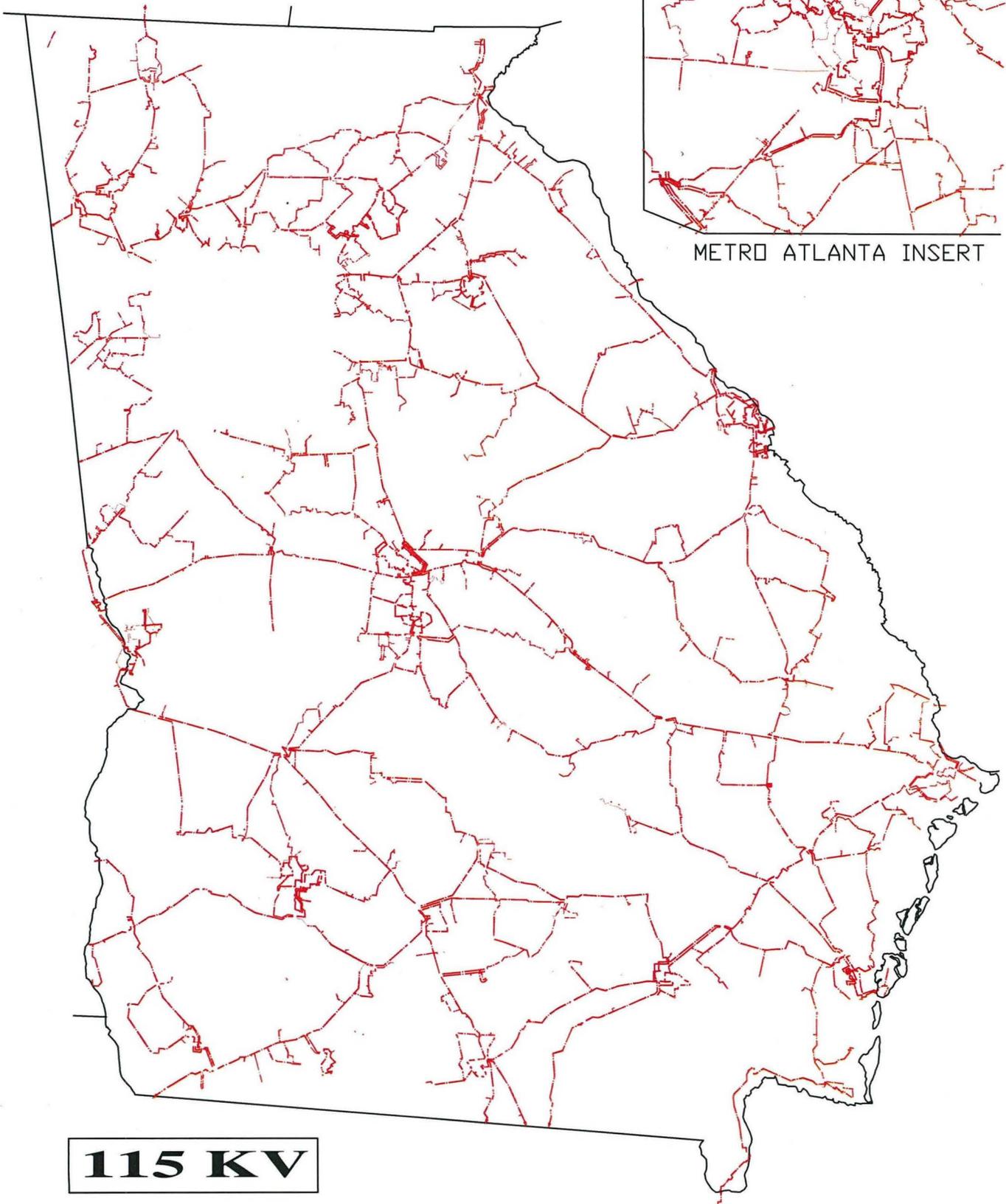


REGION	ZONE *
METRO WEST	201
METRO NORTH	202
METRO EAST	206
METRO SOUTH	208
NORTHWEST	211
NORTHEAST	212
WEST	213
CENTRAL	214
EAST	215
SOUTH	216
COSTAL	218
SAVANNAH	219

GEORGIA INTEGRATED TRANSMISSION SYSTEM
115KV LINES

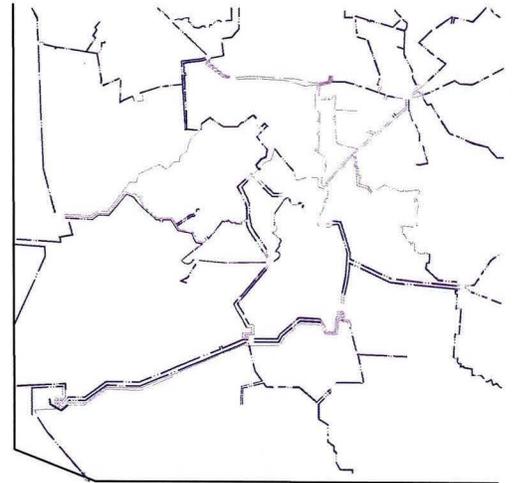


METRO ATLANTA INSERT



115 KV

GEORGIA INTEGRATED TRANSMISSION SYSTEM
230KV LINES

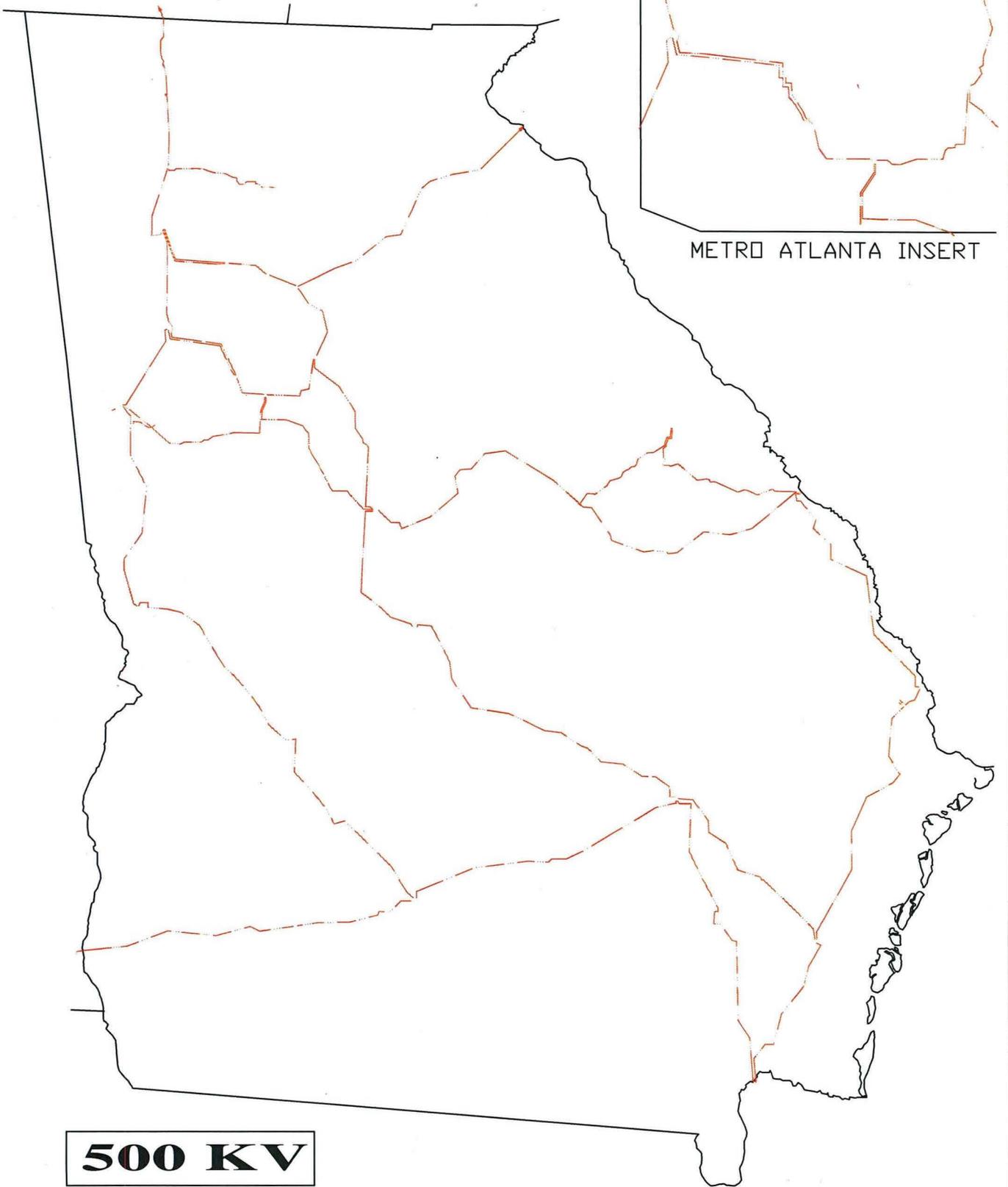


METRO ATLANTA INSERT



230 KV

GEORGIA INTEGRATED TRANSMISSION SYSTEM
500KV LINES



METRO ATLANTA INSERT

500 KV

[H4]

**ACRONYMS &
TECHNICAL DEFINITIONS**

Acronyms:

BCA – Budget Change Authorization, documentation that provides information about the scope, budget, and schedule for capital projects at Georgia Power

CAP – Corrective Action Plan, filed annually with NERC

CEII – Critical Energy/Electric Infrastructure Information, defined by FERC as “specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual)” that meets conditions that can be found on FERC’s website: <https://www.ferc.gov>

Cooperative Energy – A Mississippi electric cooperative, formerly called SMEPA (South Mississippi Electric Power Association)

Dalton – City of Dalton, Georgia ITS Participant

FCITC – First Contingency Incremental Transfer Capability

FERC – Federal Energy Regulatory Commission

FRCC – Florida Reliability Coordination Council

GPC – Georgia Power Company, Georgia ITS Participant

GTC – Georgia Transmission Corporation, Georgia ITS Participant

ITS – Integrated Transmission System

IWG – Interface Working Group, a working group that is part of TPWG

JETS – Job Estimating and Tracking System

Joint Committee – Joint Committee for Planning and Operations

JSOp – Joint Sub-Committee for Operations

JSTP – Joint Sub-Committee for Transmission Planning

LTSG – SERC Long – Term Study Group

MEAG – Municipal Electric Authority of Georgia, Georgia ITS Participant

MISO – Midcontinent Independent System Operator. When discussed in terms of the SBA interface, MISO refers to the interconnections with Entergy and Cooperative Energy.

MMWG – Multi-regional Modeling Working Group (NERC Group)

MVA – Megavolt Amperes, unit to measure apparent power

NERC – North American Electric Reliability Council

OPC – Oglethorpe Power Corporation

PE – Plant Expenditure

PowerSouth – PowerSouth Energy Cooperative

SAV – Savannah area transmission network

SBA – Southern Balancing Authority includes Southern Companies, GTC, MEAG, and Dalton as primary transmission providers.

SCE&G – South Carolina Electric & Gas

SCPSA – South Carolina Public Service Authority

SCS – Southern Company Services

SERC – SERC Reliability Corporation

STWG – Sub-Transmission Working Group

TEAMS – Transmission Evaluation and Management System

TIN – Transmission Improvement Notification

TPRT – Transmission Project Review Team

TPWG – Transmission Planning Working Group, comprised of Transmission Planning representatives from each ITS Participant, meets monthly

TSR – Transmission Service Request

TVA – Tennessee Valley Authority

VACAR – Subregion of SERC, Virginia and Carolina Companies. When discussed in terms of the SBA interface, VACAR refers to the interconnections with Duke, SCE&G and SCPSA.

Technical Definitions:

Base Transfers – transfers between balancing authorities that are modeled in the base cases utilized during interface evaluations. Base transfers in power flows used for interface import or export evaluations may not include all firm transactions in the opposite direction of the study transfers.

TRM (Transmission Reliability Margin) – amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure under a reasonable range of uncertainties in system conditions.

CBM (Capacity Benefit Margin) – amount of transmission transfer capability reserved by load serving entities or Resource Planners to ensure access to generation from interconnected systems to meet generation reliability requirements. Reservation of CBM provides for the reduction of installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements.

ITC (Incremental Transfer Capability) – amount of transfer capability that can be accommodated in addition to the modeled base transfers.

TTC (Total Transfer Capability) – base transfers plus incremental transfer capability

ATC (Available Transfer Capability) – a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the Transmission Reliability Margin (TRM), less the sum of existing transmission commitments (which includes retail customer interface reservations for future load growth and the Capacity Benefit Margin).

Loop Flows – the difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path. Synonyms: Parallel Path Flows, Unscheduled Power Flows, and Circulating Power Flows

Generation Loop Flows – loop flows occurring from the configuration of the network and location of generating units

Transaction Loop Flows – loop flows resulting from electric power transactions and the configuration of the network.

NLR (Native Load Reservations) – interface and internal transmission reservations that the Federal Energy Regulatory Commission allows native load customers to reserve for future load growth.

TSA (Transmission Service Agreements) – power transactions that have been granted firm status. Normally these transactions are point–to–point service from a generation plant or control area to another control area or native load.

Operating Reserves – additional generation available in generating units already on line or that can be made available within 15 minutes in case of generation emergencies.